Staff Exhibit No. 202
Date 6-15-15 Reporter AT
File No. ER-2014-0370

MISSOURI PUBLIC SERVICE COMMISSION

STAFF'S

RATE DESIGN

AND

CLASS COST-OF-SERVICE

REPORT

KANSAS CITY POWER & LIGHT COMPANY

CASE NO. ER-2014-0370

Jefferson City, Missouri
April 16, 2015

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-2014-0370

AFFIDAVIT OF MICHAEL S. SCHEPERLE

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

Michael S. Scheperle, of lawful age, on his oath states: that he has participated in the preparation of the foregoing Staff Report in pages 1-6, 29-34 + 36; that he has knowledge of the matters set forth in such Report; and that such matters are true to the best of his knowledge and belief.

Michael Scheperle
Michael S. Scheperle

Subscribed and sworn to before me this 16th day of April, 2015

SUSAN L. SUNDERMEYER
Notary Public - Notary Seal
State of Missouri
Commissioned for Callaway County
My Commission Expires: October 28, 2018
Commission Number: 14942086

Susan L Sundermeyer
Notary Public

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-2014-0370

AFFIDAVIT OF ROBIN KLIETHERMES

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

Robin Kliethermes, of lawful age, on her oath states: that she has participated in the preparation of the foregoing Staff Report in pages 6 - 36; that she has knowledge of the matters set forth in such Report; and that such matters are true to the best of her knowledge and belief.

Robin Kliethermes

Subscribed and sworn to before me this 16th day of April, 2015.

SUSAN L. SUNDERMEYER
Notary Public - Notary Seal
State of Missouri
Commissioned for Callaway County
My Commission Expires: October 28, 2018
Commission Number: 14942086

Notary Public

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-2014-0370

AFFIDAVIT OF SARAH L. KLIETHERMES

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

Sarah L. Kliethermes, of lawful age, on her oath states: that she has participated in the preparation of the foregoing Staff Report in pages 6 – 29; that she has knowledge of the matters set forth in such Report; and that such matters are true to the best of her knowledge and belief.

Sarah L. Kliethermes

Sarah L. Kliethermes

Subscribed and sworn to before me this 16th day of April, 2015.

SUSAN L. SUNDERMEYER
Notary Public - Notary Seal
State of Missouri
Commissioned for Callaway County
My Commission Expires: October 28, 2018
Commission Number: 14942086

Susan L. Sundermeyer

Notary Public

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-2014-0370

AFFIDAVIT OF DANA E. EAVES

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

Dana E. Eaves, of lawful age, on his oath states: that he has participated in the preparation of the foregoing Staff Report in pages 36-43; that he has knowledge of the matters set forth in such Report; and that such matters are true to the best of his knowledge and belief.

Dana E. Eaves

Dana E. Eaves

Subscribed and sworn to before me this 16th day of April, 2015

SUSAN L. SUNDERMEYER
Notary Public - Notary Seal
State of Missouri
Commissioned for Callaway County
My Commission Expires: October 28, 2018
Commission Number: 14942086

Susan L. Sundermeyer

Notary Public

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STAFF'S

RATE DESIGN

AND

CLASS COST-OF-SERVICE

REPORT

I. Executive Summary

Staff's recommended increase in revenue requirement for KCPL is based upon an adjusted test year for the twelve months ending March 31, 2014, and updated through December 31, 2014. Additionally, Staff calculated an estimated allowance of $65 million for known and measureable changes through the true-up period of May 31, 2015. Because of changes expected for the true-up items through May 31, 2015, that are not known and measurable at this time, Staff's revenue requirement for KCPL will change when the true-up process is completed in this case. Staff's recommended revenue requirement increase for KCPL is $82,383,073 to $91,283,864 based on a return on equity ("ROE") range of 9.00% to 9.50%. Staff's final recommendation will be based on its true-up audit.

KCPL has six (6) service classifications:

1. Residential ("Res")
2. Small General Service ("SGS")
3. Medium General Service ("MGS")
4. Large General Service ("LGS")
5. Large Power Service ("LPS")
6. Total Lighting ("Lighting")

Each service classification has several rate schedules and tariff rate riders. KCPL has approximately sixty-eight (68) rate schedules in its tariff to meet the specific needs of its customers.

KCPL's residential rate schedules consist of the following:

- Residential General Use Rate Schedule;
- Separate All Electric Rate schedules (one or two meters);
- Residential Time of Day rate schedule;
- Residential Other Use; and
- Residential Time of Use Smart Grid Demonstration

The commercial and industrial rate schedules consist of the following:

- SGS rate schedules include: secondary, primary, secondary all electric-frozen and primary all electric-frozen.
- MGS rate schedules include: secondary, primary, secondary all electric-frozen, and primary all electric-frozen.
- LGS rate schedules include: secondary, primary, secondary all electric-frozen, and primary all electric-frozen.
- LPS rate schedules include: secondary, primary, substation, and transmission.

The lighting class includes various lighting requirements and traffic signal descriptions:

- Missouri commercial area lights ("ALC");
- Missouri residential area lights ("ALR");
- Kansas City School District parking lot lights ("OLS");
- Missouri street lighting public & Kansas City street lights ("MLC, MLI, MLM, MLS");
- Missouri traffic signals ("TSL"); and
- Missouri street light – LED ("MLL")

Due to the unavailability of hourly load research data to develop demand allocators for each individual rate schedule to be used in Staff's class cost of service study ("CCOS" study), Staff combined the rate schedules described above into each of the six designated service classifications ("classes"): Res, SGS, MGS, LGS, LPS and Lighting.[1]

As explained later in this report, Staff recommends that the allocation of any rate increase for KCPL that is ordered be accomplished with a four-step process:

1. Based on CCOS results, Staff recommends an increase/decrease to the current base revenue on a revenue-neutral basis to various classes of customers. At this time, Staff is not recommending any revenue-neutral adjustments to any class as each class would be close to Staff's CCOS study results within a realm of reasonableness range. The revenue neutral shifts can be determined by subtracting the overall estimated 11.44% revenue increase from each class's calculated percentage change in revenues. On a revenue neutral basis, the following shifts are calculated: Res, 0.97%; general service class's combined (SGS, MGS, LGS), -3.36%; LPS, 4.94%; and lighting, -1.33%.

2. Staff determined the amount of revenue responsibility increase to award to each KCPL class based on Staff's estimated mid-point revenue requirement recommendation. Staff further recommends that an additional constraint (revenue requirement after true-

[1] Hourly load research data was only available for the rate class as a whole and not by each individual rate schedule within the class.

up) be placed to ensure no class receives an overall reduction in its rate revenue responsibility while another class receives an overall increase in its rate revenue responsibility.

3. Staff recommends the first energy block rate of the frozen winter All-Electric Service rate schedules for the SGS, MGS, and LGS rate classes be increased by an additional 5%[2]. This is further discussed in the rate design section of Staff's CCOS Report and in Schedules MSS-D6, MSS-D7, and MSS-D8.

4. Staff recommends that each rate component of each class be increased across-the-board for each class on an equal percentage basis after applying steps 1 through 3 above. Staff recommends that, based on its CCOS study results and policy considerations, the residential and all other customer charges increase by the average increase for each applicable class.

Rate Structure[3] changes:

5. The Res class has three main sub-class rate classifications; general use ("ResA"), one meter general use and space heat ("ResB") and two meter rate with general use on one meter and a separate meter for space heating ("ResC"). These Res class rate classifications are consistent with each other for the most part as each has a customer charge per month and energy charges per season (winter/summer). One of Staff's objectives is to get each residential rate classifications or rate schedule consistent with each other. To that end, Staff is recommending a rate structure change to ResB to make it consistent with ResA and ResC. Staff understands, that KCPL has also recommended this rate structure concept to make all three residential rate structures the same. This is further detailed in Staff's rate design section.

6. The general service group consists of a small, medium, and large rate class. These classes are SGS, MGS and LGS. Customers may switch (rate switchers) within the general service group with some rate schedules frozen to existing customers. For the most part, the general service classes have a consistent rate structure with Staff supporting the existing rate structure and continuity. In the past and in this case, Staff recommended rate component adjustments (i.e., winter only adjustment) while still maintaining the existing rate structure.

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[2] 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.

[3] Rate structure is the composition of the various charges for the utility's products. These include customer charges, energy (usage) charges, peak (demand) charges, facilities charges, etc. More elaborate variations include seasonal variations, time-of-day differentials, declining/inclining block rates, and hours-use rates. These variations are used to send price signals to the customer(s).

This report is organized into the following sections:

- Executive Summary
- Class Cost-of-Service and Rate Design Overview
- Staff Class Cost-of-Service Study
- Rate Design
- Fuel Adjustment Clause
- Residential Customer Charge
- Commercial and Industrial Customer Charges

Current Class Revenues and Cost to Serve

Table 1 below shows the rate revenue responsibility 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 Revenue Requirement Cost of Service Report ("COS Report"). This is based on Staff's estimated mid-point revenue requirement recommendation. For rate design purposes Staff combined the revenue contributions and cost of service results for the SGS, MGS and LGS general service classes, into a single general service rate group, due to rate switching that can occur between these rate classes. Table 2, below shows Staff's class cost of service study results with the general service class separated as well as combined.

Table 1

Class	CCOS Increase	Percent Increase	CCOS Increase	Percent Increase
Residential			$ 35,417,070	12.41%
General Service Rate Group			$ 28,402,890	8.08%
Small General Service	$ 920,261	1.87%		
Medium General Service	$ 8,597,631	8.32%		
Large General Service	$ 18,884,998	10.68%		
Large Power Service			$ 22,049,532	16.38%
Lighting			$ 981,699	10.11%

Staff developed its analysis of KCPL's cost of serving each class using inputs taken from Staff's COS Report, including the Staff Accounting Schedules, filed in this case on April 3, 2015. Staff's recommended revenue requirement for KCPL is $82,383,073 to $91,283,864 based on a return on equity (ROE) range of 9.00% to 9.50%. Staff will further update the case for KCPL to include actual results for the true-up period ending May 31, 2015.

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 responsibility 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 responsibilities 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.

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

A utility incurs expenses to provide service to its customers. The purpose of a CCOS study is to determine whether each class of customers is providing the utility with the level of revenue necessary to cover (1) the utility's ongoing expenses directly assigned or allocated to provide electric service to that class of customers and (2) a return on the utility's investments directly assigned or allocated to provide service to that class of customers. A CCOS study provides a basis for allocating and/or assigning the utility's total cost of providing electric service to all the customer classes in a manner reasonably reflecting cost causation. Staff's CCOS study is a continuation and refinement of Staff's cost-of-service revenue requirement study, resulting in a reasonable allocation of the costs incurred in providing electric service to each of KCPL's customer classes. Since those costs equate to KCPL's revenue requirement as determined by Staff in its Cost of Service Report filed April 3, 2015, the results of Staff's CCOS study are the initial basis for Staff's recommended class revenue requirements of each KCPL customer class which equitably shares KCPL's total annual cost of providing electric service among them. As discussed in the sections of this report concerning rate design, consideration of policy, subsidy, meeting of incremental costs, and promotional practices are also taken into account in Staff's ultimate recommendation of KCPL class revenue recovery through rate design.[4]

Staff Expert/Witness: Robin Kliethermes

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

Staff performed a Detailed Base, Intermediate, and Peak ("BIP") study that is the basis for Staff's recommended cost-causation results. The results of Staff's CCOS study appear in Table 1 above and are outlined in Table 2 below. Staff developed its class allocators using the six designated classes discussed in the Executive Summary. Staff separately analyzed each of the general service classes in developing its allocators and allocating costs to the

[4] Schedule CCOS-1 provides fundamental concepts, terminology, and definitions used in CCOS studies and rate design. It addresses functionalization, classification, and allocation as used in CCOS studies.

classes. Given the ability of customers to shift among the general service classes, and the importance of maintaining rate continuity among those classes, Staff consolidated the general service classes' results into a general service rate group for purposes of presenting its CCOS results. Staff's CCOS study provided the investment and costs associated for KCPL to provide service to these classes, as compared to the revenues currently provided by these classes. .

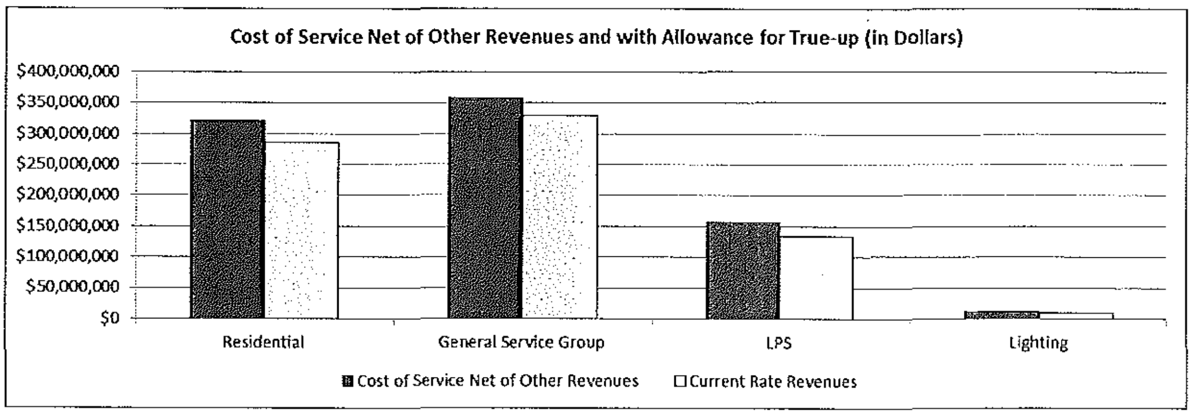
Table 2

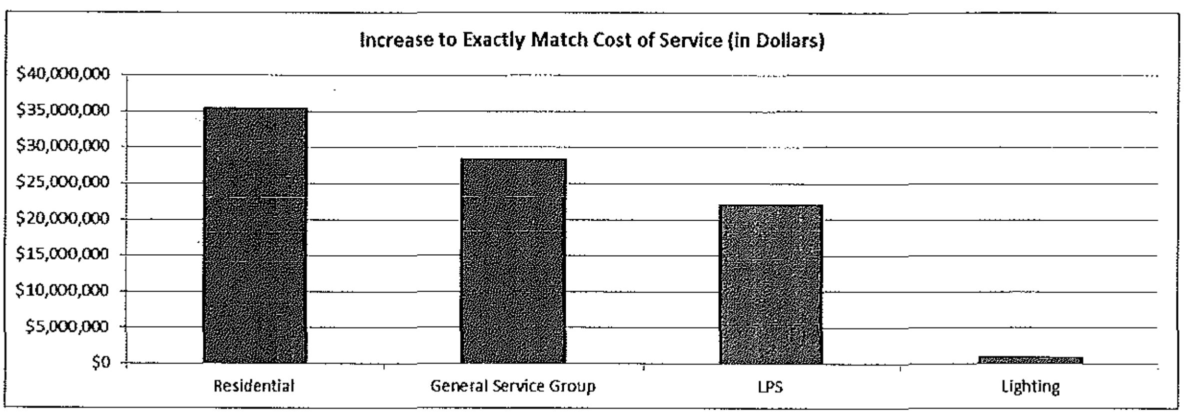
Summary of Staff's Class Cost of Service Results

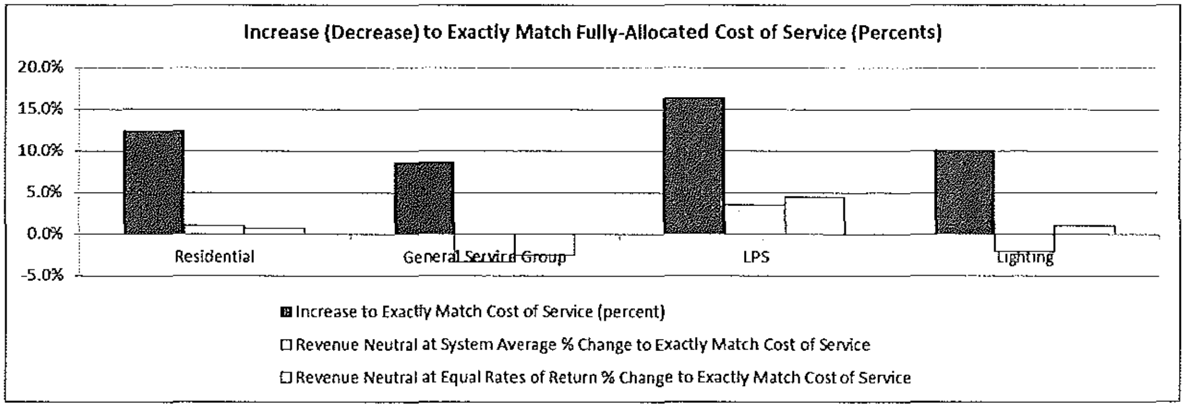
	Residential	General Service Group	LPS	Lighting
Class Cost of Service	$333,176,406	$379,815,071	$169,269,308	$11,547,333
Current Rate Revenue	$285,358,650	$329,518,638	$134,591,606	$9,713,513
Current Other Revenue (net of True-up Allowance)	$12,400,686	$21,893,543	$12,628,170	$852,121
Total Current Revenue (net of True-up Allowance)	$297,759,336	$351,412,181	$147,219,776	$10,565,634
Revenue Above (Below) Cost of Service	$35,417,070	$28,402,890	$22,049,532	$981,699
% Change to Exactly Match Cost of Service	12.41%	8.08%	14.98%	9.29%
Revenue Neutral at System Average % Change to Exactly Match Cost of Service	0.9713%	-3.3576%	3.5372%	-2.1487%
Revenue Neutral at Equal Rates of Return % Change to Exactly Match Cost of Service	0.7362%	-2.4719%	4.4147%	1.0573%
Contribution over Expense at Current Rates (net of True-up Allowance)	$26,635,715	$39,669,925	$7,951,786	$655,474

The changes shown in Table 2 are the changes to the current rate revenues of each customer class required to exactly match that customer class' 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 KCPL'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. Discussed below are two methods of calculating revenue neutral increases. The first method is to calculate the revenue neutral increase that would be necessary for each class to match its cost of service by subtracting the overall system average increase of 11.44% from each customer class' required percentage increase. This provides the revenue-neutral adjustment to rate revenue that would be necessary to match the revenues KCPL should receive from that class to KCPL's cost to serve that class shown in Table 2 if the increase is spread evenly among the classes at the rate of return currently provided by each class. A second method of finding revenue neutral increase is to examine the expense level of each class' cost of service independent of that class' contribution to return on ratebase. This second method finds the revenue neutral shifts to exactly match each class' revenue responsibility to its cost of service while providing an equalized return on ratebase among those classes. The required revenue increase to match cost of service is provided below expressed graphically in both dollars and percent, as well as on the revenue neutral bases.





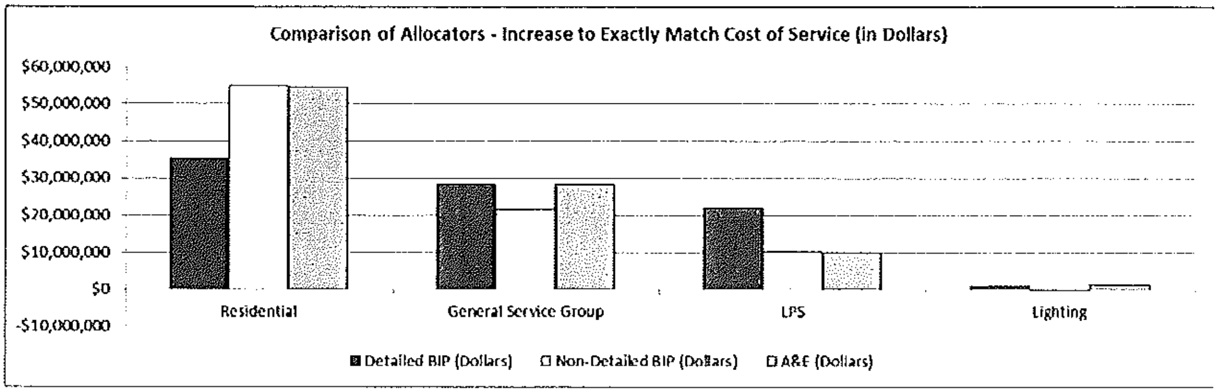


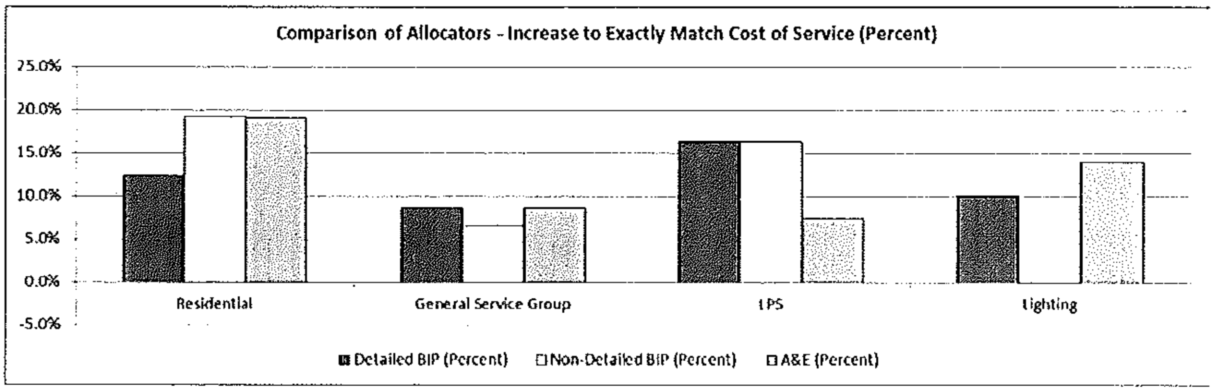
Staff also studied allocation of production and other related costs (capacity, energy, O&M, fuel in storage, and other revenues) using alternate production allocation methods of a non-detailed BIP study similar to that used by Staff in KCPL's last general rate case, and an Average and Excess 4 Non-Coincident Peak ("A&E 4 NCP") study to assess the reasonableness of the A&E 4 NCP study KCPL performed.[5] These results are presented in Table 3 and the associated graph below.

Table 3

Comparison of CCoS Results by Production-Related Allocator (Dollars and Percent)				
	Residential	**General Service Group**	**LPS**	**Lighting**
Detailed BIP (Dollars)	$35,417,070	$28,402,890	$22,049,532	$981,699
Detailed BIP (Percent)	12.4%	8.6%	16.4%	10.1%
Non-Detailed BIP (Dollars)	$54,951,179	$21,706,178	$10,205,133	-$11,283
Non-Detailed BIP (Percent)	19.3%	6.6%	16.4%	-0.1%
A&E (Dollars)	$54,562,826	$28,402,890	$10,074,946	$1,361,638
A&E (Percent)	19.1%	8.6%	7.5%	14.0%

[5] Non-coincident peak refers the load of each class, regardless of the time of the system peak.





Staff's detailed BIP method takes into consideration the differences in the capacity costs associated with units that run at a stable level much of the year, versus the capacity costs associated with units quickly dispatched only a few hours a year, as well as those units that have a cost and operation characteristic in between those extremes. Staff's detailed BIP method also considers the inverse relationship between the cost of capacity and the cost of energy produced by base, intermediate and peaking units. Other common CCOS methods tend to assume that energy costs the same amount regardless of the hour of consumption or the source of the energy. Other common CCOS methods do not give the level of consideration to the operating characteristics of plants, and assume that capacity costs are equal among types of plants.

Because the detailed BIP method most reasonably recognizes the relationship between the cost of the generating units required to serve various levels of demand and energy requirements relative to the cost producing energy at them, Staff recommends reliance on its detailed BIP study. However, Staff notes that its non-detailed BIP and A&E study results are generally consistent with the detailed BIP study results to a level of precision typically relied on for interclass allocation purposes.[6]

A CCOS study is not precise and is used only as a guide for designing rates. For example, other factors such as bill impacts, simplicity, rate stability, fairness among different consumers, customer understandability, meeting incremental costs, and public policy considerations are also considered. Staff's CCOS study used costs and revenues from Staff's accounting information and other sources as outlined below. Staff's allocation of costs and revenues to the customer classes is described in the sections that follow.

Staff Experts/Witnesses: Sarah Kliethermes and Robin Kliethermes

A. Data Sources

Staff's CCOS study utilized Staff's revenue requirement recommendations as filed on April 3, 2015, in Staff's COS Report. This data includes:

- Adjusted Missouri investment and expense data by FERC account;
- Normalized and annualized rate revenues;
- Net fuel and purchased power costs and revenues;
- Other operating and maintenance expenses;
- Depreciation and amortizations;
- Taxes; and
- For each class, Staff's determination of weather-adjusted, customer-coincidental peaks, customer-non-coincidental peaks, customer-maximum peaks, and annual energy.

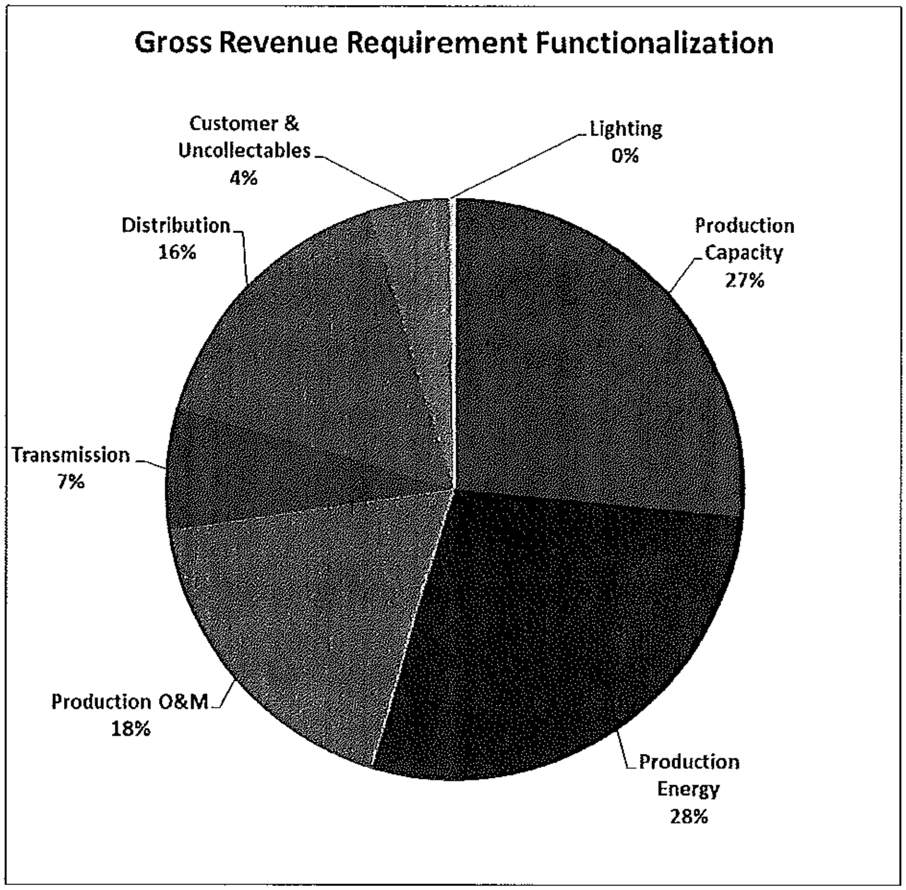
[6] In some winter months KCPL's system peak is driven by heating load, and the peak is set in a nighttime hour. Because these winter peaks cause KCPL's lighting load's peak to coincide with the KCPL system coincident peak, the A&E allocator shifts more capacity costs to lighting than the either the detailed BIP or the non-detailed BIP.

In addition, Staff obtained data from KCPL's workpapers from this case, which include allocation factors for specific customer costs allocations. These allocation factors relate to information on services, meters, meter reading, uncollectible accounts, customer service, and customer deposits.

Staff Experts/Witnesses: Sarah Kliethermes and Robin Kliethermes

B. 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 Capacity and Energy. "Production-Capacity" costs are those costs directly related to the capital cost of generation. "Production-Energy" costs are those costs related directly to the customer's consumption of electrical energy (i.e., kilowatt-hours) and consist primarily of fuel, fuel handling, and the energy portion of net interchange power costs. The pie chart below shows the approximate percentage of total costs associated with each major function.



Tables 4 and 5 and the accompanying charts provided below show the functionalization in dollars by class and by the percent of each function in that class' class cost of service.

Table 4

Functionalized Costs by Class (Dollars)				
	Residential	General Service Group	LPS	Lighting
Production Capacity	$83,235,507	$103,497,356	$48,681,674	$1,188,029
Production Energy	$75,592,524	$113,526,580	$58,337,132	$2,906,120
Production O&M	$49,684,134	$74,195,603	$35,653,031	$2,645,615
Transmission	$23,194,597	$26,427,255	$11,180,151	$347,514
Distribution	$66,425,670	$57,758,088	$15,408,914	$1,248,480
Customer & Uncollectables	$35,043,973	$4,410,195	$8,414	$401,660
Lighting	$0	$0	$0	$2,809,918

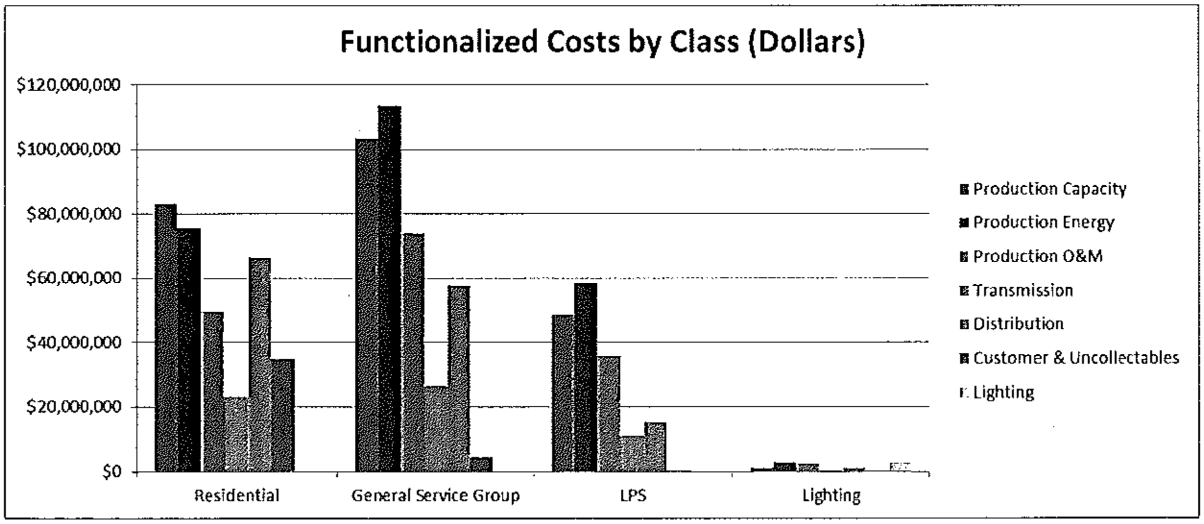
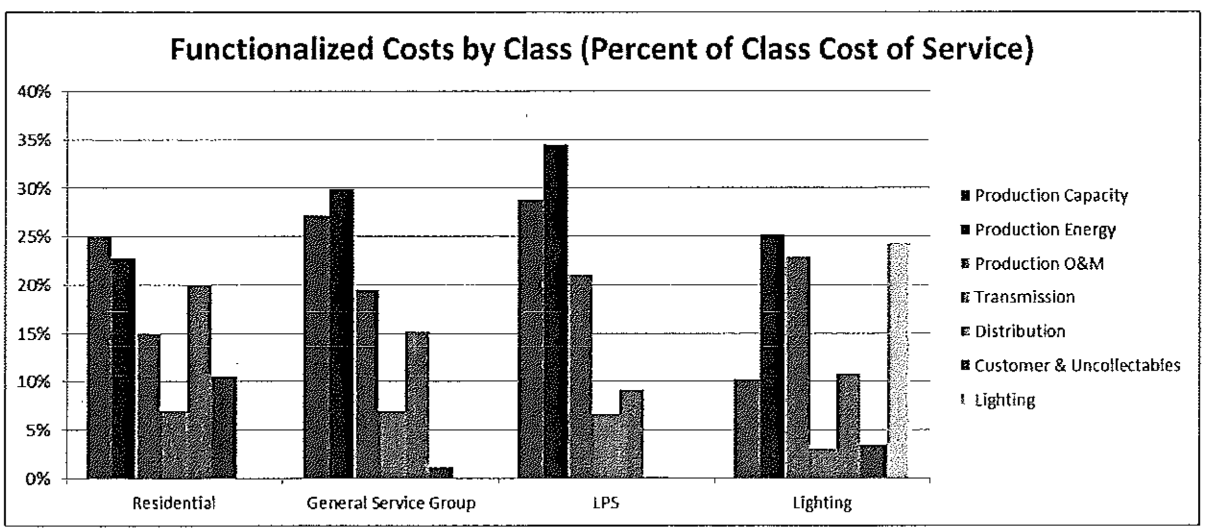


Table 5

Functionalized Costs by Class (Percent)				
	Residential	General Service Group	LPS	Lighting
Production Capacity	25%	27%	29%	10%
Production Energy	23%	30%	34%	25%
Production O&M	15%	20%	21%	23%
Transmission	7%	7%	7%	3%
Distribution	20%	15%	9%	11%
Customer & Uncollectables	11%	1%	0%	3%
Lighting	0%	0%	0%	24%



Staff Experts/Witnesses: Sarah Kliethermes and Robin Kliethermes

C. Allocation of Production Costs

For CCOS purposes, Staff assumes that the Missouri-allocated portions of all of KCPL's generation facilities are primarily used to produce electricity for KCPL's retail customers. KCPL's costs for plant investment and the production expenses appearing on its income statement are appropriately allocated by a production-capacity (demand) or a production-energy (energy) allocator. KCPL's generation facilities are predominantly considered fixed assets, and so the costs of these assets are considered demand-related and apportioned to the rate classes on the basis of the production-capacity allocator. Fuel expense related to running the generation plants and net purchased power used to serve load are considered energy-related and allocated to rate classes on the basis of the production-energy allocator. The demand and energy characteristics of KCPL's load requirement are both important determinants of production cost and expense allocations, since load must be served efficiently over time throughout the day and year.

To establish class revenue responsibilities for production costs and expenses, Staff relied on assumptions about the relationship between KCPL's generation fleet characteristics and its load characteristics. KCPL has a relatively low proportion of small coal units and combined cycle units to its total generation capacity. These are the physical plant types assumed to serve intermediate load both as a practical matter and under the BIP method as described in the NARUC Manual. To ultimately reasonably allocate all production-related costs, Staff has developed a method to reasonably assign KCPL's generation assets to the BIP components for purposes of developing allocators. In practice, because KCPL participates in the Southwest Power Pool's Day-Ahead, Real-Time, and Ancillary Services integrated markets ("SPP IM"), its generation is dispatched as part of the larger SPP fleet. SPP's dispatch is ordered according to security-constrained economic merit, which results in price signals stacking in a manner consistent with those experienced by a utility with a generation fleet that includes the relative amounts of each base, intermediate, and peak generation units assumed in the NARUC Manual. Unlike other common CCOS methods, Staff's BIP method most reasonably assumes that some plants will run virtually year round (Base), only part of the year (Intermediate), and rarely during the year (Peak). The BIP method also recognizes the fact that Base plants tend to be more expensive to install, but with a lower average cost of energy, while Peak plants tend to be less expensive to install, but with a high average cost of energy, and that Intermediate (and intermediate surrogate) plants tend to be somewhere between the two.

Staff's application of the BIP method takes into consideration the differences in the capacity/energy cost trade-off that exists across a company's generation mix, giving weight to both considerations. Because it reasonably allocates the investment and expenses of KCPL's generation fleet among the retail classes, Staff recommends using these BIP allocation factors to reasonably allocate the return on production related plant investment and production related expenses to the retail classes.

KCPL's generation fleet characteristics

KCPL's non-renewable, "Base"-designated, generating plants are the Wolf Creek nuclear unit, the Iatan Unit 2 supercritical coal plant, and the Iatan Unit 1, Hawthorn 5, and La Cygne Units 1 & 2 coal plants.[7] Staff determined that the average capacity cost, net of depreciation reserve, for KCPL's Base generation is approximately $897,096/MW. However,

[7] These types of units tend to be ideal for meeting the around-the-clock capacity needs; however, they are slow-ramping and cannot quickly react to changes in the level of demand. These units can be ramped as needed to provide regulating services to SPP, but aside from this sort of ancillary service activity, Staff would expect these plants to be "price takers" in the SPP market. KCPL also has wind investment, and wind and hydroelectric PPAs. Staff did allocate these expenses and costs to the classes using the BIP allocators; however, Staff did not assign these expenses and costs in allocator development

Staff found that the average fuel cost for these plants was only $24.68/MWh. Taken together, KCPL's Base generation ran at a 72% capacity factor in Staff's fuel model.

KCPL's "Intermediate" generating plants are the combined-cycle unit at the Hawthorn site (Unit 9 Heat Recovery Steam Generator "HRSG", fired by Unit 6 Combustion Turbine "CT"), and the units at Montrose.[8] Staff determined that the average capacity cost, net of depreciation reserve, for KCPL's Intermediate generation is approximately $281,180/MW, and the average fuel cost for these plants was $39.00/MWh. Taken together, KCPL's Intermediate generation ran at a 30% capacity factor in Staff's fuel model.

KCPL's "Peaking" generating plants that ran in Staff's fuel model are the West Gardner and Osawatomie simple-cycle gas combustion turbines.[9] Staff determined that the average capacity cost, net of depreciation reserve, for KCPL's Peaking generation is only approximately $243,041/MW. However, Staff found that the average fuel cost for these plants was $97.81/MWh. Taken together, KCPL's Peaking generation that did run in Staff's fuel model ran at a 0.16% capacity factor.

KCPL's load characteristics

The interaction of class energy requirements over the course of a year is generally studied in terms of class coincident and non-coincident peak demands. Coincident-peak demand is the demand of each customer class and each customer at the hour when the overall

[8] These units can be dispatched to meet the changing system demand in a matter of hours, and are capable of operating at high capacity factors. However, as a practical matter, these units are rarely operated at a high capacity factor, because the role of intermediate units to the generation fleet is to meet the demand requirements of load that occur often, but not constantly. Intermediate units can be dispatched in the SPP to follow load and to provide regulating reserves, but given current gas prices, it would not be surprising if these units were offered into the SPP as price takers.

[9] Gas combustion turbines are quick ramping, and because they can be cold-dispatched quickly, they are ideal for meeting spiky changes in the level of load – for example – when air conditioners fire on as a heat wave moves into an area. Gas combustion turbines are capable of high capacity factors, but tend to have the lowest capacity factors of any units, as operated. However, because KCPL participates in the SPP IM; its generation is dispatched as part of the larger SPP fleet, so its combustion turbines may be dispatched at night to assist in wind integration, as opposed to operating at times of peak demand when another utility may have less expensive energy available.

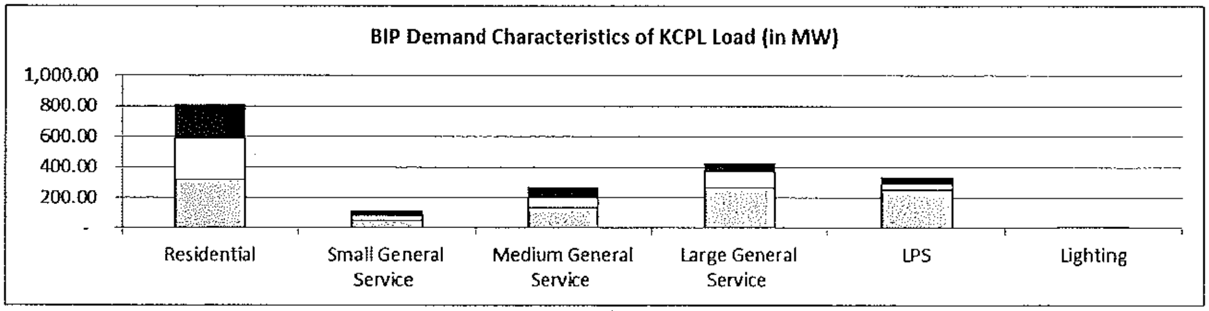
system peak occurs. Coincident-peak demand reflects the maximum amount of diversity because most customer classes are not at their individual class peaks at the time of the coincident peak. Class peak demand, which is the maximum hourly demand of all customers within a specific class, often does not 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 demand. Therefore, class-peak demand will have less diversity than the class' load at the time of system peak.

Finding Class Demands

1. Staff found each class' average demand in MW. That MW of demand value is the "base demand" used for each class in the BIP calculation.
2. Staff found each class' demand in MW at the time of each month's system peak. Staff then averaged each class' 12 demands to a single MW value. That additional MW value over the base demand MW value is each class' intermediate demand. The difference between each class' base demand and its intermediate demand is its incremental peak demand.
3. Staff found each class's demand in MW at the time of the four system peaks. Staff then averaged each class' 4 demands to a single MW value. That MW value is each class' peak demand. The difference between each class' intermediate demand and its peak demand is its incremental peak demand.

The BIP Demand Characteristics of each class (in MW) are provided in the table and graph below:

	Residential	Small General Service	Medium General Service	Large General Service	LPS	Lighting
Base Demand	316.94	50.69	135.27	266.39	253.14	10.44
Incremental Intermediate Demand	272.36	31.35	65.72	106.13	39.87	-
Incremental Peak Demand	214.77	28.25	65.32	49.79	38.48	-

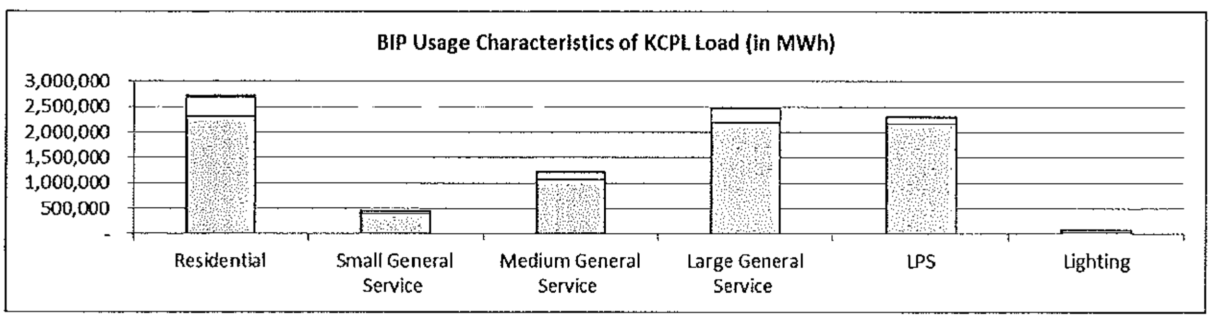


Finding Class Energy Usage

1. Staff analyzed each class' weather-normalized energy usage for each hour of the year. In a given hour, if a class had energy usage (MWh) equal to or below its base demand (MW), then Staff recorded that energy usage as base usage. If in that hour a class had energy usage in excess of its base demand, Staff recorded that hour's energy usage for that class as being equal to that class' base demand.
2. Staff then analyzed if in each hour a class had energy usage in excess of its intermediate demand. If so, Staff recorded that hour's energy usage (less the previously allocated base usage) for that class as being equal to that class' intermediate demand.
3. Finally, Staff recorded all energy usage in excess of a particular class's intermediate demand as peak usage.

The BIP Energy Characteristics of each class (in MWh) are provided in the table and graph below:

	Residential	Small General Service	Medium General Service	Large General Service	LPS	Lighting
Base Energy	2,307,885.52	395,039.28	1,073,841.95	2,195,712.13	2,173,364.27	47,020.15
Intermediate Energy	382,691.49	54,226.85	138,340.61	269,605.72	126,112.58	48,131.02
Peak Energy	48,684.87	5,238.34	20,863.97	16,931.01	25,041.59	-



Calculating BIP Allocators

The BIP method is described in the NARUC ELECTRIC UTILITY COST ALLOCATION MANUAL ("NARUC Manual"), in Part IV, C, Section 2.[10] Staff developed production-capacity and production-energy allocators by matching the average capacity cost of each with the BIP demands of each customer class, and by matching the average energy cost of each with the BIP energy requirements of each class.

Staff relied on the demand characteristics of each customer class to appropriately assign (1) the relatively expensive capacity costs of base generation on each class' base level of demand, (2) the relatively moderate capacity costs of intermediate generation on each class' intermediate level of demand, and (3) the relatively inexpensive capacity costs of peaking generation on each class' peak level of demand. Under this approach, KCPL's net investment in each of the plants assigned to each of the BIP components is allocated to the classes based on each class' base, intermediate, and peak demand (in MW). The relative value – by class – of the investment allocated to each class is used as the Production-Capacity allocator.[11]

Staff relied on the energy characteristics of each customer class to appropriately assign (1) the relatively inexpensive fuel costs of base generation on each class' base energy usage, (2) the relatively moderate fuel costs of intermediate generation on each class' intermediate energy usage, and (3) the relatively expensive fuel costs of peaking generation on each class' peak energy usage. The fuel cost on a per MWh basis for each plant, as used in the Staff revenue requirement, is used as the price to serve each class' base, intermediate, and peak

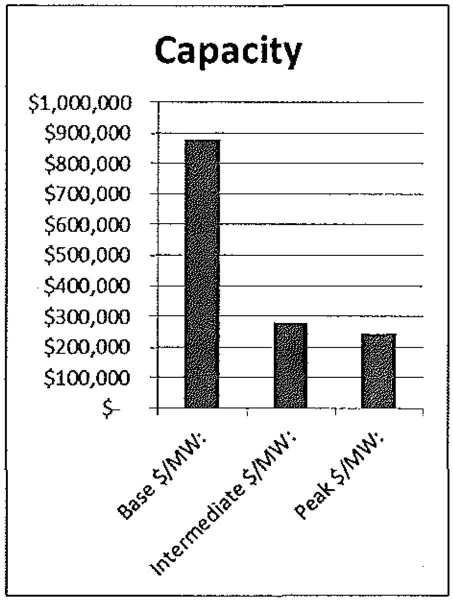
[10] Schedule CCOS-2 details the BIP method as described in the NARUC Manual, as published, January 1992.
[11] A separate capacity-related allocator is used to allocate the return on investment associated with fuel stored at the various generation stations.

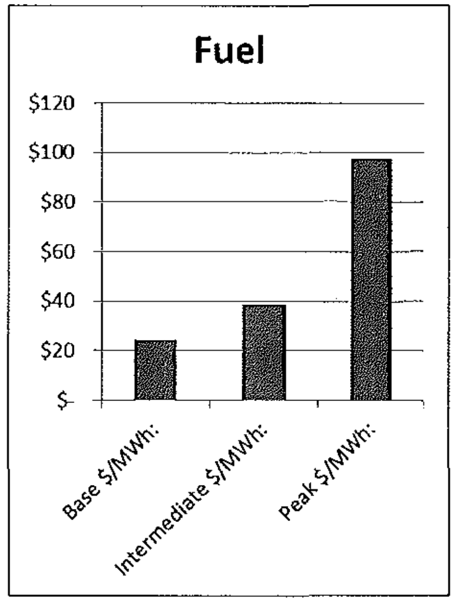
load (in MWh). The relative value – by class – of the fuel to serve the load requirements of each class is used as the Production-Energy allocator.[12]

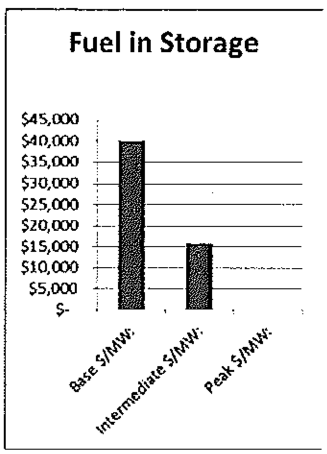
Staff also used the assignments of generating plant to BIP components to develop allocators for KCPL's production-related operating and maintenance expense, and fuel stored on site. This method expressly assigns the expenses of each plant to follow that plant. Production plant operating and maintenance expenses are caused by each of the generating plants. Staff found the level of expense for each plant assigned under the BIP components, and developed allocation factors to apply to all production-related O&M based on each customer class' proportionate share of plant responsibility assigned as described above. Similarly, fuel stored at each plant is associated with particular plants, so Staff has developed factors to allocate the fuel associated with particular plants with the plant allocated to each customer class.

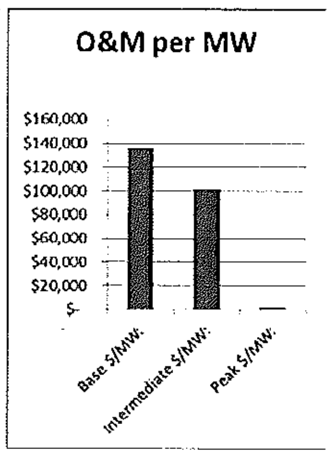
Staff's detailed BIP study reasonably balances the offsetting impacts of the relative costs of energy, capacity, O&M, and fuel-in-storage associated with meeting the demand and usage characteristics of KCPL's load. Thus, Staff BIP method is a reasonable method for allocating the production-related costs and expenses, as well as the capacity-related and energy-related portions of off-system sales revenues. This consistency is appropriate as production plant expenses and production plant investment are interrelated. The relative values of each of these items are indicated in the graphs provided below.

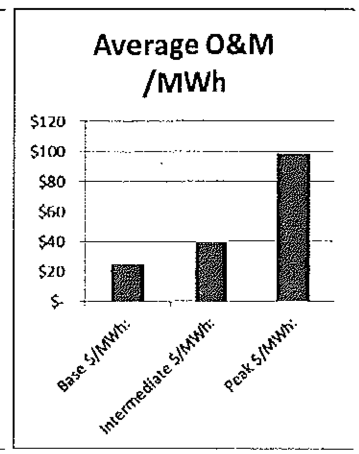
[12] A separate energy-related allocator is used to allocate the operations and maintenance expense associated with each of the various generation stations.



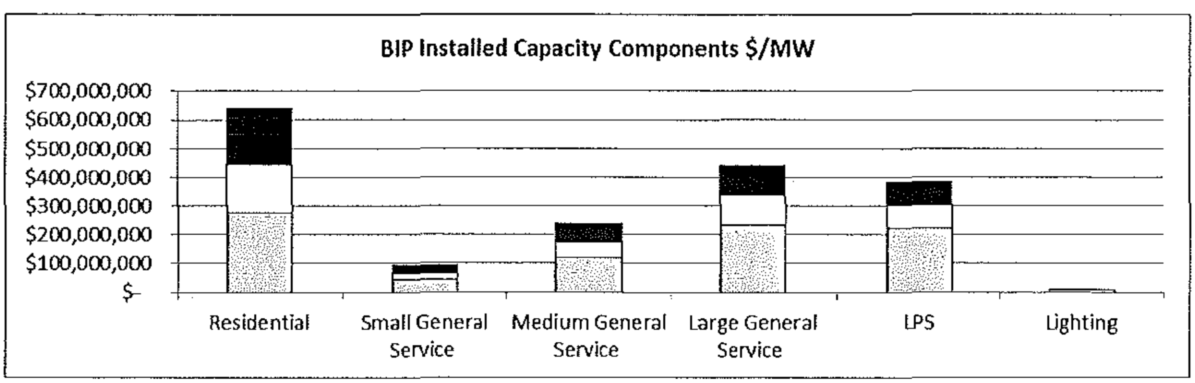




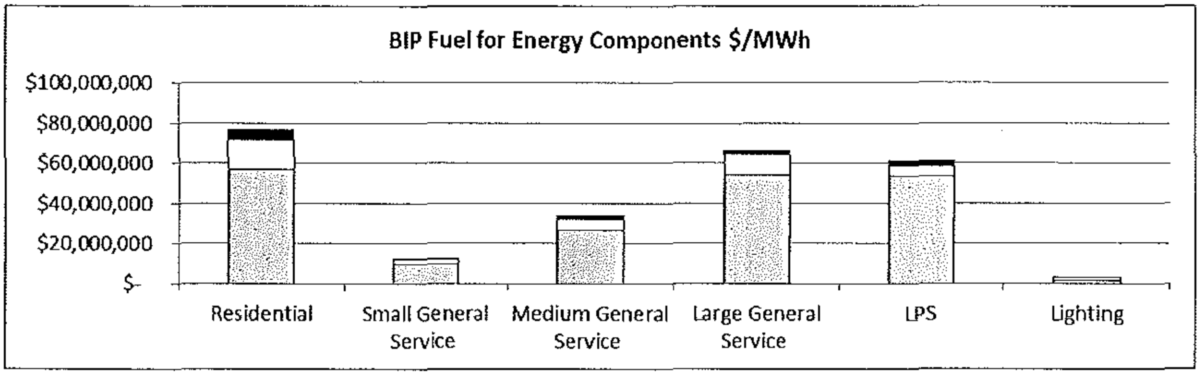




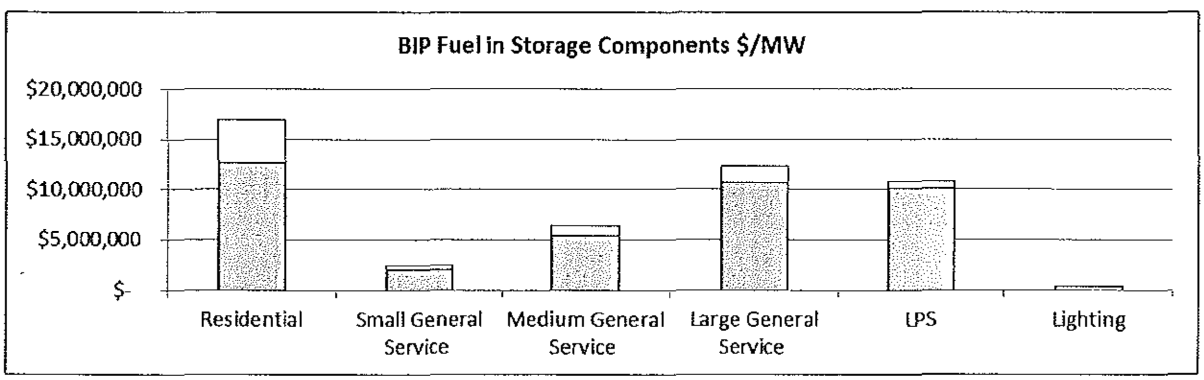
The allocators that result from applying these values to KCPL's BIP load characteristics are provided in the graphs and tables below.



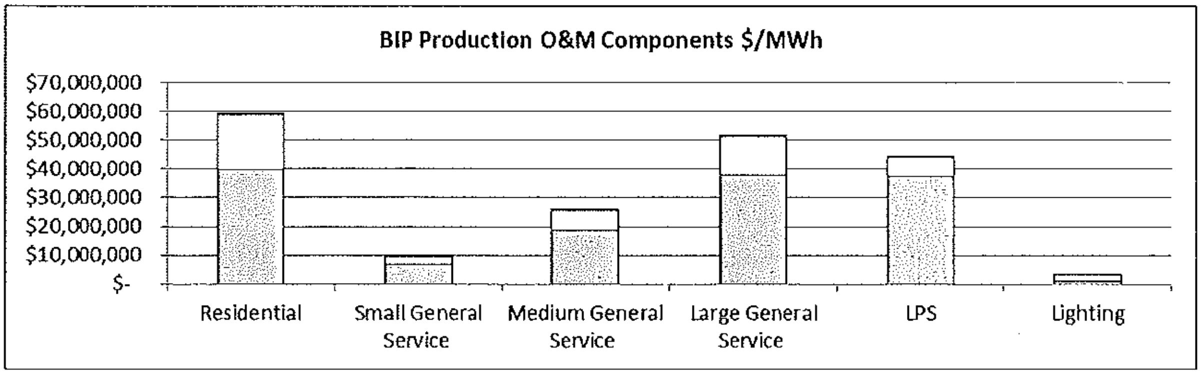
BIP Installed Capacity Allocator							
	Total	Residential	Small General Service	Medium General Service	Large General Service	LPS	Lighting
Base Capacity	$ 907,993,723	$ 278,623,348	$ 44,557,864	$ 118,917,964	$ 234,179,767	$ 222,537,018	$ 9,177,763
Incremental Intermediate Capacity	$ 432,418,883	$ 165,700,165	$ 23,067,477	$ 56,515,571	$ 104,745,318	$ 82,390,353	$ -
Incremental Peak Capacity	$ 470,158,286	$ 195,422,560	$ 26,805,525	$ 64,725,091	$ 102,638,580	$ 80,566,530	-
Totals:	$ 1,810,570,892	$639,746,073	$94,430,865	$240,158,625	$441,563,665	$385,493,901	$9,177,763
	BIP Installed Capacity Allocator:	35.33%	5.22%	13.26%	24.39%	21.29%	0.51%



BIP Fuel for Energy Allocator (annual)							
	Total	Residential	Small General Service	Medium General Service	Large General Service	LPS	Lighting
Base Energy Usage	$ 202,176,704	$ 56,952,090	$ 9,748,453	$ 26,499,383	$ 54,183,968	$ 53,632,486	$ 1,160,324
Incremental Intermediate Usage	$ 39,744,507	$ 14,924,699	$ 2,114,809	$ 5,395,187	$ 10,514,434	$ 4,918,302	$ 1,877,076
Incremental Peak Usage	$ 11,419,885	$ 4,761,705	$ 512,344	$ 2,040,636	$ 1,655,965	$ 2,449,234	$ -
Totals:	$ 253,341,095	$76,638,494	$12,375,606	$33,935,206	$66,354,367	$61,000,022	$3,037,400
	BIP Fuel for Energy Allocator:	30.25%	4.88%	13.40%	26.19%	24.08%	1.20%



BIP Fuel in Storage Allocator							
	Total	Residential	Small General Service	Medium General Service	Large General Service	LPS	Lighting
Base Capacity	$ 41,402,190	$ 12,704,511	$ 2,031,725	$ 5,422,355	$ 10,677,998	$ 10,147,118	$ 418,483
Incremental Intermediate Capacity	$ 8,087,756	$ 4,273,595	$ 491,945	$ 1,031,231	$ 1,665,337	$ 625,649	$ -
Incremental Peak Capacity	$ -	$ -	$ -	$ -	$ -	$ -	-
Totals:	$ 49,489,946	$16,978,106	$2,523,670	$6,453,585	$12,343,335	$10,772,767	$418,483
	BIP Fuel in Storage Allocator (Capacity):	34.31%	5.10%	13.04%	24.94%	21.77%	0.85%



BIP O&M Allocator							
	Total	Residential	Small General Service	Medium General Service	Large General Service	LPS	Lighting
Base Usage	$ 141,343,335	$ 39,815,657	$ 6,815,220	$ 18,525,929	$ 37,880,441	$ 37,494,895	$ 811,192
Incremental Intermediate Usage	$ 51,422,178	$ 19,309,852	$ 2,736,179	$ 6,980,392	$ 13,603,769	$ 6,363,390	$ 2,428,596
Incremental Peak Usage	$ 969,084	$ 404,075	$ 43,477	$ 173,167	$ 140,524	$ 207,841	$ -
Totals:	$ 193,734,597	$59,529,584	$9,594,877	$25,679,488	$51,624,734	$44,066,126	$3,239,788
BIP O&M Allocator (Energy):		30.73%	4.95%	13.25%	26.65%	22.75%	1.67%

Staff Experts/Witnesses: Sarah Kliethermes and Robin Kliethermes

D. Allocation of Transmission Costs

The transmission system moves electricity, at a very high voltage, from generating plants over long distances to local service areas. Transmission costs consist of costs for high voltage lines and transmission substations, and labor to operate and maintain these facilities. KCPL's transmission investment and transmission costs comprise approximately 7% of the functionalized investment and costs Staff allocated to KCPL's customer classes. KCPL's transmission system consists of highly integrated bulk power supply facilities, high voltage power lines, and substations that transmit power to other transmission or distribution voltages. Staff allocated transmission investment and costs to the customer classes based on each class' 12 CP.[13] 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

[13] Coincident peak refers the load of each class at the time of the system peak. A 12 CP is the average of each class' load at the times of the system peak for each of the 12 months of the year.

year, it takes into account the need for a transmission system that is designed both to transmit electricity during peak loads and to transmit electricity throughout the year.

Staff Experts/Witnesses: Sarah Kliethermes and Robin Kliethermes

E. Allocation of Distribution and Customer Service 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 customers' homes or businesses. A utility's distribution plant includes distribution substations, poles, wires, and transformers, 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 each class's annual non-coincident peak to allocate substation costs.[14]

KCPL divided the cost of poles, towers, fixtures; and overhead ("OH") and underground ("UG") distribution lines, conductors, and conduit between primary and secondary voltage. Staff relied on this information to also divide the distribution investment categories between primary and secondary voltage.

[14] Staff was only able to determine each class' NCP and CP at meter and at generation. It was not possible from the hourly load data used to develop class non-coincident peaks and coincident peaks to find each class' NCP and CP at the different voltage levels.

Staff allocated the costs of the primary distribution facilities on the basis of each customer class' annual non-coincident peak demand measured at the class meter. 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 allocated the costs of secondary distribution on the basis of each customer class' annual non-coincident peak demand at meter, weighting that class demand by the number of secondary distribution customers per class. Since the hourly class load data provided by KCPL was of limited quality, Staff could only determine each class' NCP and CP at meter or at generation, and not at the substation, primary, and secondary voltages that Staff typically uses for developing allocators. Staff attempted to weight each class' NCP at meter to account for the absence of primary voltage customers in allocating secondary distribution costs. Staff allocated the cost of line transformers on the same basis as secondary distribution.[15]

Staff recommends allocating costs for service drops and meter costs using data provided in KCPL's workpapers relating to the specific level of investment per class. Also, Staff recommends using KCPL's data for allocating meter reading costs, uncollectible accounts, customer services expense, and for allocating customer deposits. These allocators are derived using KCPL studies that directly assign the costs of meter reading, uncollectible accounts, customer service expense, and customer deposits to each customer class.[16] The allocators are the fraction of total costs in these accounts assigned to each class, respectively.

Staff Expert/Witness: Robin Kliethermes

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[15] Customer maximum daily demands (MDDs) were unable to be calculated in this case due to data constraints; therefore Staff used the same allocator to allocate transformer investment as secondary distribution.

[16] Staff has reviewed the results of applying the direct assignments resulting from KCPL's study. Because these results appear reasonable, Staff accepts KCPL's direct assignments of customer-related costs for CCOS purposes.

F. Revenues

Operating revenues consist of (1) the revenue that a utility collects from the sale of electricity to Missouri retail customers ("rate revenue") and (2) the revenue it receives for providing other services ("other revenue"). Rate revenues are also used in developing Staff's rate design proposal, and will be used to develop the rate schedules required to implement the Commission's ordered revenue requirement and rate design for KCPL in this case. The normalized and annualized class rate revenues in Staff's COS Report filed April 3, 2015, were used in Staff's CCOS Study.

Other Electric Revenues were allocated to the rate classes depending on the source of those revenues. KCPL was a net purchaser of off-system energy from the SPP IM in some hours in Staff's direct fuel run and a net purchaser in other hours. In The Empire District Electric Company's and Union Electric Company d//b/a Ameren Missouri's pending general electric rate cases, Case Nos. ER-2014-0351 and ER-2014-0258, respectively, Staff recommended that the fuel-related portions of off-system sales revenues be re-allocated to the classes and then the remaining off-system sales margin revenue be allocated to the classes consistent with the allocation of the production plant used to generate those sales. Staff did not provide an allocation of fuel to off-system sales in its COS Report filed April 3, 2014, in this case, so for CCOS purposes, all off-system revenues from the sale of energy through the IM were allocated on dollar-weighted energy, and all other off-system sales revenues, such as revenues from the sale of energy pursuant to firm capacity contracts, were allocated on dollar-weighted capacity. This treatment is appropriate because, since these revenues are enabled by KCPL's investment in generation capacity, it is appropriate to allocate these revenues to the retail classes consistent with the allocation of capacity costs, using the BIP Production-Capacity allocator.

Because these values are imported as separate line items into the CCOS software, it was not necessary to develop a weighted off-system sales allocator to weight the fuel-related and capacity-related components of off-system sales.

Finally, Staff's revenue requirement recommendation presented in its COS Report included a line item adjusting Staff's overall recommendation for the expected changes in cost of service that will occur if the costs of the La Cygne environmental retrofit project are included in Staff's true-up revenue requirement. Staff's CCOS software was unable to detect this additional line item, so for CCOS purposes only, this increase to cost of service is treated as a negative revenue adjustment. This amount consists almost entirely of an estimate for the La Cygne plant additions and associated depreciation expense, and is appropriately allocated using the Production-Capacity allocator.

Staff Experts/Witnesses: Sarah Kliethermes and Robin Kliethermes

G. Allocation of Taxes

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

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

Staff estimated income tax liability separately for each customer class as a function of the return-based revenues provided by each customer class. Staff has allocated KCPL's income taxes based on class earnings.

Staff Expert/Witness: Robin Kliethermes

H. Allocation of Seasonal Energy Costs

KCPL's rates are seasonal in that certain charges differ for summer versus non-summer billing months. To allocate energy-related costs by season, Staff found the ratio of summer-to-non-summer energy cost for each class. Staff found this ratio by applying each class' annual normalized load to the market costs of energy used in Staff's production cost modeling for that applicable hour. Staff then found the percentage of market energy cost for each class that was incurred during the summer billing months.

Staff Experts/Witnesses: Sarah Kliethermes and Robin Kliethermes

IV. Rate Design

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

- Provide the Commission with a rate design recommendation based on each customer class' 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; and
- Ensure KCPL receives an amount above its marginal costs on sales of electricity, and each class is providing a contribution to cover fixed costs.

Staff's rate design recommendations in this case are:

1. Based on CCOS results, Staff recommends an increase/decrease to the current base revenue on a revenue-neutral basis to various classes of customers. At this time, Staff is not recommending any revenue-neutral adjustments to any class as each class would be close to Staff's CCOS study results within a realm of reasonableness range. The revenue neutral shifts can be determined by subtracting the overall estimated 11.44% revenue increase from each class's calculated percentage change in revenues. On a revenue neutral basis, the following shifts are calculated: Res, 0.97%; general service class's combined (SGS, MGS, LGS), -3.36%; LPS, 4.94%; and lighting, -1.33%.
2. Staff determined the amount of revenue responsibility increase to award to each KCPL class based on Staff's estimated mid-point revenue requirement recommendation. Staff further recommends that an additional constraint (revenue requirement after true-up) be placed to ensure no class receives an overall reduction in its rate revenue responsibility while another class receives an overall increase in its rate revenue responsibility.

3. Staff recommends the first energy block rate of the frozen winter All-Electric Service rate schedules for the SGS, MGS, and LGS rate classes be increased by an additional 5%[17]. This is further discussed in the rate design section of Staff's CCOS Report and in Schedules MSS-D6, MSS-D7, and MSS-D8.
4. Staff recommends that each rate component of each class be increased across-the-board for each class on an equal percentage basis after applying steps 1 through 3 above. Staff recommends that, based on its CCOS study results and policy considerations, the residential and all other customer charges increase by the average increase for each applicable class.

Residential Rate Structure Change Recommendation

Outlined in Schedule MSS-5 are Staff's recommended residential rate structure changes for KCPL's Res class and rate components. As outlined in Schedule MSS-D5, ResA and ResC have an energy charge rate for the first 600 kWh, an energy charge rate for the next 400 kWh, and an energy charge rate for over 1,000 kWh, for both the winter and summer season. ResB has an energy charge rate for the first 1,000 kWh, and an energy charge rate for over 1,000 kWh. Staff recommends a rate structure change to make ResB consistent with ResA and ResC for both the summer and winter seasons. Staff notes that the current rate energy charge for the summer season[18] is the same for ResA, ResB, and ResC. The current energy charge differences are in the winter season.

KCPL's Current Rate Schedules

Residential rate schedules include:

- Residential General Use Rate Schedule
- Separate All Electric Rate schedules (one or two meters)
- Residential Time of Day rate schedule
- Residential Other Use
- Residential Time of Use Smart Grid Demonstration

[17] 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.
[18] Energy charge rate for summer is $0.1217.

The rate structure included on the residential rate schedules listed above consists of a combination of the following rate components:

- Customer Charge
- Energy Charge – per kWh per season

Commercial and industrial rate schedules consist of the following rate classifications and rate schedules:

- SGS rate schedules (secondary, primary, secondary all electric-frozen, primary all electric-frozen)
- MGS rate schedules (secondary, primary, secondary all electric-frozen, primary all electric-frozen)
- LGS rate schedules (secondary, primary, secondary all electric-frozen, primary all electric-frozen)
- LPS rate schedules (secondary, primary, substation, transmission)
- Two Part – Time of Use rate schedule

The rate structures included on the rate schedules listed above consist of a combination of the following rate components:

- 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 rate revenue is 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).

Schedules MSS-D2 through MSS-D7 attached to this report are Staff's rate design schedules. Schedule MSS-D2 details KCPL rate schedules as provided in KCPL Minimum Filing requirements. It lists the applicable class, tariff description, rate designation, tariff sheet number, average number of customers, mega-watt hour ("MWh") sales and base revenue based on KCPL's direct filing. This information is helpful in identifying the rate designation and tariff sheet number for the approximately sixty-eight rate schedules KCPL currently has.

Schedule MSS-D3 is a summary of Staff's CCOS study results for the six (6) rate classes. These also relate to the approximately 68 rate schedules. It details Staff CCOS study results (increase/decrease) amounts and percent increase/decrease based on Staff's estimated mid-point revenue requirement recommendation.

Schedule MSS-D4 is to illustrate Staff's four-step process to increase KCPL retail rate schedules, including new pre-MEEIA rates, by class. This details that Staff is not recommending any class revenue shifts, and that each class would receive the system average increase.

Schedule MSS-D5 is Staff's analysis of the Res class rate structure recommendation to bring ResA, ResB, and ResC rate classifications consistent with each other. Staff is recommending that ResB rate structure be the same as ResA and ResC.

Schedule MSS-D6 shows Staff's analysis for the SGS class, where there are rate differences between the standard SGS rate schedules and the frozen SGS rate schedules. The frozen SGS-All Electric rate classification is restricted and only available to current customers' physical locations currently taking service under the rate schedule and who are served continuously thereafter. This shows that the customer charges have the same rate, facilities charges have the same rate, the three step summer energy charges have the same rate, but there is a difference in the three–step winter energy rates. Staff is recommending that the winter first block energy charge be increased by an additional 5% to bring the frozen SGS rate component closer to the existing standard rate.

Schedule MSS-D7 shows Staff's analysis for the MGS class where there are rate differences between the standard MGS rate schedules and the frozen MGS rate schedules. The frozen MGS-All Electric rate classification is restricted and only available to current customers' physical locations currently taking service under the rate schedule and who are served continuously thereafter. This shows that the customer charges have the same rate, facilities charges have the same rate, the three step summer energy charges have the same rate, but there is a difference in the three–step winter energy rates. Staff is recommending that the winter first block energy charge be increased by an additional 5% to bring the frozen MGS rate component closer to the existing standard rate.

Schedule MSS-D8 shows Staff's analysis for the LGS class where there are rate differences between the standard LGS rate schedules and the frozen LGS rate schedules. The frozen LGS-All Electric rate classification is restricted and only available to current customers' physical locations currently taking service under the rate schedule and who are served continuously thereafter. This shows that the customer charges have the same rate, facilities charges have the same rate, the three step summer energy charges have the same rate, but there is a difference in the three–step winter energy rates. Staff is recommending that the winter first block energy charge be increased by an additional 5% to bring the frozen LGS rate component closer to the existing standard rate.

Staff Experts/Witnesses: Michael Scheperle and Robin Kliethermes

V. Residential Customer Charge

Based on Staff's CCOS study results and rate design principles regarding rate simplicity, stability, and customer understandability, Staff recommends that the residential customer charge increase by the same percentage increase as the energy charges for the Residential Service class.[19] Using Staff's recommended revenue requirement and rate design proposal, which includes a true-up estimate, this would be an 11.44% or approximately $1.00 increase in the residential customer charge at the time of this filing.[20]

Costs included in the calculation of the residential customer charge are the costs necessary to make electric service available to the customer, regardless of the level of electric service utilized. Examples of such costs include monthly meter reading, billing, postage, customer accounting service expenses, as well as a portion of the costs associated with the required investment in a meter, the service line ("drop"), and other billing costs. The costs included for recovery through the customer charge consist of the following:

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[19] KCPL's current residential customer charge is $9.00 for customers with a single meter.
[20] The amount of the increase in the residential customer charge will vary with any approved interclass shifts and the level of overall system average increase.

- Distribution – services (investment and expenses);
- Distribution – meters (investment and expenses);
- Distribution – customer installations;
- Customer deposit;
- Customer meter reading;
- Other customer billing expenses;
- Uncollectible accounts (write-offs);
- Customer service & information expenses;
- Sales expense; and
- Portion of income taxes.

Staff recommends allocating costs for service drops and meter costs using data provided in KCPL's workpapers relating to the specific level of investment per class. Also, Staff recommends using KCPL's data for allocating meter reading costs, uncollectible accounts, customer services expense, and for allocating customer deposits. These allocators are derived using KCPL studies that directly assign the costs of meter reading, uncollectible accounts, customer service expense, and customer deposits to each customer class.[21] The allocators are the fraction of total costs in these accounts assigned to each class, respectively. The sum of the residential class' costs allocated to the customer charge determines a residential monthly customer charge sufficient to collect those costs from the customers within the class. Staff's CCOS study and calculation of the residential customer charge resulted in a customer charge of approximately $16.49 per month. However, weighing the factors of rate simplicity, stability, customer understandability, and public policy

[21] Staff has reviewed the results of applying the direct assignments resulting from KCPL's study. Because these results appear reasonable, Staff accepts KCPL's direct assignments of customer-related costs for CCOS purposes.

consideration relating to energy efficiency, Staff recommends limiting the residential customer charge to the level of the average residential class increase.[22]

Staff Expert/Witness: Robin Kliethermes

VI. Commercial and Industrial Customer Charges

Based on Staff's CCOS study results and policy considerations, Staff recommends that the commercial and industrial customer charges be increased by the system average increase for those classes.

Staff calculated commercial and industrial customer charges using the same methodology as discussed above in Staff's calculation of the residential customer charge.

Similar to the calculation of the residential customer charge the costs included for recovery through the customer charge consist of the following:

- Distribution – services (investment and expenses);
- Distribution – meters (investment and expenses);
- Distribution – customer installations;
- Customer deposit;
- Customer meter reading;
- Other customer billing expenses;
- Uncollectible accounts (write-offs);
- Customer service & information expenses;
- Sales expense; and
- Portion of income taxes.

Staff Expert/Witness: Michael Scheperle

[22] In the last Union Electric Company d/b/a Ameren Missouri rate case, Case No. ER-2012-0166, the Commission found that there were strong public policy considerations in favor of not increasing the customer charges, particularly, that a lower customer charge enables customers to see greater impact from conservation efforts and therefore encourages customers to engage in conservation efforts. In that case, the Commission rejected a proposed increase to the residential customer charge, noting that increasing the customer charge would send exactly the wrong message to customers and would discourage efforts to conserve electricity. The same concern is raised in considering raising the residential customer charge in this case. Any increase to the residential customer charge would slightly decrease the bill impact (and cost-effectiveness) of any conservation efforts that customers may have implemented or be considering.

VII. Fuel Adjustment Clause ("FAC") Rate Design

In its COS Report, filed April 3, 2015, in this case, Staff stated that it cannot support KCPL's request for a FAC in a rate case filed prior to June 1, 2015, since the Regulatory Plan approved by the Commission in Case No. EO-2005-0329 prohibits KCPL from proposing a FAC prior to June 1, 2015. Further, if the Commission determines that KCPL is permitted to propose a FAC in this case, Staff recommended that KCPL ***not*** be granted a FAC because KCPL has not met all of the three criteria for determining whether an electric utility should be allowed to implement a FAC. However, if the Commission grants KCPL's request to implement a FAC, Staff is recommending:

1. A 95/5 percent sharing mechanism;
2. Exclusion of Southwest Power Pool ("SPP") Schedules 11 and 12 costs and revenues;
3. Exclusion of SPP Schedule 1-A administrative charges; and
4. KCPL should provide additional monthly filings that will aid the Staff in performing FAC tariff, prudence and true-up reviews.

Finally, if the Commission authorizes KCPL to implement a FAC, Staff recommends a revised Base Factor ("BF")[23] in the FAC tariff sheets be calculated from the Base Energy Cost and Revenues that the Commission includes in the revenue requirement upon which it sets KCPL's general rates in this case.

Changes to Proposed Fuel Adjustment Clause Tariff Sheets

Schedule DEE-1 contains redline/strikeout exemplar tariff sheets with Staff's proposed changes to KCPL's proposed FAC tariff sheets which were filed as part of KCPL witness Tim Rush's direct testimony, in the event that the Commission grants KCPL's request to implement a FAC.

[23] Base Factor is the base energy cost divided by net generation kWh.

Base Factor

Staff recommends a BF of $0.01406 per kWh before voltage adjustments.[24] Staff used the Base Energy Costs and Revenues from Staff's accounting schedules found in Staff's COS Report to calculate the BF. Staff will update the BF before voltage adjustments as part of the test year true-up in this case. The BF Calculation Section provides the Staff's method for determining Staff's recommended BF.

95/5 Percent Sharing Mechanism

Staff is recommending a 95/5 percent sharing mechanism where KCPL's customers would be responsible for (or receive the benefit of) 95 percent of any deviation in fuel and purchased power costs from the base level set in this case and KCPL shareholders would have the responsibility for the remaining 5 percent. The Commission previously found this 95/5 percent sharing percentage to be equitable between the customers and shareholders. In the Commission's Report and Order in Case No. ER-2008-0318, on page 76, the Commission stated:

> AmerenUE's fuel adjustment charge shall include an incentive clause providing that 95 percent of any deviation in fuel and purchased power costs from the base level shall be passed to customers and 5 percent shall be retained by AmerenUE. This incentive clause will give AmerenUE a sufficient opportunity to earn a fair return on equity as required by Section 386.266 and the Hope and Bluefield decisions. At the same time, it will protect AmerenUE's customers by giving the company an incentive to be prudent in its decisions by not allowing all costs to simply be passed through to customers.

Fuel Costs Incurred to Support Sales ("FC")

Fuel costs incurred to support sales include the variable cost of fuel used in the production of electricity in FERC accounts 501, 509, 518 and 547. It also includes combustion product disposal revenues and expenses, and the expense for air quality control systems (AQCS) consumables such as ammonia, limestone, powdered activated carbon, sodium bicarbonate, sulfur, trona, urea or other consumables which perform similar functions, used to treat the air emissions from generating electricity.

FERC account 501 provides for the recording of coal costs and related coal costs. Coal is a major fuel expense and is appropriate for KCPL to seek recovery of fluctuations in its coal expense through a FAC, if a FAC is appropriate at all.[25] Staff is recommending the deletion of the term "accessorial charges" included in FERC account 501 from KCPL's proposed FAC tariff. Staff is not familiar and could not identify any references as to the nature of such costs and therefore they should be removed from KCPL's proposed FAC tariff.

FERC account 518 provides for the recording of nuclear fuel expenses. KCPL shares ownership in the Wolf Creek Nuclear generating facility and incurs nuclear fuel expense. Nuclear fuel is a major fuel expense and is appropriate for KCPL to seek recovery of its nuclear fuel expense through a FAC, if a FAC is appropriate at all. Staff is recommending costs associated FERC account 518 be included, with the exception of DOE spent nuclear fuel fees associated with the Nuclear Waste Policy Act of 1982. Staff's recommendation regarding these costs is presented in Staff's revenue requirement cost of service report.

FERC account 547 provides for the recording of "Fuel Stock" which is comprised of natural gas and fuel oil. Natural gas and fuel oil is a major fuel expense and is appropriate for KCPL to seek recovery through a FAC, if a FAC is appropriate at all. Staff is recommending costs associated with FERC account 547 be included, with the exception of costs associated with KCPL's cross hedging policy. KCPL is not currently utilizing this cross hedging strategy so this cost item should not be included for recovery through a FAC. Staff and other

[25] The Commission should keep in mind that Staff's primary recommendation is that the Commission should not grant KCPL a FAC.

parties should have an opportunity to review costs and the impact costs associated with such hedging practices may have on a FAC.

Net Emission Costs ("E")

FERC account 509 provides for the recording of "Allowances." Allowance costs are generally costs associated with NO_X and SO_2 created by the burning of fossil fuels to generate electricity. Staff is not recommending changes to this section of KCPL's proposed FAC tariff.

Purchased Power Costs ("PP")

Staff's proposed tariff sheets include the purchased power costs in FERC account 555, which includes purchased power costs from SPP's IM.[26] Staff is recommending costs associated with SPP Schedule 1-A, Tariff Administration Service, be excluded, because the intent of KCPL's FAC is not to recover administrative costs, but fluctuating fuel and purchased power costs.

Additional language has been added to this section to account for changes and additions of market settlement charge types by SPP or another market participant. KCPL may include a new charge type cost or revenue in its fuel adjustment rate ("FAR") filings if it believes the new charge type cost or revenue possesses the characteristics of the costs or revenues listed in KCPL's FAC tariff sheets. KCPL shall provide notice in its monthly reports required by the Commission's fuel adjustment clause rules and provide enough information for the transparent determination of current period and cumulative costs or

[26] Southwest Power Pool 2014 Strategic Plan, page 6; **Market Operations**: The Integrated Marketplace launched in 2014 and replaced the existing Energy Imbalance Service market. It includes a Day-Ahead Market with Transmission Congestion Rights, a Reliability Unit Commitment process, a Real-Time Balancing Market replacing the EIS Market, and the incorporation of price-based Operating Reserve procurement.

revenues. A party may challenge the inclusion, or failure to include a new charge type cost or revenue in the FAR filing.

Transmission Costs ("TC")

Staff is proposing inclusion of SPP transmission costs as recorded in FERC Account 565, net of all transmission service revenues reflected in FERC Account 456. Transmission costs are necessary to allow for the movement of electricity from point to point, and it is appropriate for KCPL to seek recovery of fluctuations in such costs through a FAC, if a FAC is appropriate at all. However, Staff is specifically recommending the exclusion of all charges and revenues associated with SPP Schedule 11,[27] "Base Plan Zonal Charge and Region-Wide Charge" and SPP Schedule 12 "FERC Assessment Charge"[28]. Staff contends the nature of these specific transmission costs are not volatile in nature and do not meet the FAC requirement[29].

Off-System Sales Revenue ("OSSR")

FERC account 447 provides for the recording of revenue associated with the sale of electricity to others. The revenue KCPL receives from these sales is significant and is used to off-set fuel costs, and it is appropriate for KCPL to seek recovery of fluctuations in OSSR through a FAC, if a FAC is appropriate at all. Staff's recommended BF includes revenues reflected in FERC account 447 for all revenues from off-system sales, but excludes revenues from full and partial requirements sales to municipalities that are served through bilateral contracts with KCPL in excess of one year's duration. The revenue from full and partial requirements contracts are included in permanent rates as determined in this rate case, as they

[27]Southwest Power Pool - Open Access Transmission Tariff, Sixth Revised Volume No. 1 - Schedule 11 Base Plan Zonal Charge and Region-wide Charge

[28]Southwest Power Pool - Open Access Transmission Tariff, Sixth Revised Volume No. 1 - Schedule 12 FERC Assessment Charge

[29]See MOPSC Rule 4 CSR 240.20.090(2)(C)

are not volatile. Staff is recommending the OSSR component include revenues from the SPP energy market: energy, ancillary services, revenue sufficiency, revenue neutrality, losses, Transmission Congestion Rights ("TCR") and Auction Revenue Rights ("ARR") settlements, and demand reduction. The revenue KCPL receives from these sales is significant, and it is used to off-set fuel costs and purchased power costs, and it is appropriate for KCPL to seek recovery through a FAC, if a FAC is appropriate at all. Staff is recommending the miscellaneous SPP IM charges language be excluded as it is not defined and does not allow for an appropriate understanding of the true nature of such items.

Renewable Energy Credit Revenue ("REC")

Staff made no changes to this section of KCPL's proposed FAC tariff.

Other Changes to KCPL's FAC Tariff Sheets

Staff made technical and grammatical suggestions throughout KCPL's proposed FAC tariff.

Additional Filing Requirements

Due to the accelerated Staff review process necessary with FAC adjustment filings,[30] Staff is recommending the Commission order KCPL to perform the following to aid the Staff in performing FAC tariff, prudence and true-up reviews:

- As part of the information KCPL submits when it files a tariff modification to change its Fuel and Purchased Power Adjustment rate, include KCPL's calculation of the interest included in the proposed rate;
- Maintain at KCPL's corporate headquarters or at some other mutually-agreed-upon place and make available within a mutually-agreed-upon time for review, a copy of each and every coal and coal transportation, natural gas, fuel oil and nuclear fuel contract KCPL has that is in or was in effect for the previous four years;
- Within 30 days of the effective date of each and every coal and coal transportation, natural gas, fuel oil and nuclear fuel contract KCPL enters into, provide both notice to

[30] The Company must file its FAC adjustment 60 days prior to the effective date of its proposed tariff sheet. Staff has 30 days to review the filing and make a recommendation to the Commission. The Commission then has 30 days to approve or deny Staff's recommendation.

the Staff of the contract and opportunity to review the contract at KCPL's corporate headquarters or at some other mutually-agreed-upon place;

- Provide a copy of each and every KCPL hedging policy that is in effect at the time the tariff changes ordered by the Commission in this rate case go into effect for Staff to retain;
- Within 30 days of any change in a KCPL hedging policy, provide a copy of the changed hedging policy for Staff to retain;
- Provide a copy of KCPL's internal policy for participating in the Southwest Power Pool's Integrated Market;
- Maintain at KCPL's corporate headquarters or at some other mutually-agreed-upon place and make available within a mutually-agreed-upon time for review, a copy of each and every bilateral energy or demand sales/purchase contract.
- If KCPL revises any internal policy for participating in the Southwest Power Pool, within 30 days of that revision, provide a copy of the revised policy with the revisions identified for Staff to retain; and
- The monthly as-burned fuel report supplied by KCPL required by 4 CSR 3.190(1)(B) shall explicitly designate fixed and variable components of the average cost per unit burned including commodity, transportation, emission, tax, fuel blend, and any additional fixed or variable costs associated with the average cost per unit reported (Staff is willing to work with KCPL on the electronic format of this report).

<u>Revised Base Factor Calculation</u>

Staff calculated the BF of $0.01406 per kWh using the Base Energy Costs and Revenues from Staff's accounting schedules found in Staff's Revenue Requirement Cost of Service report in this rate case and Staff's proposed changes to the FAC tariff sheets discussed above. The BF calculation is broken down into fuel costs incurred to support sales, purchased power costs, net emission costs, revenues from off-system sales and renewable energy credit revenue.

Staff Expert/Witness: Dana Eaves

STAFF RATE DESIGN AND CLASS COST-OF-SERVICE REPORT

Class Cost-of-Service and Rate Design Overview

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

Definitions and Fundamental Concepts of Electric CCOS and Rate Design

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Electric power is produced at the generation station, transmitted some distance through high voltage lines, stepped down to secondary voltage and distributed to secondary voltage customers. Other customers (high voltage and primary voltage) are served from various points along the system.

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

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

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

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

2. Classification

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, and 3) 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 certain 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.

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.

TABLE 4-16

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

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

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

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

C. Time-Differentiated Embedded Cost of Service Methods

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

1. Production Stacking Methods

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

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

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

2. Base-Intermediate-Peak (BIP) Method

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

TABLE 4-17

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

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

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

Some columns may not add to indicated totals due to rounding

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

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

3. LOLP Production Cost Method

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

4. Probability of Dispatch Method

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

TABLE 4-18

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

	1 CP METHOD		12 CP METHOD		3 SUMMER & 3 WINTER PEAK METHOD		ALL PEAK HOURS APPROACH		AVERAGE AND EXCESS METHOD	
	Revenue Req't. ($)	Percent of Total	Revenue Req't. ($)	Percent of Total	Revenue Req't. ($)	Percent of Total	Revenue Req't. ($)	Percent of Total	Revenue Req't. ($)	Percent of Total
DOM	$ 369,461,692	34.84	$ 340,287,579	32.09	$ 388,925,712	36.67	$ 340,747,311	32.13	$ 386,682,685	36.46
LSMP	394,976,787	37.25	407,533,507	38.43	376,433,254	35.50	384,043,376	36.21	369,289,317	34.82
LP	261,159,089	24.63	283,283,130	26.71	266,582,600	25.14	299,737,319	28.26	254,184,071	23.97
AG&P	34,878,432	3.29	25,700,311	2.42	23,555,089	2.22	28,970,743	2.73	41,218,363	3.89
SL	0	0.00	3,671,473	0.35	4,978,544	0.47	6,977,251	0.66	9,101,564	0.86
Total	$1,060,476,000	100.00	$1,060,476,000	100.0	$1,060,476,000	100.00	$1,060,476,000	100.0	$1,060,476,000	100.0

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

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Information Based on Minimum Filing Requirements

Line No.	Class / Tariff	Tariff Description	Tariff Sheet	Average Number of Customers	MWH	Base Revenue
1	**Residential**					
2	RESA	Residential General Use	5A	189,323	1,868,800	$214,019,430
3	RESB	Residential General Use and Space Heat - 1 Meter	5A	41,932	570,416	$55,743,945
4	RESC	Residential General Use and Space Heat - 2 Meters	5B	10,491	162,009	$14,828,614
5	RTOD	Residential Time of Day (Frozen)	8	39	545	$59,331
6	ROU	Residential Other Use	6	45	297	$43,802
7	RTOUA	Residential Time of Use for Smartgrid Demonstration Area - General Use	43AO	100	599	$148,654
8	RTOUB	Residential Time of Use for Smartgrid Demonstration Area - General Use & Space Heat	43AP	17	193	$33,378
9		Total Residential		241,947	2,603,264	$284,877,154
10	**Small General Service**					
11	SGSS	Small General Secondary	9A	23,706	382,748	$45,437,511
12	SGSSA	Small General Secondary - All Electric (Frozen)	17A	446	15,366	$1,579,171
13	SGSSH	Small General Secondary Separate Heat Meter (Frozen)	9A	201	5,816	$625,866
14	SGSSU	Small General Secondary Unmetered		1,229	7,378	$945,387
15	SGSP	Small General Primary	9B	42	1,252	$201,319
16	SGSPA	Small General Primary All Electric (Frozen)	17A	0	0	$0
17	SGSPU	Small General Primary Unmetered		0	0	$0
18		Total Small General Service		25,624	412,560	$48,789,254
19	**Medium General Service**					
20	MGSS	Medium General Secondary	10A	4,902	970,816	$91,254,175
21	MGSSA	Medium General Secondary All Electric (Frozen)	18A	371	110,317	$9,236,935
22	MGSSH	Medium General Secondary Separate Heat Meter (Frozen)	10A	80	22,014	$1,915,224
23	MGSP	Medium General Primary	10B	36	9,396	$822,430
24	MGSPA	Medium General Primary All Electric (Frozen)	18B	1	397	$33,938
25		Total Medium General Service		5,390	1,112,940	$103,262,752
26	**Large General Service**					
27	LGSS	Large General Secondary	11A	696	1,145,019	$96,671,711
28	LGSSA	Large General Secondary All Electric (Frozen)	19A	204	643,964	$48,170,057
29	LGSSH	Large General Secondary Separate Heat Meter (Frozen)	11A	32	48,721	$4,122,805
30	LGSP	Large General Primary	11B	80	244,688	$20,002,309
31	LGSPA	Large General Primary All Electric (Frozen)	19B	14	164,418	$11,781,022
32		Total Large General Service		1,026	2,246,840	$180,747,904
33	**Large Power Service**					
34	LPGSS	Large Power General Secondary	14A	32	460,932	$32,671,644
35	LPGSPO	Large Power General Primary - Off Peak	15	10	273,694	$19,489,728
36	LPGSSS	Large Power General Service Substation	14B	3	344,253	$19,351,581
37	LPGSTR	Large Power General Transmission	14B	3	131,818	$7,850,063
38	LPSTRO	Large Power General Transmission - Off Peak	15	2	147,548	$7,925,561
39	LPGSPO	Large Power General Primary	14A	31	848,760	$57,335,492
40		Total Large Power Service		81	2,207,065	$144,684,069
41	**Other (Lighting and Traffic Signals)**					
42	ALC	Mo Commercial Area Lights	33	2,316	13,271	$2,603,617
43	ALR	Mo Residential Area Lights	33	956	903	$299,027
44	OLS	KCMO School District Parking Lot Light	45	1	646	$16,348
45	MLC, MLI, MLM, MLS	Mo Street Lighting Public & KCMO Street Lights	35,36	69	71,036	$6,703,229
46	TSL	Mo Traffic Signals	37	2	119	$51,565
47	MLL	Mo Street Lights - Municipal LED	48	1	7	$6,065
48		Total Other		3,345	85,987	$9,714,851
49		Subtotal		277,413	8,668,656	$772,075,934
50		Area Lights not included in total customer count		(3272)		
51		EDR Adjustments				($2,859,459)
52		Mpower Adjustments				($1,700,036)
53		Revenue Adjustments				($921,601)
54		**Total Retail**		**274,141**	**8,668,656**	**$766,594,888**

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Class Information

Class	CCOS Increase	Percent Increase
Residential	$35,417,070	12.41%
Small General Service	$ 920,261	1.87%
Medium General Service	$ 8,597,631	8.32%
Large General Service	$ 18,884,998	10.68%
Large Power Service	$ 22,049,532	16.38%
Lighting	$ 981,699	10.11%
Total	$86,851,191	11.44%

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Rate Design

Illustrative Purposes Only

Line No.	Class	Total Current Revenue Including Pre-MEEIA	Step 1 Revenue Shift	Adjusted Retail and Pre-MEEIA	Increase	Total Revenue Requirement	Percent Increase	Revenue Neutral
1	Res	$ 285,242,792	$ -	$ 285,242,792	$ 32,639,360	$ 317,882,152	11.44%	0.00%
2	SGS	$ 49,244,047	$ -	$ 49,244,047	$ 5,634,828	$ 54,878,875	11.44%	0.00%
3	MGS	$ 103,405,282	$ -	$ 103,405,282	$ 11,832,314	$ 115,237,596	11.44%	0.00%
4	LGS	$ 177,115,726	$ -	$ 177,115,726	$ 20,266,749	$ 197,382,475	11.44%	0.00%
5	LPS	$ 134,289,679	$ -	$ 134,289,679	$ 15,366,310	$ 149,655,989	11.44%	0.00%
6	Lighting	$ 9,714,851	$ -	$ 9,714,851	$ 1,111,637	$ 10,826,488	11.44%	0.00%
7	Total	$ 759,012,377	$ -	$ 759,012,377	$ 86,851,199	$ 845,863,576	11.44%	0.00%
8	Total Increase at Staff Mid-Point				$ 86,851,199			

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Residential Class

RESA

Residential General Use - Sheet 5A	Existing Jan 26, 2013	Residential General Use - Sheet 5A
Customer Charge	$9.00	Customer Charge
Energy Charge - Summer		**Energy Charge - Summer**
First 600 KWH	$0.12157	First 600 KWH
Next 400 KWH	$0.12157	Next 400 KWH
Over 1000 Kwh	$0.12157	Over 1000 Kwh
Energy Charge - Winter		**Energy Charge - Winter**
First 600 KWH	$0.10929	First 600 KWH
Next 400 KWH	$0.06552	Next 400 KWH
Over 1000 Kwh	$0.05475	Over 1000 Kwh

Recommended Rate Structure

RESB

Residential General Use and Space Heat - One Meter (Sheet 5A)	Existing Jan 26, 2013	Residential General Use and Space Heat - One Meter (Sheet 5A)	
Customer Charge	$9.00	Customer Charge	
Energy Charge - Summer		**Energy Charge - Summer**	
First 1000 KWH	$0.12157	First 600 KWH	**Added Step**
		Next 400 KWH	**Added Step**
Over 1000 KWH	$0.12157	Over 1000 KWH	
Energy Charge - Winter		**Energy Charge - Winter**	
First 1000 KWH	$0.08544	First 600 KWH	**Added Step**
		Next 400 KWH	**Added Step**
Over 1000 KWH	$0.05370	Over 1000 KWH	

RESC

Residential General Use and Space Heat - 2 Meters (5B)	Existing Jan 26, 2013	Residential General Use and Space Heat - 2 Meters (5B)
Customer Charge	$11.05	Customer Charge
Energy Charge - Summer		**Energy Charge - Summer**
First 600 KWH	$0.12157	First 600 KWH
Next 400 KWH	$0.12157	Next 400 KWH
Over 1000 Kwh	$0.12157	Over 1000 Kwh
Energy Charge - Winter		**Energy Charge - Winter**
First 600 KWH	$0.10929	First 600 KWH
Next 400 KWH	$0.06552	Next 400 KWH
Over 1000 Kwh	$0.05475	Over 1000 Kwh

Separately Metered Space Heat Rate - Summer	$0.12157	Separately Metered Space Heat Rate - Summer
Separately Metered Space Heat Rate - Winter	$0.05494	Separately Metered Space Heat Rate - Winter

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Small General Service

Small General Service - Rate for Service at Secondary Voltage	Existing Sheet 9A	Frozen Existing Sheet 17A	Difference	Percent
Customer Charge - Metered				
0 - 24 KW	$16.45	$16.45	$0.00	0.00%
25 - 199 KW	$45.60	$45.60	$0.00	0.00%
200 - 999 KW	$92.64	$92.64	$0.00	0.00%
1000 KW or above	$790.99	$790.99	$0.00	0.00%
Customer Charge - Unmetered	$6.90	N/A		
Customer Charge - Separately Metered Space Heat (Frozen)	$2.12	N/A		
Facilities Charge				
First 25 KW	$0.000	$0.000	$0.000	
All KW over 25 KW	$2.650	$2.650	$0.000	0.00%
Energy Charge - Summer				
First 180 Hours Use per month	$0.14682	$0.14682	$0.00000	0.00%
Next 180 Hours Use per month	$0.06966	$0.06966	$0.00000	0.00%
Over 360 Hours Use per month	$0.06207	$0.06207	$0.00000	0.00%
Energy Charge - Winter				
First 180 Hours Use per month	$0.11408	$0.09951	-$0.01457	-12.77%
Next 180 Hours Use per month	$0.05570	$0.05737	$0.00167	3.00%
Over 360 Hours Use per month	$0.05027	$0.05465	$0.00438	8.71%
Separately Metered Space Heat				
Winter Season (Sheet 9A) (Frozen)	$0.06109	N/A		

Small General Service - Rate for Service at Primary Voltage	Existing Sheet 9B	Frozen Existing Sheet 17A	Difference	Percent
Customer Charge - Metered				
0 - 24 KW	$16.45	$16.45	$0.00	0.00%
25 - 199 KW	$45.60	$45.60	$0.00	0.00%
200 - 999 KW	$92.64	$92.64	$0.00	0.00%
1000 KW or above	$790.99	$790.99	$0.00	0.00%
Customer Charge - Unmetered	$6.90	N/A		
Facilities Charge				
First 26 KW	$0.000	$0.000	$0.000	0.00%
All KW over 26 KW	$2.588	$2.588	$0.000	0.00%
Energy Charge - Summer				
First 180 Hours Use per month	$0.14346	$0.14346	$0.00000	0.00%
Next 180 Hours Use per month	$0.06807	$0.06807	$0.00000	0.00%
Over 360 Hours Use per month	$0.06063	$0.06063	$0.00000	0.00%
Energy Charge - Winter				
First 180 Hours Use per month	$0.11148	$0.09724	-$0.01424	-12.77%
Next 180 Hours Use per month	$0.05442	$0.05606	$0.00164	3.01%
Over 360 Hours Use per month	$0.04910	$0.05339	$0.00429	8.74%

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Medium General Service

Medium General Service - Rate for Service at Secondary Voltage	Existing Sheet 10A	Frozen Existing Sheet 18A	Difference	Percent
Customer Charge - Metered				
0 - 24 KW	$47.67	$47.67	$0.00	0.00%
25 - 199 KW	$47.67	$47.67	$0.00	0.00%
200 - 999 KW	$96.82	$96.82	$0.00	0.00%
1000 KW or above	$826.71	$826.71	$0.00	0.00%
Customer Charge - Separately Metered Space Heat (Frozen)	$2.22	N/A		
Facilities Charge				
Per KW of Facilities Demand per month	$2.770	$2.770	$0.000	0.00%
Demand Charge - Summer	$3.624	$3.624	$0.000	0.00%
Demand Charge - Winter	$1.844	$2.611	$0.767	41.59%
Energy Charge - Summer				
First 180 Hours Use per month	$0.09473	$0.09473	$0.00000	0.00%
Next 180 Hours Use per month	$0.06479	$0.06479	$0.00000	0.00%
Over 360 Hours Use per month	$0.05464	$0.05464	$0.00000	0.00%
Energy Charge - Winter				
First 180 Hours Use per month	$0.08185	$0.06840	-$0.01345	-16.43%
Next 180 Hours Use per month	$0.04899	$0.04109	-$0.00790	-16.13%
Over 360 Hours Use per month	$0.04109	$0.03568	-$0.00541	-13.17%
Separately Metered Space Heat				
Winter Season (Sheet 10A) (Frozen)	$0.05352	N/A		

Medium General Service - Rate for Service at Primary Voltage	Existing Sheet 10B	Frozen Existing Sheet 18B	Difference	Percent
Customer Charge - Metered				
0 - 24 KW	$47.67	$47.67	$0.00	0.00%
25 - 199 KW	$47.67	$47.67	$0.00	0.00%
200 - 999 KW	$96.82	$96.82	$0.00	0.00%
1000 KW or above	$826.71	$826.71	$0.00	0.00%
Facilities Charge				
Per KW of Facilities Demand per month	$2.296	$2.296	$0.000	0.00%
Demand Charge - Summer	$3.540	$3.540	$0.000	0.00%
Demand Charge - Winter	$1.800	$2.554	$0.754	41.89%
Energy Charge - Summer				
First 180 Hours Use per month	$0.09246	$0.09246	$0.00000	0.00%
Next 180 Hours Use per month	$0.06333	$0.06333	$0.00000	0.00%
Over 360 Hours Use per month	$0.05340	$0.05340	$0.00000	0.00%
Energy Charge - Winter				
First 180 Hours Use per month	$0.07993	$0.06686	-$0.01307	-16.35%
Next 180 Hours Use per month	$0.04786	$0.04007	-$0.00779	-16.28%
Over 360 Hours Use per month	$0.04030	$0.03500	-$0.00530	-13.15%

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Large General Service

Large General Service - Rate for Service at Secondary Voltage	Existing Sheet 11A	Frozen Existing Sheet 19A	Difference	Percent
Customer Charge - Metered				
0 - 24 KW	$101.15	$101.15	$0.00	0.00%
25 - 199 KW	$101.15	$101.15	$0.00	0.00%
200 - 999 KW	$101.15	$101.15	$0.00	0.00%
1000 KW or above	$863.59	$863.59	$0.00	0.00%
Customer Charge - Separately Metered Space Heat (Frozen)	$2.32	N/A		
Facilities Charge				
Per KW of Facilities Demand per month	$2.894	$2.894	$0.000	0.00%
Demand Charge - Summer	$5.778	$5.778	$0.000	0.00%
Demand Charge - Winter	$3.109	$2.879	-$0.230	-7.40%
Energy Charge - Summer				
First 180 Hours Use per month	$0.08486	$0.08486	$0.00000	0.00%
Next 180 Hours Use per month	$0.06075	$0.06075	$0.00000	0.00%
Over 360 Hours Use per month	$0.04260	$0.04260	$0.00000	0.00%
Energy Charge - Winter				
First 180 Hours Use per month	$0.07798	$0.07141	-$0.00657	-8.43%
Next 180 Hours Use per month	$0.04670	$0.04023	-$0.00647	-13.85%
Over 360 Hours Use per month	$0.03580	$0.03140	-$0.00440	-12.29%
Separately Metered Space Heat				
Winter Season (Sheet 11A) (Frozen)	$0.05246	N/A		

Large General Service - Rate for Service at Primary Voltage	Existing Sheet 11B	Frozen Existing Sheet 19B	Difference	Percent
Customer Charge - Metered				
0 - 24 KW	$101.15	$101.15	$0.00	0.00%
25 - 199 KW	$101.15	$101.15	$0.00	0.00%
200 - 999 KW	$101.15	$101.15	$0.00	0.00%
1000 KW or above	$863.59	$863.59	$0.00	0.00%
Facilities Charge				
Per KW of Facilities Demand per month	$2.399	$2.399	$0.000	0.00%
Demand Charge - Summer	$5.647	$5.647	$0.000	0.00%
Demand Charge - Winter	$3.039	$2.811	-$0.228	-7.50%
Energy Charge - Summer				
First 180 Hours Use per month	$0.08296	$0.08296	$0.00000	0.00%
Next 180 Hours Use per month	$0.05930	$0.05930	$0.00000	0.00%
Over 360 Hours Use per month	$0.04160	$0.04160	$0.00000	0.00%
Energy Charge - Winter				
First 180 Hours Use per month	$0.07620	$0.06991	-$0.00629	-8.25%
Next 180 Hours Use per month	$0.04558	$0.03934	-$0.00624	-13.69%
Over 360 Hours Use per month	$0.03510	$0.03080	-$0.00430	-12.25%