MISSOURI PUBLIC SERVICE COMMISSION

STAFF'S

RATE DESIGN

AND

CLASS COST-OF-SERVICE

REPORT

THE EMPIRE DISTRICT ELECTRIC COMPANY

CASE NO. ER-2016-0023

Jefferson City, Missouri
April 8, 2016

** **Denotes Highly Confidential Information** **

NP

TABLE OF CONTENTS OF

STAFF REPORT

RATE DESIGN and

CLASS COST-OF-SERVICE

THE EMPIRE DISTRICT ELECTRIC COMPANY

CASE NO. ER-2016-0023

STAFF REPORT

RATE DESIGN and

CLASS COST-OF-SERVICE

THE EMPIRE DISTRICT ELECTRIC COMPANY

CASE NO. ER-2016-0023

I. Executive Summary

The Staff's direct-recommended revenue requirement increase for The Empire District Electric Company ("Empire") is $20,913,732, based on a rate of return (ROR) of 7.48% at the mid-point of the return on equity (ROE) range of 9.5% to 10.00%, as presented in Staff's *Revenue Requirement Report* also referred to as Staff's *Cost-of-Service ("COS Report").*[1] The Staff's revenue requirement, as presented in its *Accounting Schedules* filed March 25, 2016, includes expected changes for a true-up ending March 31, 2016, based on current information. The Staff will base its final amount recommendation on its true-up audit results. Staff's class cost-of-service (CCOS) study is designed to determine what rate of return is produced by each customer class on that class's currently tariffed rates, for recovery of the newly determined revenue requirement amount.[2] Staff's recommended interclass revenue responsibility shifts are designed to reasonably bring each class closer to producing the system-average rate of return used in determining Staff's recommended revenue requirement. Staff's recommended intra-class shifts will, where appropriate, redesign the rates that collect a particular class's revenues to better align that class's method of recovering revenue with the cost-causation for that class that was indicated by the class cost-of-service study. Staff's intra-class recommendations largely focus on customer charge valuation.

[1] Staff based its recommended increase in revenue requirement upon an adjusted test year including true-up estimates through March 31, 2016. The test year used in this case is based on the Electronic Management System ("EMS") run developed by Staff in File No. ER-2014-0351, dated March 26, 2015, is used as a starting point solely for calculation of Empire's revenue requirement. The *Order Setting Procedural Schedule* outlined that data shall be trued-up through March 31, 2016. Rate base items for Riverton through March 31, 2016, may be included if the in-service criteria is determined by the Commission to have been met by June 1, 2016, pursuant to Section 393.135, RSMo. The *Order Setting Procedural Schedule*, issued December 16, 2015, established the test year.

[2] Appendix 2, Schedule CCOS-1 provides a glossary of class cost of service and rate design terms. Appendix 2, Schedule CCOS-2 provides information from the *NARUC Manual* on class cost of service studies in general.

Empire has twelve (12) active service classifications.[3] The active service classifications are (1) residential service schedule RG ("RG"), (2) commercial service schedule CB ("CB"), (3) small heating service schedule SH ("SH"), (4) general power service schedule GP ("GP"), (5) special transmission service contract Praxair schedule SC-P ("SC-P"), (6) total electric building service schedule TEB ("TEB"), (7) feed mill and grain elevator service schedule PFM ("PFM"), (8) large power service schedule LP ("LP"), (9) miscellaneous service schedule MS[4] ("MS"), (10) municipal street lighting service schedule SPL[5] ("SPL"), (11) private lighting service schedule PL ("PL"), and (12) special lighting service schedule LS ("LS"). Staff combined the MS, SPL, PL and the LS rate classifications for purposes of its CCOS study because these rate schedules pertain to lighting and miscellaneous functions.

Staff recommends that the allocation of any rate increase for Empire be accomplished with a five-step process:

1. Based on Staff's CCOS results at the studied revenue requirement, Staff recommends a revenue neutral shift in revenue responsibility from the General Power ("GP") class to the Residential class. "Revenue neutral" means that the revenue shifts among classes do not change the utility's total system revenues. Specifically, Staff recommends the Residential class's revenue responsibility be increased by $3,855,000 at Staff's recommended revenue requirement, with a reduction to the GP class's revenue responsibility of $3,855,000.[6]

2. Staff allocates the portion of the revenue increase/decrease that is attributable to energy efficiency ("EE") programs from Pre-MEEIA ("Missouri Energy Efficiency Investment Act") program costs to applicable classes based on that class's level of kWh less opt-out customers.[7]

3. Staff determined the amount of revenue increase awarded to Empire not associated with the EE revenue from Pre-MEEIA revenue requirement assigned in Step 2, by subtracting the total amount in Step 2 from the total increase awarded to Empire. Staff recommends allocating this amount to various customer classes as an equal percent of

[3] Empire has Special Transmission Service Schedule ST ("ST") but Empire currently serves no customers from this service classification.

[4] The schedule is available for electric service to signal systems or similar unmetered service and for temporary or seasonal use.

[5] Includes LED street lighting pilot.

[6] Expressed as percentages, this is a 1.85% revenue neutral increase to the Residential class, and a 4.31% reduction to the GP class.

[7] The Pre-MEEIA program costs consist of the program costs for increases/decreases in the revenue requirement associated with the amortization of Pre-MEEIA program costs.

current base revenues after making the adjustment in Step 1. Based on CCOS results, Staff recommends that the PFM and combined lighting classes receive no retail increase as existing revenues received from these classes are providing more revenue to Empire than Empire's cost to serve.

4. Staff recommends the Residential customer charge be set at $15.00. This is a $2.48 increase in the customer charge and since it is above the system average increase, the applicable energy charges will have a below system average increase. With that exception, Staff generally recommends that each rate component of each class increase across-the-board for each class on an equal percentage basis after consideration of steps 1 through 4 above. Staff also recommends minor clean-up adjustments to return consistency to charges that have become slightly misaligned.

5. Staff recommends that the Commission adopt Rider Fuel and Purchased Power Adjustment Clause ("FAC") tariff sheets consistent with Staff's CCOS Report.

Current Class Revenues and Cost to Serve

Table 1shows the rate revenue responsibility shifts necessary, in dollars, for the current rate revenues from each customer class to exactly match Staff's determination of Empire's cost-of-serving that class, assuming each class provides revenues to produce an equal rate of return among classes. Also shown are the over- and under-contributions of each class as percentages, as well as the percent change to class revenue to exactly match cost of service.[8] The final column shows the current rate of return produced by each class. Staff based this CCOS study on Staff's mid-point revenue requirement recommendation, which includes an estimate of the impact to the revenue requirement of including substantial increases to the rate base value of the Riverton 12 unit.[9] Table 1 indicates that while classes do not provide equal rates of return, no class is providing a negative return, and thus no economic subsidies exist in this case. [10]

---

[8] Because other revenues, such as those produced from Empire performing ancillary services through the Southwest Power Pool's integrated market, are offset against Empire's cost of service, it is reasonable to include that allocation as an increase to each class's rate revenues for purposes of a CCOS study. In this particular case, it was necessary to reflect a small portion of Staff's true-up estimate as a negative other revenue.

[9] 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 that are required to equalize the utility's rate of return from each class. Staff presents the results of its analysis in terms of the shifts in revenue responsibilities that produce an equal rate of return for Empire from each customer class.

[10] The customer classes used in Staff's study correspond to Empire's current rate schedules, except its lighting rate schedules which Staff combined into one customer class for its study.

Table 1

	Current Revenue *plus Allocated Other Revenue*	Revenue Change to Equalize Class Rates of Return	Start % over/under contribution	% Change to Class Revenue to Exactly Match Cost of Service	Start RoR
Residential	$ 215,086,723	$23,766,240	-10.23%	11.23%	3.94%
Commercial Service	$ 44,263,685	-$41,350	0.10%	-0.09%	7.52%
Small Heating	$ 10,735,740	$758,151	-6.79%	7.18%	5.19%
Electric Building	$ 38,664,011	$1,675,059	-4.29%	4.41%	6.06%
General Power	$ 92,277,192	-$5,364,254	6.39%	-5.91%	9.81%
Large Power	$ 55,758,696	$2,437,423	-4.35%	4.46%	5.89%
Special Contract	$ 4,524,923	$262,713	-5.73%	5.94%	5.30%
Feed Mill	$ 116,634	-$24,835	27.71%	-21.52%	18.36%
Lighting	$ 7,749,189	-$2,555,437	49.68%	-33.19%	22.64%

Reviewing the column "Revenue Change to Equalize Class Rates of Return," above, a negative dollar amount indicates revenue from the customer class exceeds the cost of providing service to that class at an equalized rate of return. Therefore, to equalize revenues and cost of service, rate revenues for that class would be reduced, because the class is over-contributing to the utility's return. A positive dollar amount indicates revenue from the class is less than the cost of providing service to that class at an equal rate of return. Therefore, to equalize revenues and cost of service, rate revenues for that class would be increased, because the class is under-contributing to rate of return. In rare instances, a class will fail to provide revenues sufficient to match the non-capital-related expenses assigned and allocated to that class. In those instances, a class will provide a negative rate of return. If a class fails to provide revenues sufficient to meet variable expenses, that is properly known as a "subsidy."

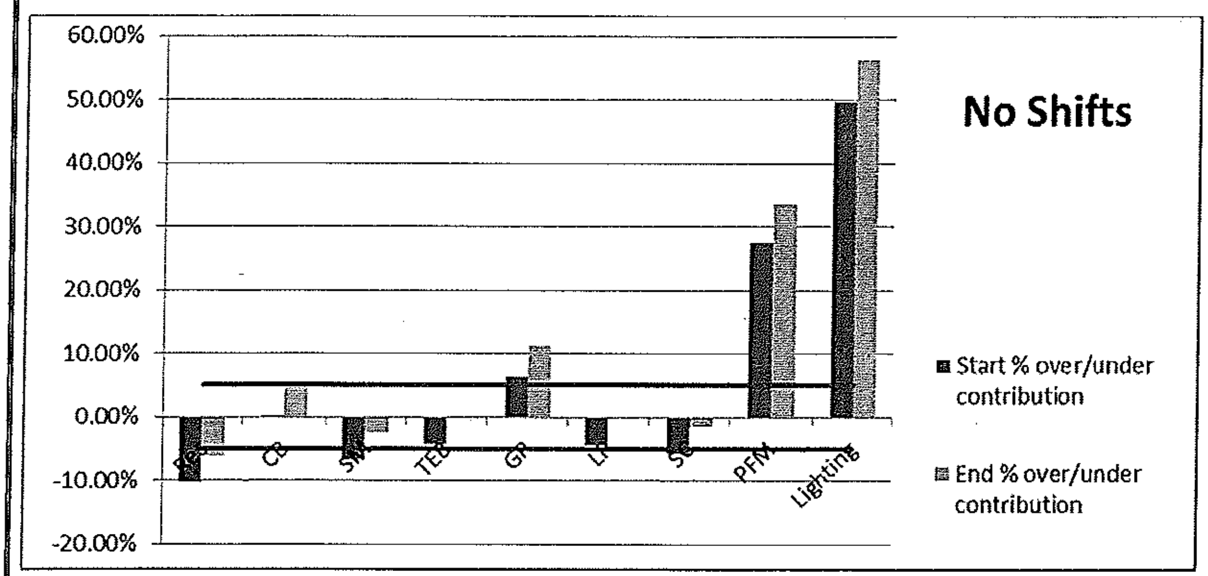
In providing its rate design recommendation, Staff recommends revenue-neutral shifts so that once the rate increase has been applied, a given class does not underpay by greater than 5% of its revenue requirement while another class or classes overpay by greater than 5% of its revenue requirement.[11] In this case, had Staff's recommended increase of approximately $21 million dollars been applied as an equal percent to all classes, the Lighting, Feed Mill, and GP classes would be overpaying by an amount outside of

[11] Staff is also mindful that in the course of general rate increase cases, no class should receive a rate reduction under ordinary circumstances.

the +5% band, while the Residential Class would have been underpaying by an amount outside of the -5% band. These results are provided in Table 2 and the accompanying chart.

Table 2

	Start % over/under contribution	System Average Increase + Energy Efficiency	End % over/under contribution
Residential	-10.23%	$ 9,612,803	-6.09%
Commercial Service	0.10%	$ 1,981,221	4.70%
Small Heating	-6.79%	$ 480,256	-2.49%
Electric Building	-4.29%	$ 1,727,769	0.14%
General Power	6.39%	$ 4,129,270	11.30%
Large Power	-4.35%	$ 2,434,486	-0.01%
Special Contract	-5.73%	$ 195,065	-1.48%
Feed Mill	27.71%	$ 5,243	33.56%
Lighting	49.68%	$ 347,619	56.44%



Because the Feed Mill and Lighting classes' current rates recover more than 20% over the revenue requirement for those classes at an equalized rate of return, Staff recommends excluding the Feed Mill and Lighting classes from any rate increase in this case.[12]

[12] Unless the ordered revenue requirement is an increase of approximately 25%, it is not necessary to adjust these classes' revenue requirements on a revenue-neutral basis.

As indicated above, without a revenue shift, the GP class would be overpaying by an amount greater than 5% of its revenue requirement at an equalized rate of return.[13] These recommended revenue neutral interclass shifts mitigate the misalignment of the revenues produced by a class with the revenue requirement of a class. However, in the course of making interclass shifts, Staff is mindful of a number of things.

> (1) In a general rate case resulting in an increase in a utility's overall revenue requirement, Staff is reluctant to recommend reducing any class's rates while the overall revenue requirement is increasing.
>
> (2) CCOS studies should serve as a guide to setting revenue requirements and are not precise. For example, CCOS studies are based on a direct-filed revenue requirement, and the allocation of that revenue requirement among specific accounts, using a specific rate of return. Unless the Commission approves that exact set of accounting schedules as well as the direst-filed billing determinants in setting the revenue requirement in a particular case, there is an inherent disconnect between the CCOS study results used in providing a party's class cost of service and rate design recommendations, and the actual class cost of service that would result at the conclusion of a case.
>
> (3) Consideration of policy, such as rate continuity, rate stability, revenue stability, minimization of rate shock to any one-customer class, meeting of incremental costs, and consideration of promotional practices are also taken into account in Staff's ultimate recommendation of Empire class revenue recovery through rate design. Staff endeavors to provide methods to implement in rates any Commission-ordered overall change in customer revenue responsibility promoting revenue stability and efficiency. Staff must also balance this, to the extent possible, retaining 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. Rate schedules should be understood by all parties, customers, and the utility as to proper application and interpretation.
>
> (4) Staff endeavors to provide the Commission with a rate design recommendation based on each customer class's relative cost-of-service responsibility and yield the total revenue requirement to all classes in a fair

[13] Another consideration is identification of which classes produce revenues that are above and below the system average rate of return. The rates of return produced by each class at current rates and the rates of return that will result from a system-average application of the revenue requirement increase are reviewed.

manner avoiding undue discrimination, including methods to recover both fixed and variable costs in a timely manner. This ensures Empire receives an amount above its marginal costs on sales of electricity, and each class is providing a contribution to cover fixed costs.

(5) In providing its rate design recommendation, Staff will recommend revenue-neutral shifts so that once the rate increase has been applied, a given class does not underpay by greater than 5% of its revenue requirement while another class or classes overpay by greater than 5% of its revenue requirement.

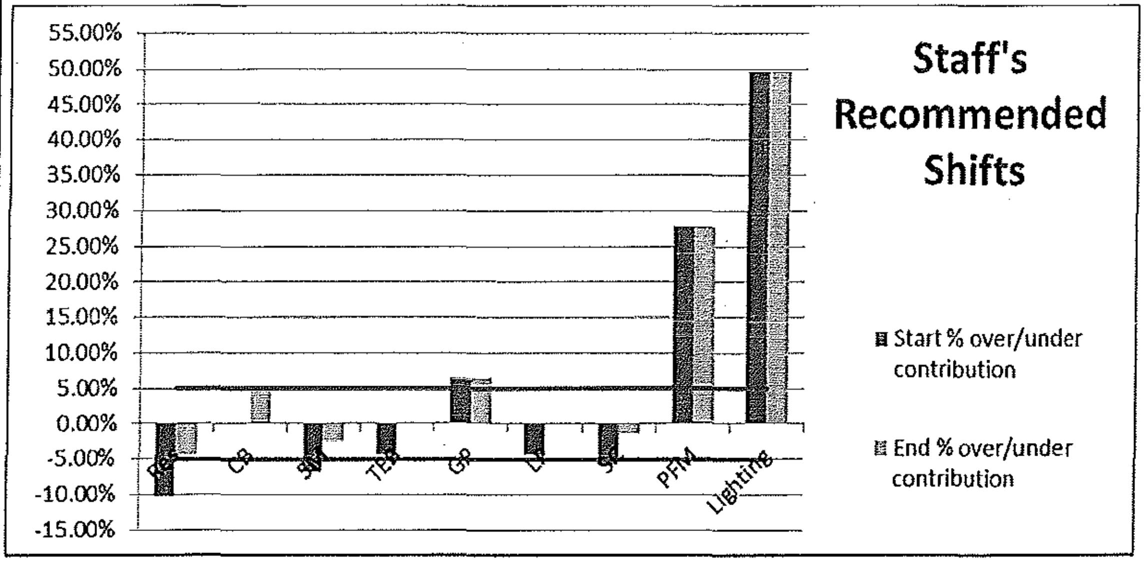
As Table 3 and its accompanying chart indicate, Staff's recommended interclass shifts in revenue responsibility will minimize the GP class's exceedance of the +5% threshold without reducing the rates paid by GP customers at a time when Empire is receiving an overall rate increase. It will also bring individual class rates of return closer to the system average.[14]

Table 3

	Revenue Responsibility Shift	Retail Increase + Energy Efficiency	End % over/under contribution	End RoR	% Increase
Residential	$3,855,000	$ 9,954,656	-4.28%	6.00%	6.62%
Commercial Service	$0	$ 2,015,241	4.78%	9.33%	4.68%
Small Heating	$0	$ 488,472	-2.41%	6.67%	4.69%
Electric Building	$0	$ 1,757,242	0.21%	7.55%	4.70%
General Power	-$3,855,000	$ 4,022,688	6.59%	9.89%	0.19%
Large Power	$0	$ 2,476,860	0.07%	7.51%	4.62%
Special Contract	$0	$ 198,487	-1.40%	6.95%	4.59%
Feed Mill	$0	$ 87	27.80%	18.39%	0.08%
Lighting	$0	$ -	49.68%	22.64%	0.00%

continued on next page

[14] At Staff's recommended revenue requirement increase, Staff made no revenue-neutral shift to reduce the revenue responsibility of the Commercial Service Class. However, if the final revenue requirement ordered by the Commission is greater than that currently recommended by Staff, it may be appropriate to make a small revenue-neutral reduction of approximately $25,000 to the CB class. This revenue would be shifted to the Residential class on a revenue-neutral basis.



Overall, these adjustments bring classes closer to cost of serving them, while still maintaining rate continuity, rate stability, and revenue stability, and while minimizing rate shock to any one-customer class.[15] Staff bases its recommendations for interclass shifts in revenue responsibility on its CCOS study results, Staff's review of Empire's revenue-neutral adjustments in previous general rate increases, and Staff's expert judgment regarding the impact of revenue shifts for all classes.

Staff's CCOS interclass revenue-responsibility recommendations are based on a scenario that assumes the Riverton 12 rate base increases considerably as part of the true-up of this case. If the Riverton 12 increase is not included in rates resulting from this case, Staff recommends not making any revenue-neutral adjustments.

Staff Expert/Witness: Sarah L. Kliethermes

II. Class Cost-of-Service Study Results

Staff performed a Detailed Base, Intermediate, and Peak ("BIP") study that is the basis for Staff's allocated revenue responsibility results. The results of Staff's CCOS study are

[15] For example, if two similar classes receive different levels of increases, customers may leave the higher-cost class in favor of the lower-cost class. Then, at the next rate case, the lower-cost class will likely have a higher allocated cost of service, while the higher-cost class will likely have a lower allocated cost of service. The resulting redesign of rates would likely cause an undoing of the initial movement of customers, with the results seesawing both rates and customers.

summarized in Table 1 above and are provided in Table 4 below. Staff developed its class allocators using the nine designated classes discussed in the Executive Summary. 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 allocates and/or assigns 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 Empire's customer classes.[16] Staff's CCOS study compares:

1. The revenues currently provided by each class at their currently tariffed rates;
2. The changes in class revenues needed to exactly match the allocated class cost of service at equalized rates of return;
3. The percentage difference between current class revenues and the class revenues needed to exactly match the allocated class cost of service at equalized rates of return;
4. The percent increase or decrease to current class revenues that would exactly match future class revenues the allocated class cost of service at equalized rates of return;
5. The rate of return currently provided by each class on the existing tariff rates, as applied to the newly-determined revenue requirement;
6. The increase in dollars that each class would receive if rates were increased across all classes by an equal percentage;
7. The rates of return that would be provided by the classes if rates were increased across all classes by an equal percentage;
8. The changes in class revenues needed to exactly match the allocated class cost of service at equalized rates of return, in addition to the system-average increase; and
9. The percentage difference between the increased class revenues and the class revenues needed to exactly match the allocated class cost of service at equalized rates of return.

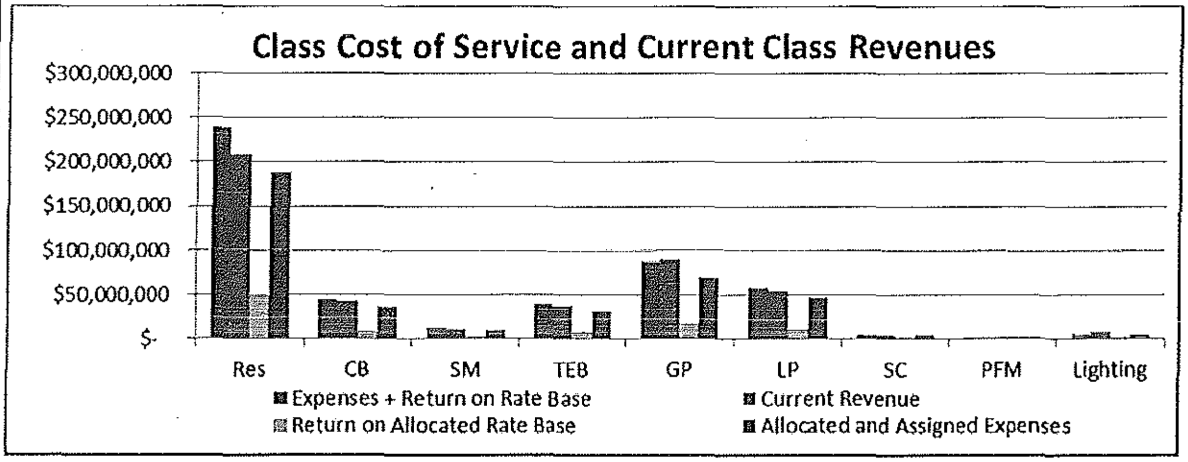
[16] Since those costs equate to Empire's revenue requirement as determined by Staff in its *Revenue Requirement Report* filed March 25, 2016, the results of Staff's CCOS study are the initial basis for Staff's recommended class revenue requirements of each Empire customer class that equitably shares Empire's total annual cost of providing electric service among them.

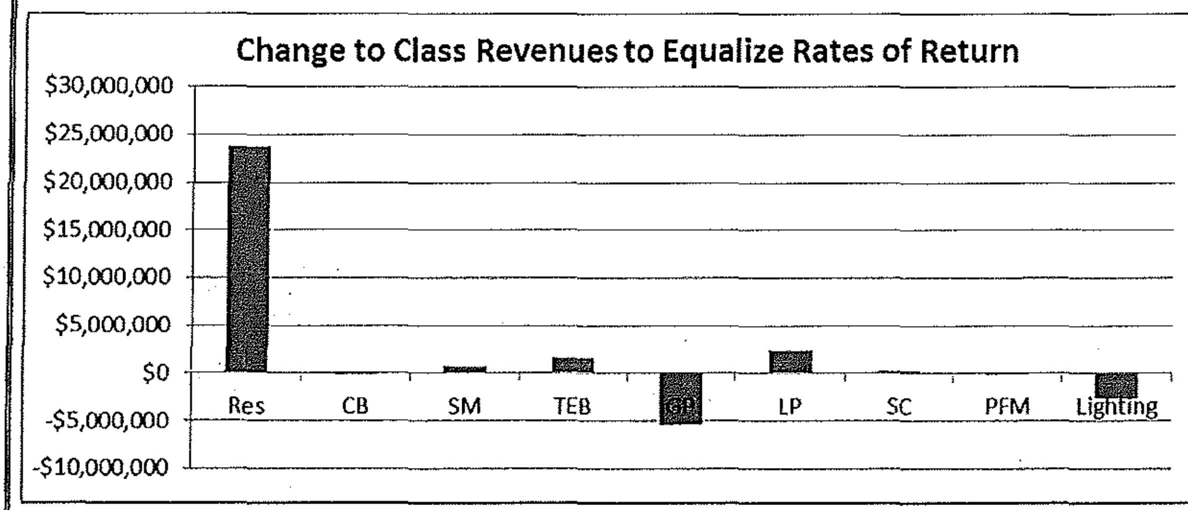
Table 4

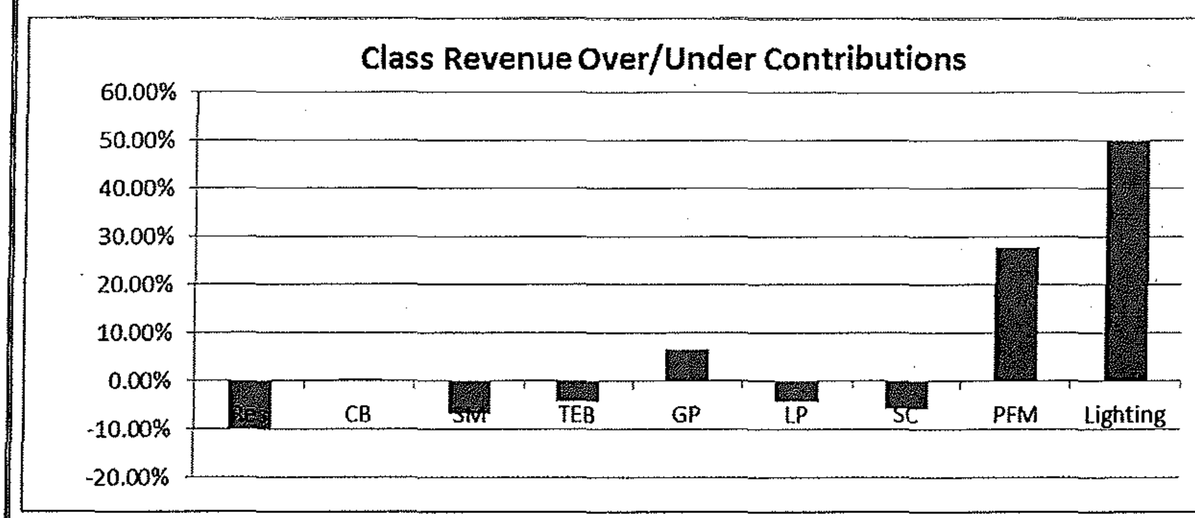
	1	2	3	4	5	6	7	8	9
	Current Revenue *plus Allocated Other Revenue*	Revenue Change to Equalize Class Rates of Return	Start % over/under contribution	% Change to Class Revenue to Exactly Match Cost	Start RoR	System Average Increase + Energy Efficiency	End RoR	Additional Revenue Change to Equalize Class Rates	End % over/under contribution
Residential	$215,086,723	$23,766,240	-10.23%	11.23%	3.94%	$ 9,612,803	5.38%	$14,153,437	-6.09%
Commercial Service	$ 44,263,685	-$41,350	0.10%	-0.09%	7.52%	$ 1,981,221	9.30%	-$2,022,571	4.70%
Small Heating	$ 10,735,740	$758,151	-6.79%	7.18%	5.19%	$ 480,256	6.64%	$277,895	-2.49%
Electric Building	$ 38,664,011	$1,675,059	-4.29%	4.41%	6.06%	$ 1,727,769	7.53%	-$52,710	0.14%
General Power	$ 92,277,192	-$5,364,254	6.39%	-5.91%	9.81%	$ 4,129,270	11.61%	-$9,493,523	11.30%
Large Power	$ 55,758,696	$2,437,423	-4.35%	4.46%	5.89%	$ 2,434,486	7.48%	$2,937	-0.01%
Special Contract	$ 4,524,923	$262,713	-5.73%	5.94%	5.30%	$ 195,065	6.92%	$67,648	-1.48%
Feed Mill	$ 116,634	-$24,835	27.71%	-21.52%	18.36%	$ 5,243	20.65%	-$30,078	33.56%
Lighting	$ 7,749,189	-$2,555,437	49.68%	-33.19%	22.64%	$ 347,619	24.70%	-$2,903,056	56.44%

The changes shown in columns 2 and 3 of Table 4 are the changes to the current rate revenues of each customer class required to exactly match that customer class's rate revenues with Empire's allocated cost to serve that class. The results are also presented, on a revenue-neutral basis, in column 8 as the revenue shifts that are required to equalize Empire's rate of return from each class after a system-average increase.

"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 from each customer class's required percentage increase. This provides the revenue-neutral adjustment to rate revenue that would be necessary to match the revenues Empire should receive from that class to Empire's cost to serve that class as shown in Table 4 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 increases is to examine the expense level of each class's cost of service independent of that class's contribution to return on rate base. This second method finds the revenue-neutral shifts needed to exactly match each class's revenue responsibility to its cost of service while providing an equalized return on rate base among those classes. The required revenue increase to match cost of service is provided below, expressed graphically in both dollars and percentages, as well as on the revenue-neutral bases.


Class Cost of Service and Current Class Revenues
$300,000,000
$250,000,000
$200,000,000
$150,000,000
$100,000,000
$50,000,000
$-
Res
CB
SM
TEB
GP
LP
SC
PFM
Lighting
Expenses + Return on Rate Base
Current Revenue
Return on Allocated Rate Base
Allocated and Assigned Expenses


Change to Class Revenues to Equalize Rates of Return
$30,000,000
$25,000,000
$20,000,000
$15,000,000
$10,000,000
$5,000,000
$0
-$5,000,000
-$10,000,000
Res
CB
SM
TEB
GP
LP
SC
PFM
Lighting


Class Revenue Over/Under Contributions
60.00%
50.00%
40.00%
30.00%
20.00%
10.00%
0.00%
-10.00%
-20.00%
CB
TEB
GP
LP
PFM
Lighting

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 that quickly dispatch 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, and/or do not consider 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.

Staff Experts/Witnesses: Sarah L. Kliethermes, Robin Kliethermes

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

A. Data Sources

Staff's CCOS study utilized Staff's revenue requirement recommendations as filed on March 25, 2016, in Staff's *Revenue Requirement Report*.[17] 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 customer-coincidental peaks, customer-non-coincidental peaks, customer-maximum peaks, and annual energy that have been weather-adjusted.

In addition, Staff obtained data from Empire, 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.

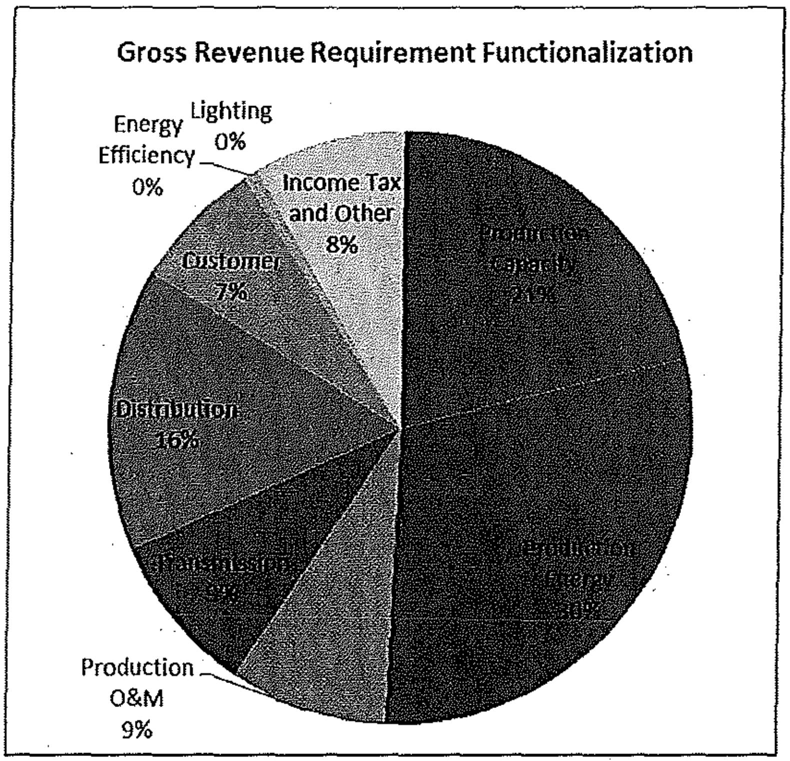
Staff Experts/Witnesses: Sarah L. Kliethermes, Robin Kliethermes

---

[17] Also referred to as Staff's *Cost of Service ("COS") Report.*

B. Functions

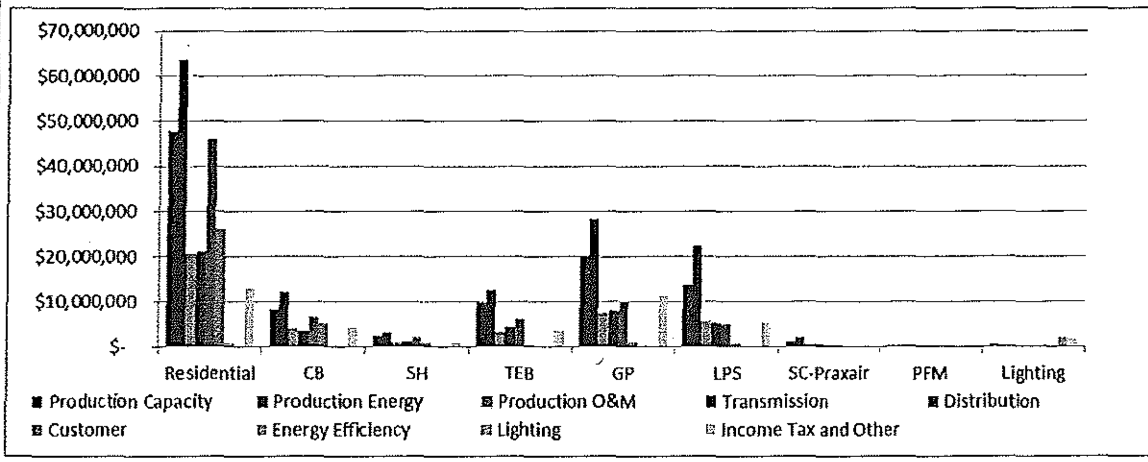
The major functional cost categories Staff used in its CCOS study are Production, Transmission, Distribution, and Customer. Within the Production function, a distinction is often made between Capacity and Energy. "Production Capacity" costs are those costs directly related to the capital cost of generation. "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 6 and 7 and the accompanying charts provided below show the functionalization in dollars by class and by the percent of each function in that class's class cost of service. For class revenue requirements, this gross functionalized revenue requirement is offset by other revenues, reducing class revenue requirements.

Table 5

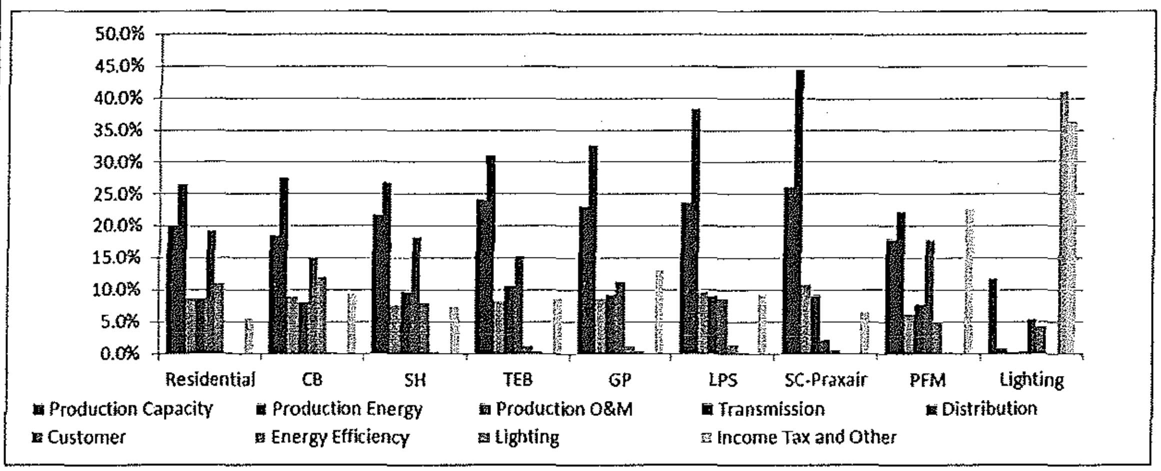
	Residential	CB	SH	TEB	GP	LPS	SC-Praxair	PFM	Lighting
Production Capacity	$ 47,748,587	$ 8,239,396	$ 2,501,849	$ 9,758,059	$ 20,169,187	$ 13,694,098	$ 1,254,436	$ 16,471	$ 608,802
Production Energy	$ 63,451,852	$ 12,191,681	$ 3,088,309	$ 12,555,865	$ 28,455,080	$ 22,338,878	$ 2,127,891	$ 20,344	$ 39,574
Production O&M	$ 20,655,964	$ 3,984,869	$ 873,524	$ 3,348,320	$ 7,535,734	$ 5,629,734	$ 517,047	$ 5,797	$ 295
Transmission	$ 20,945,067	$ 3,549,365	$ 1,125,415	$ 4,314,400	$ 8,078,094	$ 5,279,416	$ 438,539	$ 7,211	$ 21,270
Distribution	$ 45,967,175	$ 6,622,965	$ 2,102,358	$ 6,159,755	$ 9,807,723	$ 5,040,916	$ 101,934	$ 16,395	$ 276,452
Customer	$ 26,227,144	$ 5,345,954	$ 911,395	$ 505,510	$ 1,048,006	$ 803,326	$ 32,444	$ 4,507	$ 224,324
Energy Efficiency	$ 801,317	$ 151,659	$ 43,012	$ 172,463	$ 394,538	$ 112,356	$ -	$ 314	$ -
Lighting	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 2,130,815
Income Tax and Other	$ 13,055,856	$ 4,137,283	$ 848,035	$ 3,524,917	$ 11,426,952	$ 5,294,011	$ 315,317	$ 20,767	$ 1,892,220



continued on next page

Table 6

	Residential	CB	SH	TEB	GP	LPS	SC-Praxair	PFM	Lighting	Total
Production Capacity	20.0%	18.6%	21.8%	24.2%	23.2%	23.5%	26.2%	17.9%	11.7%	21.2%
Production Energy	26.6%	27.6%	26.9%	31.1%	32.7%	38.4%	44.4%	22.2%	0.8%	29.4%
Production O&M	8.6%	9.0%	7.6%	8.3%	8.7%	9.7%	10.8%	6.3%	0.0%	8.7%
Transmission	8.8%	8.0%	9.8%	10.7%	9.3%	9.1%	9.2%	7.9%	0.4%	8.9%
Distribution	19.2%	15.0%	18.3%	15.3%	11.3%	8.7%	2.1%	17.9%	5.3%	15.5%
Customer	11.0%	12.1%	7.9%	1.3%	1.2%	1.4%	0.7%	4.9%	4.3%	7.2%
Energy Efficiency	0.3%	0.3%	0.4%	0.4%	0.5%	0.2%	0.0%	0.3%	0.0%	0.3%
Lighting	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	41.0%	0.4%
Income Tax and Other	5.5%	9.4%	7.4%	8.7%	13.1%	9.1%	6.6%	22.6%	36.4%	8.3%



As indicated most clearly in the graph version of Table 6, the portion of a class's revenue requirement related to that class's consumption of energy varies greatly across classes.

Staff Experts/Witnesses: Sarah L. Kliethermes, Robin Kliethermes

C. Allocation of Production Costs

For CCOS purposes, Staff assumes that Empire uses the Missouri-allocated portion of all of Empire's generation facilities primarily to produce electricity for Empire's retail customers. A production-capacity (demand) or a production-energy (energy) allocator appropriately allocates Empire's costs for plant investment and the production expenses provided on its income statement. Empire's generation facilities are predominantly considered fixed assets for purposes of setting rates, and so the costs of these assets are considered demand-related and apportioned to the rate classes based on 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 based on the production-energy allocator. The demand and energy characteristics of Empire'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 Empire's generation fleet characteristics and its load characteristics. In practice, because Empire 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 Electric Utility Cost Allocation Manual* ("*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 have a lower average cost of energy, while Peak plants tend to be less expensive to install, but have 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 Empire'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.

Empire's generation fleet characteristics

As part of this case, Empire requests recognition in rate base of the conversion of its Riverton 12 Combustion Turbine (CT) unit into a Combined Cycle (CC) unit with a Heat Recovery Steam Generator (HRSG). Staff based its CCOS study and rate design recommendation on a scenario that assumes the operation of the HRSG. Staff has also calculated production allocators for a scenario which assumes continued operation of Riverton 12 as a CT.

Empire's "Base" generating plants are the Ozark Beach hydroelectric facility, the Iatan 2 supercritical coal plant, the Iatan 1 coal plant, the Plum Point coal plant, and the Asbury coal plant.[18,19,20] Each of these coal plants has emissions control equipment that increases their capacity costs and the operating costs, while also slightly decreasing the net amount of electrical energy produced by burning the same amount of coal. Staff determined that the average capacity cost, net of depreciation reserve, for Empire's Base generation is approximately $1,253,471 /MW. However, Staff found that the average fuel cost for these plants was only $17.99 /MWh. Taken together, Empire's Base generation ran at an 83.08% capacity factor in Staff's fuel model.

Empire's "Intermediate" generating plants are the State Line combined cycle unit, and the Riverton 12 gas-fired CC, which is expected at this time to recognize as in service as a part of this case.[21] Staff determined that the average capacity cost, net of depreciation reserve, for Empire's Intermediate generation is approximately $686,182 /MW, and the

[18] 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. As a price taker, these plants typically do not set the marginal price of energy.

[19] Empire's interest in Plum Point consists of a 50MW joint ownership, as well as a 50MW Purchase Power Agreement ("PPA"). As in prior cases, in this case, Staff modeled the PPA as part of Empire's capacity in its fuel run. For capacity valuations, Staff treated the PPA as additional ownership interest, so that weightings would be consistent among production-capacity allocators.

[20] Empire also has a wind PPA. Staff did allocate the expense of the PPA to the classes using the BIP allocators; however, Staff did not include the PPA in allocator development.

[21] 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.

average fuel cost for these plants was $23.04 /MWh. Taken together, Empire's Intermediate generation ran at a 43.49% capacity factor in Staff's fuel model.

Empire's "Peaking" generating plants that ran in Staff's fuel model are Energy Center Units 3 and 4, and Riverton Units 8 and 9.[22, 23] These units are all simple cycle gas turbines. Staff determined that the average capacity cost, net of depreciation reserve, for Empire's Peaking generation is only approximately $202,066 /MW. Staff found that the average fuel cost for these plants was $34.55 /MWh. Taken together, Empire's Peaking generation that did run in Staff's fuel model ran at a 1.74% capacity factor.

Empire's load characteristics

Empire has a larger electric space-heating load relative to its total load in comparison to other electric utilities. Space heating generally helps to increase load at night when plants would otherwise run at minimum capacities, and when wind energy tends to be more plentiful. Due in part to the impact of its residential space-heating load, Empire's overall load is relatively diverse. For example, Empire's residential class's highest peak and Empire's all-electric class's highest peak occurred in January 2015, and various other Empire classes experienced peaks during the shoulder month of October and the summer months of August, June and July. Taken together, this diversity allows Empire to require less generation capacity than if all of its customers used energy at the same times.

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 at the hour when the overall system peak occurs. Coincident-peak demand reflects the maximum amount of diversity because most customer classes are not at their individual class peaks at the time of the coincident peak.

[22] Empire's fleet includes two additional simple cycle units at Energy Center, and an additional simple cycle at Riverton. The State Line combined cycle facility consists of two gas turbines, and a Heat Recovery Steam Generator ("HRSG") that can be powered with waste heat from either or both turbines.

[23] Gas 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 turbines are capable of high capacity factors, but tend to have the lowest capacity factors of any units, as operated. However, because Empire participates in the SPP integrated energy market; its generation is dispatched as part of the larger SPP fleet, so its 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.

Class peak demand, which is the maximum hourly demand of the class as a whole, often does not occur at the same hour, i.e., does not coincide with, the system peak. Although not all customers within a class 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's load at the time of system peak.

Finding Class Demands

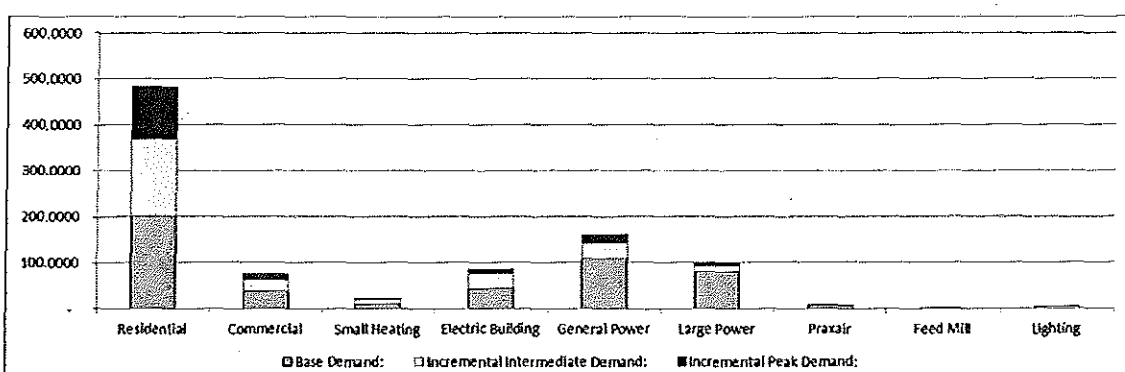
1. Staff found each class's average demand in MW. That MW of demand value is the "base demand" used for each class in the BIP calculation.

2. Staff found each class's demand in MW at the time of each month's system peak. Staff then averaged each class's 12 demands to a single MW value. That additional MW value over the base demand MW value is each class's intermediate demand. The difference between each class's base demand and its intermediate demand is its incremental intermediate demand.

3. Staff found each class's demand in MW at the time of the four system peaks. Staff then averaged each class's demands at those four peaks to a single MW value. That MW value is each class's peak demand. The difference between each class's 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	Commercial	Small Heating	Electric Building	General Power	Large Power	Praxair	Feed Mill	Lighting
Base Demand:	200.94	38.20	10.94	45.00	110.04	81.04	8.11	0.08	3.93
Incremental Intermediate Demand:	169.46	24.57	8.97	31.30	32.81	12.32	-	0.05	-
Incremental Peak Demand:	112.48	12.75	2.99	9.16	18.29	5.78	-	0.01	-



Finding Class Energy Usage

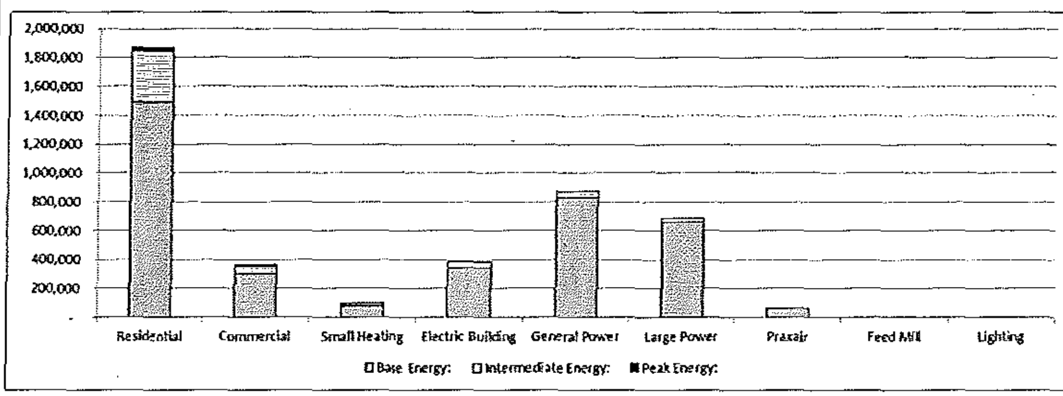
1. Staff analyzed each class's weather-normalized energy usage for each hour of the year. In a given hour, if a class had energy usage (MWh) equal to or below its base demand (MW), then Staff recorded that energy usage as base usage. If, in that hour, a class had energy usage in excess of its base demand,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

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	Commercial	Small Heating	Electric Building	General Power	Large Power	Praxair	Feed Mill	Lighting
Base Energy:	1,493,042	301,606	79,872	342,111	830,082	657,946	66,473	451	38
Intermediate Energy:	347,966	54,159	12,498	38,995	39,955	32,149	-	144	-
Peak Energy:	29,304	6,499	445	554	3,706	-	-	-	-



Calculating BIP Allocators

The BIP method is described in the *NARUC Manual*, in Part IV, C, Section 2.[24] Staff developed production-capacity and production-energy allocators by matching the

[24] Appendix 2, Schedule CCOS-2 details the BIP method as described in the *NARUC Manual*, as published, January 1992.

average capacity cost of each type of capacity cost with the BIP demands of each customer class, and by matching the average energy cost of each type of energy cost 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's base level of demand, (2) the relatively moderate capacity costs of intermediate generation on each class's intermediate level of demand, and (3) the relatively inexpensive capacity costs of peaking generation on each class's peak level of demand. Under this approach, Empire's net investment in each of the plants assigned to each of the BIP components is allocated to the classes based on each class's 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.[25]

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's base energy usage, (2) the relatively moderate fuel costs of intermediate generation on each class's intermediate energy usage, and (3) the relatively expensive fuel costs of peaking generation on each class's 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's base, intermediate, and peak 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.[26]

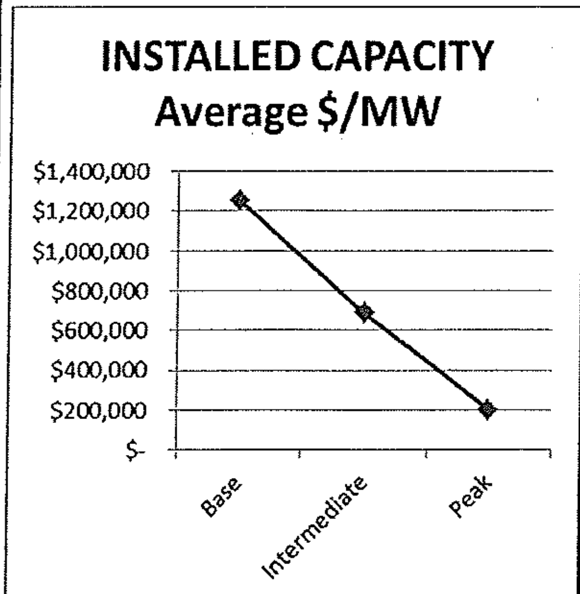
Staff also used the assignments of generating plant to BIP components to develop allocators for Empire's production-related operating and maintenance expense, and fuel stored on site. This method expressly assigns the expenses of each plant to follow that plant. Each of the generating plants causes production plant operating and maintenance expenses. 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's assigned plant responsibility. Similarly, fuel stored at each plant is associated with particular

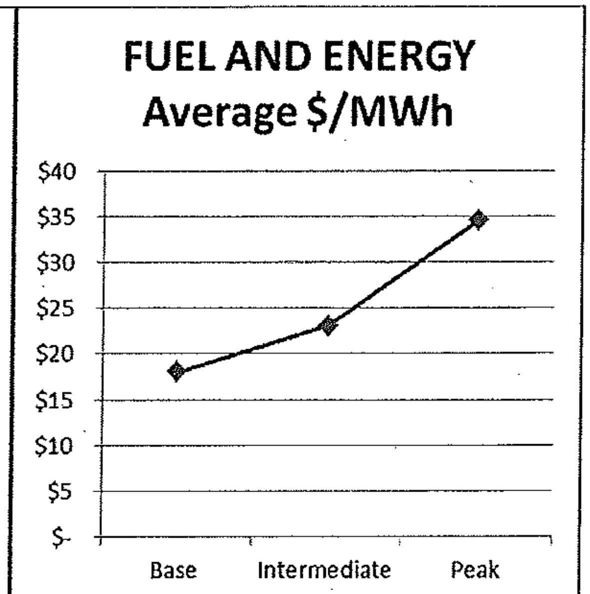
[25] A separate capacity-related allocator is used to allocate the return on investment associated with fuel stored at the various generation stations.

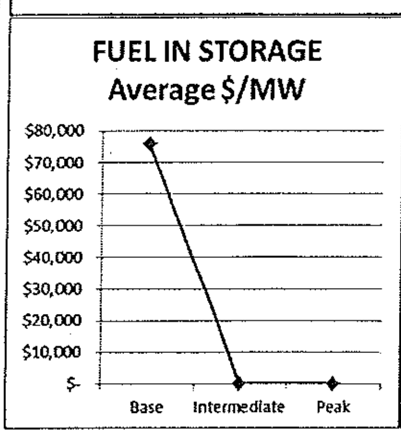
[26] A separate energy-related allocator is used to allocate the operations and maintenance expense associated with each of the various generation stations.

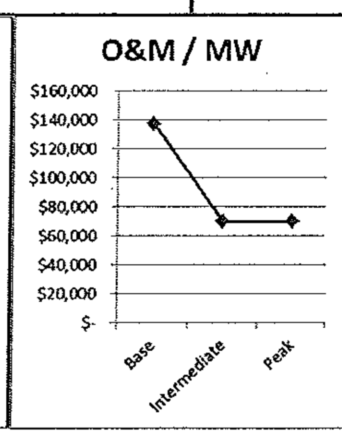
plants, so Staff developed factors to allocate the fuel associated with particular plants with the plant allocated to each customer class.

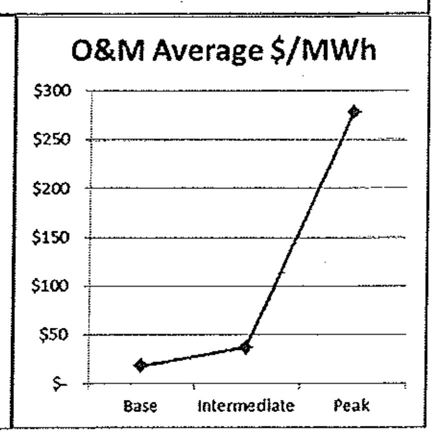
Staff's detailed BIP study reasonably balances the offsetting impacts of the relative costs of energy, capacity, O&M, and fuel-in-storage associated with meeting the demand and usage characteristics of Empire's load. Thus, Staff's BIP method is a reasonable method for allocating the production-related 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 graphs provided below indicate the relative values of each of these items.





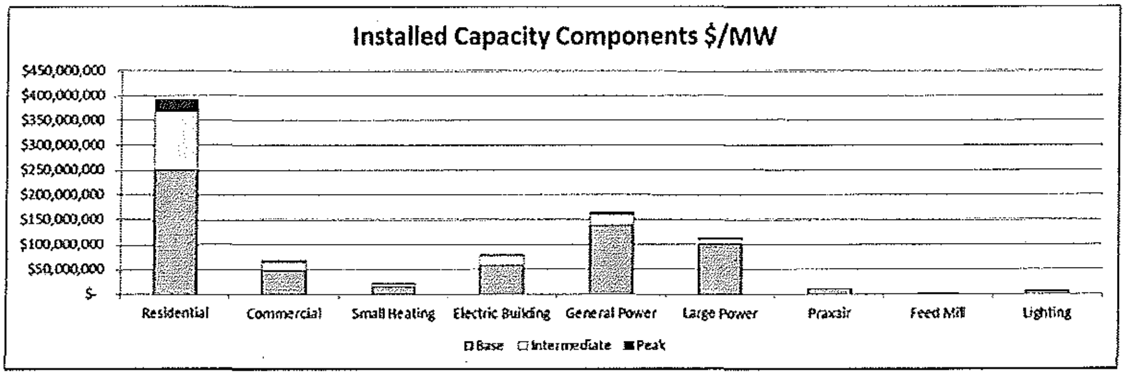




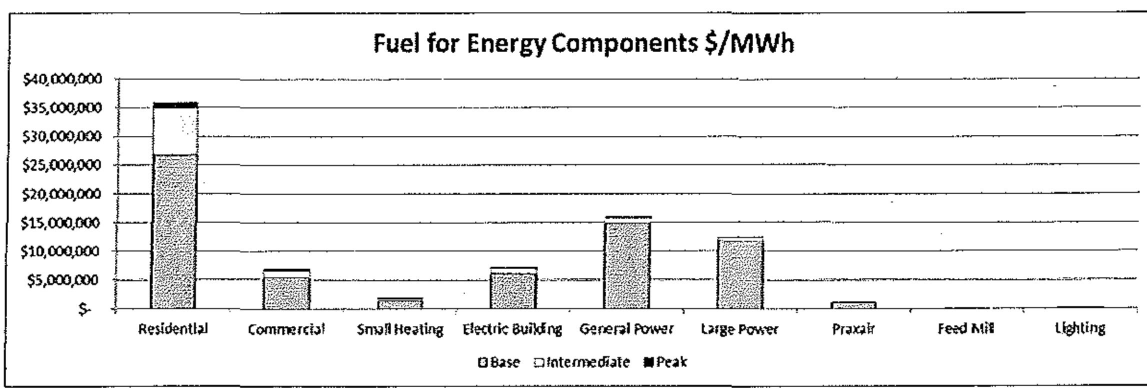


The allocators that result from applying these values to Empire's BIP load characteristics are provided in the graphs and tables below.

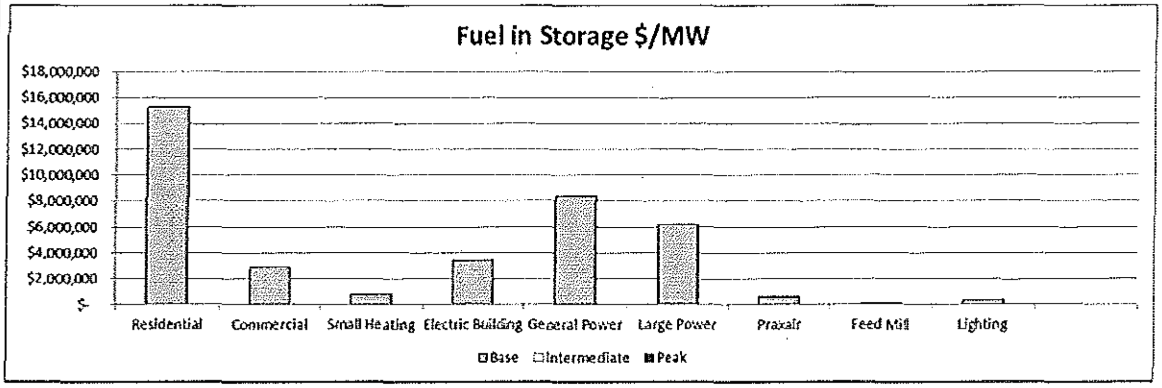
BIP Installed Capacity Allocator										
	Total	Residential	Commercial	Small Heating	Electric Building	General Power	Large Power	Praxair	Feed Mill	Lighting
Base Capacity	$ 624,559,240	$ 251,866,101	$ 47,877,560	$ 13,706,700	$ 56,402,413	$ 137,931,897	$ 101,583,759	$ 10,160,632	$ 99,024	$ 4,931,153
Incremental Intermediate Capacity	$ 191,767,840	$ 116,277,578	$ 16,859,480	$ 6,152,990	$ 21,476,796	$ 22,514,989	$ 8,452,384	$ -	$ 33,623	$ -
Incremental Peak Capacity	$ 32,624,908	$ 22,728,340	$ 2,576,134	$ 604,984	$ 1,850,113	$ 3,695,578	$ 1,167,939	$ -	$ 1,819	$ -
Totals:	$ 848,951,987	$390,872,019	$67,313,175	$20,464,674	$79,729,322	$164,142,464	$111,204,082	$10,160,632	$134,466	$4,931,153
BIP Installed Capacity Allocator:		46.04%	7.93%	2.41%	9.39%	19.33%	13.10%	1.20%	0.02%	0.58%



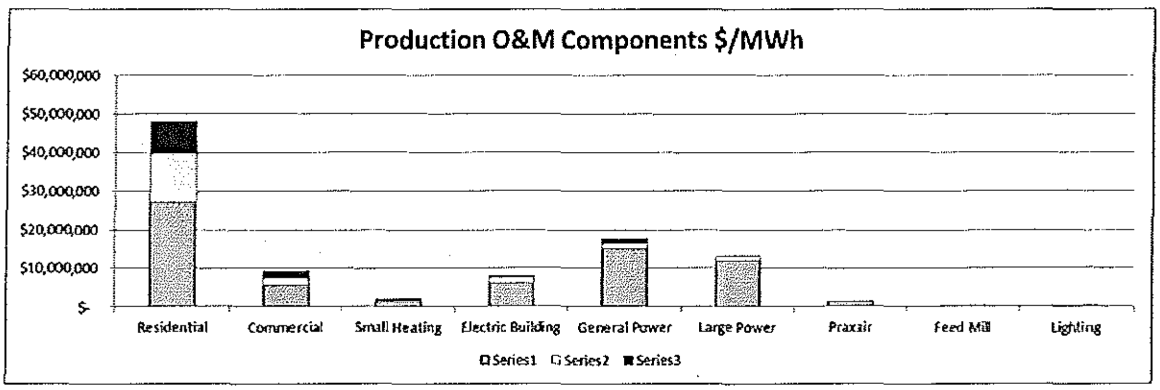
BIP Fuel for Energy Allocator (annual)										
	Total	Residential	Commercial	Small Heating	Electric Building	General Power	Large Power	Praxair	Feed Mill	Lighting
Base Energy Usage	$ 67,845,049	$ 26,857,282	$ 5,425,384	$ 1,436,768	$ 6,153,997	$ 14,931,759	$ 11,835,323	$ 1,195,740	$ 8,115	$ 682
Incremental Intermediate Usage	$ 12,118,234	$ 8,018,654	$ 1,248,050	$ 288,013	$ 898,622	$ 920,739	$ 740,846	$ -	$ 3,310	$ -
Incremental Peak Usage	$ 1,399,786	$ 1,012,613	$ 224,563	$ 15,387	$ 19,147	$ 128,076	$ -	$ -	$ -	$ -
Totals:	$ 81,363,068	$35,888,548	$6,897,997	$1,740,167	$7,071,765	$15,980,575	$12,576,169	$1,195,740	$11,425	$682
BIP Fuel for Energy Allocator:		44.11%	8.48%	2.14%	8.69%	19.64%	15.46%	1.47%	0.01%	0.00%



BIP Fuel in Storage Allocator										
	Total	Residential	Commercial	Small Heating	Electric Building	General Power	Large Power	Praxair	Feed Mill	Lighting
Base Capacity	$ 37,822,354	$ 15,252,627	$ 2,899,392	$ 830,057	$ 3,415,644	$ 8,352,945	$ 6,151,757	$ 615,312	$ 5,997	$ 298,623
Incremental Intermediate Capacity	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Incremental Peak Capacity	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Totals:	$ 37,822,354	$15,252,627	$2,899,392	$830,057	$3,415,644	$8,352,945	$6,151,757	$615,312	$5,997	$298,623
BIP Fuel in Storage Allocator (Capacity):		40.33%	7.67%	2.19%	9.03%	22.08%	16.26%	1.63%	0.02%	0.79%



BIP O&M Allocator										
	Total	Residential	Commercial	Small Heating	Electric Building	General Power	Large Power	Praxair	Feed Mill	Lighting
Base Usage	$ 68,351,647	$ 27,057,825	$ 5,465,895	$ 1,447,496	$ 6,199,949	$ 15,043,255	$ 11,923,697	$ 1,204,668	$ 8,176	$ 687
Incremental Intermediate Usage	$ 19,514,562	$ 12,912,816	$ 2,009,794	$ 463,801	$ 1,447,093	$ 1,482,709	$ 1,193,019	$ -	$ 5,330	$ -
Incremental Peak Usage	$ 11,274,024	$ 8,155,689	$ 1,808,657	$ 123,927	$ 154,210	$ 1,031,541	$ -	$ -	$ -	$ -
Totals:	$ 99,140,233	$48,126,330	$9,284,346	$2,035,223	$7,801,251	$17,557,505	$13,116,716	$1,204,668	$13,506	$687
BIP O&M Allocator (Energy):		48.54%	9.36%	2.05%	7.87%	17.71%	13.23%	1.22%	0.01%	0.00%



Staff Experts/Witnesses: Sarah L. Kliethermes, 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. Empire's transmission investment and transmission costs comprise approximately 9% of the functionalized investment and costs that Staff allocated to Empire's customer classes. Empire'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's 12 coincident peak (CP).[27] Staff recommends the 12 CP allocation method for this purpose because, by including periods of normal use and intermittent peak use throughout all twelve months of the year, it takes into account the need for a transmission system designed both to transmit electricity during peak loads and to transmit electricity throughout the year.

Staff Experts/Witnesses: Sarah L. Kliethermes, Robin Kliethermes

E. Allocation of Distribution and Customer Service Costs

Distribution is the final link in the chain built to deliver electricity to customers' homes or businesses. 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 that can be delivered into homes for lights and appliances. 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 coincident peak (as measured at substation voltage) to allocate substation costs.

In Case No. ER-2014-0351, Empire conducted a minimum distribution study to split the cost of poles, towers, fixtures; and overhead ("OH") and underground ("UG") distribution lines, conductors, and conduit between primary, secondary and customer related. Staff relied on information from this study in allocating distribution plant investment to the classes.[28] However, Staff allocated the costs of the primary distribution facilities on the basis of each

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

[28] Staff does not draw the same conclusion as Dr. Overcast in that case in assuming all costs allocated to the classes on customer count are necessarily "customer-related" for purposes of determining the cost to be recovered through the customer charge.

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

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

Table 7
Allocation of Demand Related Distribution Facilities

Functional Category	**Amount of Diversity Among Customers**	**Allocation Method To Capture Diversity**
Transmission	High	12 Coincident Peak
Substations	Moderate to High	Coincident Peak at Substation
Primary	Moderate to High	Coincident Peak at Primary Voltage
Secondary	Low to Moderate	Coincident Peak at Secondary Voltage
Line Transformers	Low to Moderate	Coincident Peak at Secondary Voltage

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

Staff recommends allocating service lines and meter costs using the same allocator that Empire used to allocate these costs. These allocators are based on an Empire study that weights the number of installations taking service by class and by the cost of the meter and service used to serve that class. In addition, Staff recommends using the same allocators that Empire used for allocating meter reading costs, uncollectible accounts, customer services expense, and for allocating customer deposits. These allocators are derived using Empire studies that directly assign the costs of meter reading, uncollectible accounts, customer service expense, and customer deposits to each customer class.[29] The allocators are the fraction of total costs in these accounts assigned to each class, respectively.

Staff Expert/Witness: Robin Kliethermes

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"). Staff also uses rate revenues in developing its 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 Empire 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.

Staff allocated other electric revenues to the rate classes depending on the source of those revenues. Unlike other Missouri electric utilities, at this time, Empire is a net purchaser of energy in the SPP IM. Because Empire was a net purchaser of off-system energy in Staff's direct fuel run, it was not necessary to separately allocate the cost of fuel and purchased power to make off-system sales to the classes. Staff allocated all off-system revenues from the sale of energy through the IM on dollar-weighted energy, and other off-system revenues including transmission system ancillary services, were allocated on dollar-weighted capacity. Because the CCOS software imports these values as separate line items, 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.

Staff Experts/Witnesses: Sarah L. Kliethermes, Robin Kliethermes

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

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 Empire's investment in plant, so these taxes are allocated to customer classes based on the sum of the previously allocated net production, transmission, distribution and general plant investment.

Payroll taxes are directly related to Empire's payroll, so these taxes are allocated to customer classes based on 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 allocated Empire's income taxes based on class earnings.

Staff Expert/Witness: Robin Kliethermes

H. Allocation of Seasonal Energy Costs

Empire's rates are seasonal as 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's 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 incurred during the summer billing months, as well as for total company. On average, summer season wholesale energy costs are 115% of non-summer season wholesale energy costs. Table 8 provides the seasonal costs per class below.

Table 8

	Residential	Commercial	Small Heating	Electric Building	General Power	Large Power	Praxair	Feed Mill	Lighting
Summer $/MWh at Market Prices used in Fuel Run (at Generation):	$ 30.21	$ 29.97	$ 30.17	$ 29.62	$ 29.25	$ 28.77	$ 28.28	$ 29.64	$ 25.88
Non-Summer $/MWh at Market Prices used in Fuel Run (at Generation):	$ 25.94	$ 26.04	$ 26.03	$ 25.96	$ 25.84	$ 25.67	$ 25.50	$ 26.19	$ 24.66
Summer % of total kWh:	34%	36%	32%	34%	37%	37%	33%	45%	31%
Summer % of total $ (Fuel Run):	37%	40%	35%	37%	40%	39%	36%	48%	32%
Summer to NonSummer Index (Fuel Run):	116%	115%	116%	114%	113%	112%	111%	113%	105%

Empire continues to move towards a dual-peak with its winter peak growing relative to its summer peak. Staff recommends that as part of its next rate case, Empire evaluate the reasonableness and practicality of moving towards Seasonal and Shoulder rates, as opposed to Summer and Non-Summer rates. Such a rate structure would consist of two sets of rates, but would apply to (1) the summer and winter months, and (2) the fall and spring months.

Staff Experts/Witnesses: Sarah L. Kliethermes, Robin Kliethermes

I. Allocation of Energy Efficiency Costs

Empire does not currently offer energy efficiency programs pursuant to the Missouri Energy Efficiency Investment Act. Accordingly, Staff allocates all Empire energy efficiency costs to each customer class based on each class's energy usage minus the energy usage of customers who opt-out of participation in those programs. These historical costs are included in rate base and amortized.

Staff Experts/Witnesses: Sarah L. Kliethermes, Robin Kliethermes

J. Energy Costs

The total cost of energy procured through the SPP Day Ahead Market for each class and the average cost of energy based on each class's load shape are provided in the table below. Ancillary service, real time market, transmission, and capacity costs are not included in these amounts.

	Residential	Commercial	Small Heating	Electric Building	General Power	Large Power	Praxair	Feed Mill	Lighting
Cost of Energy at Market Prices used in Fuel Run:	$ 51,216,185	$ 9,952,006	$ 2,538,049	$ 10,384,969	$ 23,691,227	$ 18,503,105	$ 1,756,666	$ 16,508	$ 949,134
Cost of Energy at Actual Market Prices through Update:	$ 54,875,064	$ 10,471,872	$ 2,703,147	$ 11,006,135	$ 24,566,142	$ 19,069,256	$ 1,807,894	$ 17,141	$ 949,348
MWh @ Generation:	1,870,313	362,264	92,816	381,661	873,744	690,095	66,473	595	37,909
$/MWh at Market Prices used in Fuel Run (at Generation):	$ 27.38	$ 27.47	$ 27.34	$ 27.21	$ 27.11	$ 26.81	$ 26.43	$ 27.76	$ 25.04
$/MWh at Actual Market Prices through Update (at Generation):	29.34	28.91	29.12	28.84	28.12	27.63	27.20	28.82	25.04
MWh @ Meter:	1,650,354	313,719	89,812	369,575	903,803	665,630	66,578	646	32,274
$/MWh at Market Prices used in Fuel Run (at Meter):	$ 31.03	$ 31.72	$ 28.26	$ 28.10	$ 26.21	$ 27.80	$ 26.39	$ 25.56	$ 29.41
$/MWh at Actual Market Prices through Update (at Meter):	$ 33.25	$ 33.38	$ 30.10	$ 29.78	$ 27.18	$ 28.65	$ 27.15	$ 26.54	$ 29.42
Class % of Total Cost of Energy at Market Prices used in Fuel Run:	43.036%	8.362%	2.133%	8.726%	19.907%	15.548%	1.476%	0.014%	0.798%
Class % of Total Cost of Energy at Actual Market Prices through Update:	43.737%	8.346%	2.154%	8.772%	19.580%	15.199%	1.441%	0.014%	0.757%

Staff Experts/Witnesses: Sarah L. Kliethermes, Robin Kliethermes

IV. Rate Design

In providing its rate design recommendation, Staff will recommend revenue-neutral shifts so that once the rate increase has been applied, a given class does not underpay by greater than 5% of its revenue requirement while another class or classes overpay by greater than 5% of its revenue requirement.[30] In this case, had Staff's recommended increase of approximately $21 million dollars been applied as an equal percent to all classes, the Lighting, Feed Mill, and GP classes would be overpaying by an amount outside of the +5% band, while the Residential Class would have been underpaying by an amount outside of the -5% band.

Staff's recommended revenue-neutral interclass shifts mitigate the misalignment of the revenues produced by a class with the revenue requirement of a class. However, in the course of making interclass shifts, Staff is mindful of a number of things.

> 1. In a general rate case resulting in an increase in a utility's overall revenue requirement, Staff is reluctant to recommend reducing any class's rates while the overall revenue requirement is increasing.
>
> 2. CCOS studies should serve as a guide to setting revenue requirements and are not precise. For example, CCOS studies are based on a direct-filed revenue requirement, and the allocation of that revenue requirement among specific accounts, using a specific rate of return. Unless the Commission approves that exact set of accounting schedules as well as the direst-filed billing determinants in setting the revenue requirement in a particular case, there is an inherent disconnect between the CCOS study results used in providing a party's class cost of service and rate design recommendations, and the actual class cost of service that would result at the conclusion of a case.
>
> 3. Consideration of policy, such as rate continuity, rate stability, revenue stability, minimization of rate shock to any one-customer class, meeting of incremental costs, and consideration of promotional practices are also taken into account in Staff's ultimate recommendation of Empire class revenue recovery through rate design. Staff endeavors to provide methods to implement in rates any Commission-ordered overall change in customer revenue responsibility promoting revenue stability and efficiency. Staff must also balance this, to the extent possible, retaining existing rate schedules, rate structures, and important features of the current rate design that reduce the

---

[30] Staff is also mindful that in the course of general rate increase cases, no class should receive a rate reduction under ordinary circumstances.

number of customers that switch rates looking for the lowest bill, and mitigate the potential for rate shock. Rate schedules should be understood by all parties, customers, and the utility as to proper application and interpretation.

4. Staff endeavors to provide the Commission with a rate design recommendation based on each customer class's relative cost-of-service responsibility and yield the total revenue requirement to all classes in a fair manner avoiding undue discrimination, including methods to recover both fixed and variable costs in a timely manner. This ensures Empire receives an amount above its marginal costs on sales of electricity, and each class is providing a contribution to cover fixed costs.

5. In providing its rate design recommendation, Staff will recommend revenue-neutral shifts so that once the rate increase has been applied, a given class does not underpay by greater than 5% of its revenue requirement while another class or classes overpay by greater than 5% of its revenue requirement.

Staff recommends that the allocation of any rate increase for Empire be accomplished with a five-step process:

1. Based on Staff's CCOS results at the studied revenue requirement, Staff recommends a revenue-neutral shift in revenue responsibility from the General Power ("GP") class to the Residential class. "Revenue neutral" means that the revenue shifts among classes do not change the utility's total system revenues. Specifically, Staff recommends the Residential class's revenue responsibility be increased by $3,855,000 at Staff's recommended revenue requirement, with a reduction to the GP class's revenue responsibility of $3,855,000.[31]

2. Staff allocates the portion of the revenue increase/decrease that is attributable to energy efficiency ("EE") programs from Pre-MEEIA ("Missouri Energy Efficiency Investment Act") program costs to applicable classes based on that class's level of kWh less opt-out customers.[32]

3. Staff determined the amount of revenue increase awarded to Empire not associated with the EE revenue from Pre-MEEIA revenue requirement assigned in Step 2, by subtracting the total amount in Step 2 from the total increase awarded to Empire. Staff recommends allocating this amount to various customer classes as an equal percent of current base revenues after making the adjustment in Step 1.

[31] Expressed as percentages, this is a 1.85% revenue neutral increase to the Residential class, and a 4.31% reduction to the GP class.

[32] The Pre-MEEIA program costs consist of the program costs for increases/decreases in the revenue requirement associated with the amortization of Pre-MEEIA program costs.

Based on Study results, Staff recommends that the PFM and combined lighting classes receive no retail increase as existing revenues received from these classes are providing more revenue to Empire than Empire's cost to serve.

4. Staff recommends the Residential customer charge be set at $15.00. This is a $2.48 increase in the customer charge and since it is above the system average increase, the applicable energy charges will have a below system average increase. With that exception, Staff generally recommends that each rate component of each class increase across-the-board for each class on an equal percentage basis after consideration of steps 1 through 4 above. Staff also recommends minor clean-up adjustments to return consistency to charges that have become slightly misaligned.

5. Staff recommends that the Commission adopt Rider Fuel and Purchased Power Adjustment Clause ("FAC") tariff sheets consistent with Staff CCOS Report.

Rate Structure

Once Staff determines the revenue requirement, Staff must calculate the rates that will be charged to the utility's customers.[33] The use of different charge elements on various rate schedules is discussed in terms of "rate structure." 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 send price signals to the customer(s). The most simple rate structures consist of from two to five elements, while structures that are more complex may have more than 16 elements.

Empire's Residential, Commercial, and Space Heating rate schedules consist of the following:

(1) A customer charge, payable as a fixed dollar amount each month regardless of usage. This charge does not vary by season.

(2) A summer energy charge, which is billed at the same $/kWh amount for every kWh consumed from June 16 – September 16.

(3) A first block non-summer energy charge, which is billed at the same $/kWh amount as the summer energy charge, but only for a certain number of kWh

[33] Some revenues are recovered through miscellaneous charges such as line extension policies or bad check fees.

each month. For Residential customers, the first block non-summer energy charge applies to the first 600 kWh each month; for Commercial and Space Heating customers, the first block non-summer energy charge applies to the first 700 kWh each month.

Rate structure is a compromise between the complexity necessary to match cost causation to revenue recovery as precisely as possible and the level of understandability and predictability of bills and revenues desired by utilities, customers, and regulators.[34] The tension between the interest in providing revenue stability and indicating cost causation should also be considered in reasonably designing rates and selecting rate structure components.[35] Changes to rate structure may require additional metering or customer information system investment, and the cost of that investment should be weighed against the benefit of the increased complexity.

The use of blocked rates adds a level of complexity that allows demand-related costs recovery from customers without the expense of demand metering and minimal expense and complexity increases to billing systems and revenue calculations. Rates can be blocked so that demand-related costs are recovered on an annual-average sale of energy in the first block of each season. Depending on the characteristics of the system, the cost of energy may vary significantly by season or by time of day or be relatively stable. A declining-block non-summer rate design can be viewed as recovering demand costs over the first 600 kWh consumed each month, while recognizing a system's lower cost of energy for usage consumed outside of the summer season. Conversely, a flat or inclining block rate design can be viewed as recovering demand costs over the first 600 kWh consumed each month, while recognizing a system's higher cost of energy for usage consumed during the summer season. This ratio of

---

[34] Some of Empire's revenue requirement will vary year-to-year with the amount of kWh sold or the number of customers served. Some of Empire's revenue requirement will be the same each year whether consumers use an all-time high or an all-time low level of energy. The number or location of customers Empire serves will drive some of Empire's investments; while some of Empire's investments are driven by historic customer needs that are no longer in place. Some of Empire's investment is designed to efficiently serve the energy and demand needs of customers over time, and may not precisely fit the energy and demand needs of customers that receive service during a particular year.

[35] For purposes of rate design, cost causation is typically deemed as the distribution of costs that results from the allocation of a vertically integrated utility's gross revenue requirement net of other revenues. It is necessary to make an exception to this general assumption in certain instances when considering costs that would not be incurred but-for a customer, such as the cost of energy purchased through the integrated energy market to serve a customer.

the first and the second block could also reflect summer peak consumption as a driver of the costs of certain demand-related investments. Importantly, different experts may reasonably view a given rate structure as being designed to accomplish different objectives.

Interclass Revenue Responsibility Recommendations

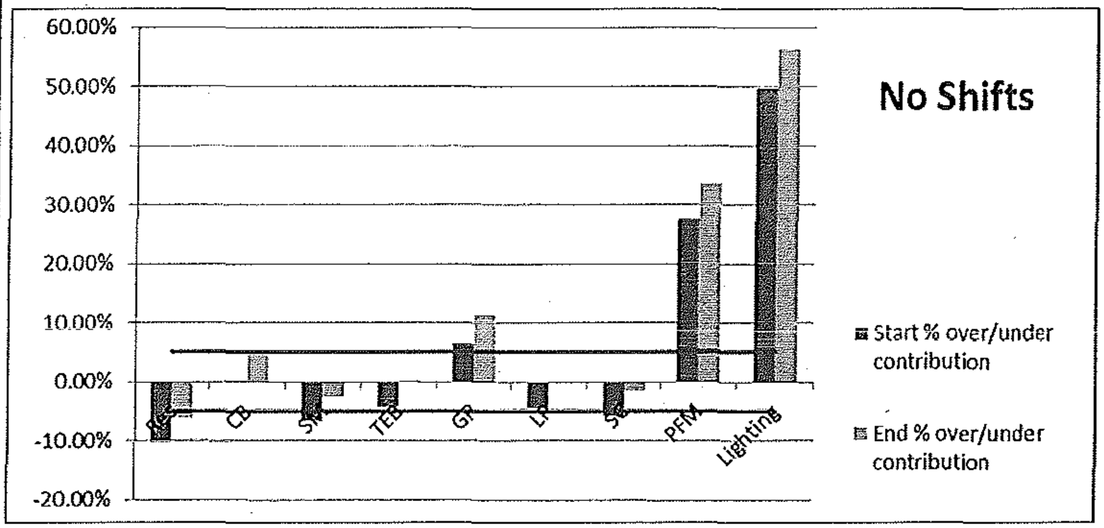
In providing its rate design recommendation, Staff will recommend revenue-neutral shifts so that once the rate increase has been applied, a given class does not underpay by greater than 5% of its revenue requirement while another class or classes overpay by greater than 5% of its revenue requirement.[36] In this case, had Staff's recommended increase of approximately $21 million dollars been applied as an equal percent to all classes, the Lighting, Feed Mill, and GP classes would be overpaying by an amount outside of the +5% band, while the Residential Class would have been underpaying by an amount outside of the -5% band. These results are provided in Table 2 and the accompanying chart.

Table 2

	Start % over/under contribution	System Average Increase + Energy Efficiency	End % over/under contribution
Residential	-10.23%	$ 9,612,803	-6.09%
Commercial Service	0.10%	$ 1,981,221	4.70%
Small Heating	-6.79%	$ 480,256	-2.49%
Electric Building	-4.29%	$ 1,727,769	0.14%
General Power	6.39%	$ 4,129,270	11.30%
Large Power	-4.35%	$ 2,434,486	-0.01%
Special Contract	-5.73%	$ 195,065	-1.48%
Feed Mill	27.71%	$ 5,243	33.56%
Lighting	49.68%	$ 347,619	56.44%

continued on next page

[36] Staff is also mindful that in the course of general rate increase cases, no class should receive a rate reduction under ordinary circumstances.



Because the Feed Mill and Lighting classes' current rates recover over 20% over the revenue requirement for those classes at an equalized rate of return, Staff recommends that the Feed Mill and Lighting classes be excluded from any rate increase in this case.[37] As indicated above, without a revenue shift, the GP class would be overpaying by an amount greater than 5% of its revenue requirement at an equalized rate of return. Another consideration is identification of which classes produce revenues that are above and below the system average rate of return. The rates of return produced by each class at current rates, and the rates of return that will result from a system-average application of the revenue requirement increase are provided in Table 9 below.

Table 9

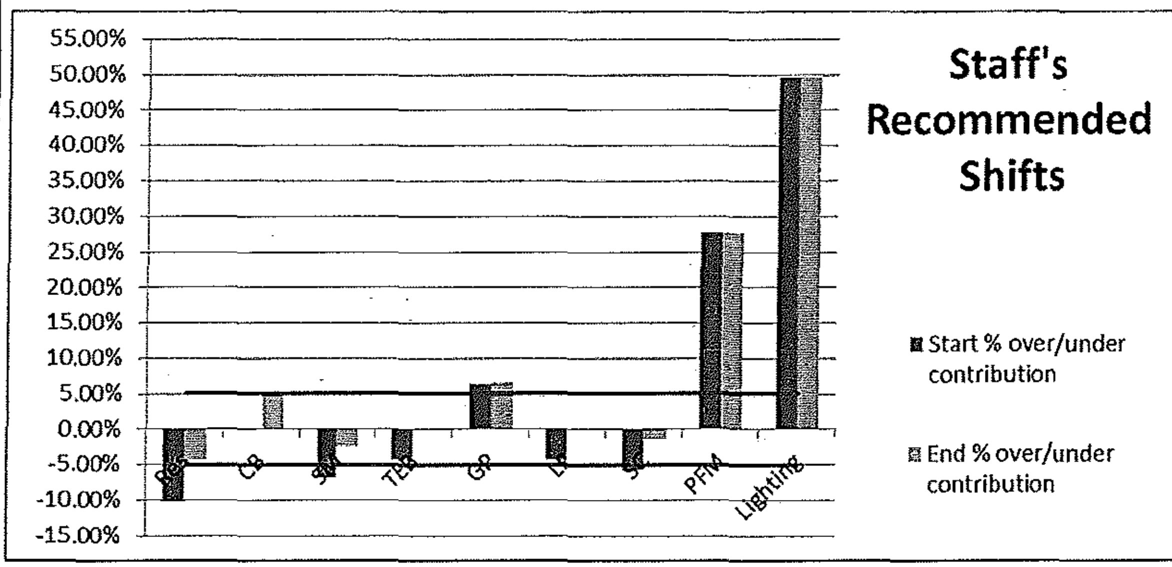
	Start RoR	System Average Increase + Energy Efficiency	End RoR
Residential	3.94%	$ 9,612,803	5.38%
Commercial Service	7.52%	$ 1,981,221	9.30%
Small Heating	5.19%	$ 480,256	6.64%
Electric Building	6.06%	$ 1,727,769	7.53%
General Power	9.81%	$ 4,129,270	11.61%
Large Power	5.89%	$ 2,434,486	7.48%
Special Contract	5.30%	$ 195,065	6.92%
Feed Mill	18.36%	$ 5,243	20.65%
Lighting	22.64%	$ 347,619	24.70%
System Average:	5.93%		7.48%

[37] Unless the ordered revenue requirement is an increase of approximately 25%, it is not necessary to adjust these class's revenue requirements on a revenue-neutral basis.

As Table 3 and its accompanying chart indicate, Staff's recommended interclass shifts in revenue responsibility will minimize the GP class's exceedance of the +5% threshold without reducing the rates paid by GP customers at a time when Empire is receiving an overall rate increase. It will also bring individual class rates of return closer to the system average.[38]

Table 3

	Revenue Responsibility Shift	Retail Increase + Energy Efficiency	End % over/under contribution	End RoR	% Increase
Residential	$3,855,000	$ 9,954,656	-4.28%	6.00%	6.62%
Commercial Service	$0	$ 2,015,241	4.78%	9.33%	4.68%
Small Heating	$0	$ 488,472	-2.41%	6.67%	4.69%
Electric Building	$0	$ 1,757,242	0.21%	7.55%	4.70%
General Power	-$3,855,000	$ 4,022,688	6.59%	9.89%	0.19%
Large Power	$0	$ 2,476,860	0.07%	7.51%	4.62%
Special Contract	$0	$ 198,487	-1.40%	6.95%	4.59%
Feed Mill	$0	$ 87	27.80%	18.39%	0.08%
Lighting	$0	$ -	49.68%	22.64%	0.00%



[38] At Staff's recommended revenue requirement increase, no revenue-neutral shift is indicated to reduce the revenue responsibility of the Commercial Service Class. However, if the final revenue requirement ordered by the Commission is greater than that currently recommended by Staff, it may be appropriate to make a small revenue-neutral reduction of approximately $25,000 to the CB class. This revenue would be shifted to the Residential class on a revenue-neutral basis.

Overall, these adjustments bring classes closer to cost of serving them, while still maintaining rate continuity, rate stability, and revenue stability, while minimizing rate shock to any one-customer class.[39] Staff based its recommendations for interclass shifts in revenue responsibility on its CCOS study results, Staff's review of Empire's revenue-neutral adjustments in previous general rate increases, and Staff's judgment regarding the impact of revenue shifts for all classes.

Staff's CCOS interclass revenue-responsibility recommendations are based on a scenario that assumes the Riverton 12 rate base increases considerably as part of the true-up of this case. If the Riverton 12 increase is not included in rates resulting from this case, Staff recommends that no revenue-neutral adjustments be made.

Intra-class Rate Design Recommendation

Empire's Residential, Commercial, and Small Heating rate structures and designs are generally not inconsistent with cost causation in the absence of demand metering or time-differentiated rates. Staff recommends preserving the existing relationship between rate elements with certain exceptions.

(1) 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 $2.48 to $15.00.

Costs included in the calculation of the Residential customer charge costs 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:

[39] For example, if two similar classes receive different levels of increases, customers may leave the higher-cost class in favor of the lower cost class. Then, at the next rate case, the lower-cost class will likely have a higher allocated cost of service, while the higher-cost class will likely have a lower allocated cost of service. The resulting redesign of rates would likely cause an undoing of the initial movement of customers, with the result being a seesawing of both rates and customers.

- 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
- Portion of income taxes

Staff recommends allocating services and meter costs using the same allocators that Empire used in Case No ER-2014-0351 to allocate these costs. Empire based these allocators on an Empire study that weights the number of installations taking service by class and by the cost of the meter and service used to serve that class. In addition, Staff recommends using the same allocators that Empire used for allocating meter reading costs, uncollectible accounts, customer services expense, and for allocating customer deposits. These allocators are derived using Empire studies that directly assign the costs of meter reading, uncollectible accounts, customer service expense, and customer deposits to the customer classes. The allocators are the fraction of total costs in these accounts assigned to each class, respectively.

The sum of the residential class's 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, using Staff's *Accounting Schedules* filed on March 25, 2016, resulted in a customer charge of approximately $18 per month.[40]

Staff's calculated customer charge at the fully allocated class cost of service is $18.35, if all class revenue requirements were adjusted to provide exactly the same rates of return. Staff's recommended interclass shifts will move the Residential class closer to providing the

[40] In the past rate cases, some parties have asserted that only the customer charge portion of uncollectible expense should be in the customer charge. Staff ran a CCOS example of including approximately 10% of the uncollectible expense in the Residential customer charge calculation and it reduced Staff's customer charge to approximately $17 per month per customer. This is still above Staff's proposed $15 customer charge.

same rate of return as other classes, but because Staff does not recommend moving all the way to the calculated Residential *class* cost of service, the intra-class Residential rate design could become misaligned by moving all the way to the calculated Residential *customer charge* cost of service.[41] Staff's recommendation to limit the residential customer charge to the level of $15.00 considered fully allocated cost causation, class revenue responsibilities, rate simplicity, customer rate stability, customer understandability, and public policy considerations relating to energy efficiency, and company revenue stability. In light of these considerations, $15.00 is a reasonable increase from the existing customer charge of $12.52, while giving due consideration to customer rate stability, customer understandability, and public policy considerations relating to energy efficiency, and company revenue stability.

Staff Expert/Witness: Robin Kliethermes

(2) Realignment of Corresponding Rate Schedule Elements

Staff recommends retaining the existing relationship between rate elements in Empire's remaining service classifications with two exceptions. Staff recommends the realignment of Small Heating Rate charges with the corresponding Commercial Building rate charges. Specifically Staff recommends the following Small Heating Rate charges be matched to their Commercial Building counterparts:

a. Customer Charge,

b. Summer First Block Charge,

c. Summer Second Block Charge, and

d. Non-Summer First Block Charge.

Staff also recommends realignment of the Total Electric Building customer charge with the corresponding General Power rate charge.

Staff Expert/Witness: Sarah L. Kliethermes

---

[41] A particular limiting factor in this case is that any additional shift to the Residential class from the General Power class would cause the General Power class's rates to be reduced below currently-tariffed rates.

V. Fuel and Purchased Power Adjustment Clause Tariff Sheet Recommendations

In its *Revenue Requirement Report* in this case, Staff provided its recommendations for the following issues which have an impact on Empire's fuel adjustment clause ("FAC") and FAC tariff sheets:

1. Continue Empire's FAC with modifications;
2. Include a revised Base Factor[42] in the FAC tariff sheets calculated from the Base Energy Cost[43] that the Commission includes in the revenue requirement upon which it sets Empire's general rates in this case; and
3. Order Empire to continue to provide the additional information as part of its monthly reports[44] as Empire agreed to do in the *Revised Stipulation and Agreement* filed April 8, 2015, in Case No. ER-2014-0351 and has continued to provide in its monthly reports.

Staff's method for calculating the Base Factor is shown in Appendix 2, Highly Confidential Schedule DCR - d1 of this report.

Fuel Adjustment Tariff Sheet Modifications

Staff reviewed the current Empire FAC tariff sheets that were approved by the Commission in Case No. ER-2016-0351 and became effective July 26, 2015. The current FAC tariff sheets reflect Empire's participation in the Southwest Power Pool's ("SPP") Integrated Market and account for transmission costs in a manner consistent with the way transmission costs are treated in Ameren Missouri's and Kansas City Power and Light's current FACs.

---

[42] Base Factor is defined in Empire's Original Tariff Sheet No. 17l as "BASE FACTOR ("BF"): The base factor is the base energy cost divided by net generation kWh determined by the Commission in the last general rate case.

[43] Base Energy Cost is defined in Empire's Original Revised Tariff Sheet No. 17l as "Base energy cost are ordered by the Commission in the last rate case consistent with the costs and revenues included in the calculation of the Fuel and Purchased Power Adjustment ("FPA") and include fuel costs incurred to support sales ("FC") plus purchased power costs ("PP") plus net emission costs ("E") minus off-system sales revenues ("OSSR") minus renewable energy credit revenue ("REC").

[44] Monthly reports are required by 4 CSR 240-3.161(5).

Staff proposes the following modifications to the tariff:

Replace the current Base Factor with the revised Base Factor of $0.02564 per kWh.

Replace the current voltage adjustment factors ("VAF's") with the updated VAF's of:

$$VAF_{PRIM} = 1.0464 \quad \text{and} \quad VAF_{SEC} = 1.0657$$

Other Changes to Empire's FAC Tariff Sheets

While each electric utility's FAC complies with the same Commission rules, each electric utility had unique FAC tariff sheets with unique acronyms and definitions. This issue was addressed in Empire's last two general rate cases, and the Commission-approved Empire FAC tariff sheets are a refinement from previous tariff sheets. However, some language included in the current Empire FAC tariff sheets does not directly apply to Empire's current operations. Office of the Public Council Witness, Lena M. Mantle addresses this issue in her Direct Testimony in this rate case.[45]

Staff proposes to work with interested parties during this rate case to remove language that is not applicable to Empire's current operations. It is not Staff's intent to change the meaning of Empire's FAC tariff sheets, but to include language which is descriptive of Empire's current operations.

Revised Base Factor

Staff calculated the Base Factor of $0.02564 per kWh. This is a decrease from the current Base Factor of $0.02684 per kWh established in Case No. ER-2014-0351, which is a further decrease from the previous Base Factor of $0.02831 established in Case No. ER-2012-0345. Staff used the Base Energy Costs and Revenues from Staff's accounting, fuel model, and fuel and purchased power work papers developed in this rate case when calculating the Base Factor.

Staff developed the Base Energy Costs and Revenues using its fuel model dispatch to calculate Empire's fuel and purchased power costs and off-system sales revenues prior to the conversion of the Riverton 12 unit from a combustion turbine to a combined cycle plant. The Riverton 12 combined cycle plant is currently being constructed and is not expected to be

[45] Direct Testimony of Lena M. Mantle, page 8 line 10 through page 9 line 8.

operational until June 1, 2016. Staff will update its recommended Base Factor when Staff's Base Energy Costs and Revenues are updated for the true-up audit for this rate case to include operation of Riverton 12 as a combined cycle plant.

Revised Base Factor Calculation

Staff calculated the Base Factor of $0.02564 per kWh using the Base Energy Costs and Revenues from Staff's accounting schedules found in Staff's COS Report in this rate case. Appendix 2, Highly Confidential Schedule DCR - d1 is Staff's calculation of the Base Factor. The Base Factor calculation is broken down into fuel costs incurred to support sales, purchased power energy costs, native load costs, net emission allowances costs, transmission costs, net auction revenue rights and transmission congestion rights (ARR/TCR), revenues from off-system sales and renewable energy credit revenues.

Fuel Costs Incurred to Support Sales

Fuel costs incurred to support the sale of total energy generated by Empire include the variable cost of fuel used in the production of electricity and includes combustion product disposal revenues and expenses and the expenses for air quality control systems (AQCS) consumables. Staff has excluded the administrative, labor, convention, and seminar expenses that are also excluded in Empire's current FAC. In addition, Staff has excluded the labor component found in other undistributed and unit train costs. Staff has excluded these costs because Empire's FAC is designed to flow through variable fuel and purchased power expenses, emission allowance expenses and revenues, not administrative, seminar, and labor expenses. Staff combined these costs, which equal **_______ **, and made a negative adjustment to Staff's calculation to remove the administrative, seminar and labor expenses from fuel costs incurred to support sales. The amount of fuel costs incurred to support sales found in Staff's accounting, and fuel and purchased power work papers was used in the Base Factor calculation.

Purchased Power Energy Costs

Staff's Base Factor calculation includes the purchased power energy costs from long term purchased power agreements ("PPAs") for energy from the Plum Point, Elk River, and

NP

Meridian facilities. Purchased power energy costs also includes variable Operations and Maintenance ("O&M") cost from the 50 MW Plum Point contract. These purchased power energy costs are found in Staff's fuel and purchased power work papers and variable O&M costs from the 50 MW Plum Point contract are found in Empire Witness Todd Tartar's work papers.

Native Load Cost

Native load cost is the cost of energy purchased through the Southwest Power Pool's Integrated Market to meet Empire's native load. Native load costs are found in Staff's fuel model summary work papers.

Net Emission Allowances

The amount of net emission allowance costs found in Staff's accounting work papers was used in the Base Factor calculation.

Transmission

Transmission costs used to transmit energy from non-company sources to Empire's service territory are included in the FAC. These costs are developed using Staff's accounting and fuel model summary work papers. Staff excluded SPP Schedule 1-A, Tariff Administration Service, and SPP Schedule 12, FERC Assessment Charge. These charges are excluded in the current FAC tariff sheets and are administrative costs, not variable fuel and purchased power costs.

Net ARR/TCR

Auction revenue rights and transmission congestion rights are components of Empire's current FAC and are included in the Base Factor calculation. The amount is found in Staff accounting work papers.

Renewable Energy Credit Revenue ("REC")

The amount of Renewable Energy Credit Revenues found in Staff's accounting work papers was used in the Base Factor calculation.

Revenue from Off-System Sales

Energy from Empire's generation resources is sold into the SPP's Integrated Market. Staff's Base Factor includes all revenues from these sales but excludes revenues from full and partial requirements sales to municipalities that are served through bilateral contracts with Empire.[46] Revenue from Off-System Sales is taken from Staff's fuel model summary work papers.

Revised FAC Voltage Adjustment Factors

As provided in Staff's *Revenue Requirement Report*, filed in this case, Staff witness Alan J. Bax used the information in Empire's line loss study in developing the following primary and secondary voltage level adjustment factors:[47]

Voltage Level	Voltage Adjustment Factor
Primary	1.0464
Secondary	1.0657

These voltage adjustment factors adjust for the energy losses experienced in the delivery of electricity from the generator to customers with primary and secondary voltage levels. These factors will be utilized in Staff's determination of a Fuel Adjustment Rate (FAR), applicable to the individual voltage service classification of a particular customer in the corresponding FAC tariff sheets.

Staff Expert/Witness: David C. Roos

[46] Empire serves the municipalities of Chetopa, Lockwood, Mt. Vernon, and Monett through bilateral contracts.

[47] Staff's *Revenue Requirement Report*, page 137.

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of The Empire District Electric Company's Request for Authority to Implement a General Rate Increase for Electric Service	))))	Case No. ER-2016-0023

AFFIDAVIT OF ROBIN KLIETHERMES

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

COMES NOW ROBIN KLIETHERMES and on her oath declares that she is of sound mind and lawful age; that she contributed to the foregoing Staff Report - Rate Design and Class Cost-of-Service; and that the same is true and correct according to her best knowledge and belief.

Further the Affiant sayeth not.

Robin Kliethermes

ROBIN KLIETHERMES

JURAT

Subscribed and sworn before me, a duly constituted and authorized Notary Public, in and for the County of Cole, State of Missouri, at my office in Jefferson City, on this 7th day of April 2016.

D. SUZIE MANKIN
Notary Public - Notary Seal
State of Missouri
Commissioned for Cole County
My Commission Expires: December 12, 2016
Commission Number: 12412070

D Suzie Mankin

Notary Public

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of The Empire District Electric Company's Request for Authority to Implement a General Rate Increase for Electric Service	))))	Case No. ER-2016-0023

AFFIDAVIT OF SARAH L. KLIETHERMES

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

COMES NOW SARAH L. KLIETHERMES and on her oath declares that she is of sound mind and lawful age; that she contributed to the foregoing Staff Report - Rate Design and Class Cost-of-Service; and that the same is true and correct according to her best knowledge and belief.

Further the Affiant sayeth not.

Sarah L. Kliethermes

SARAH L. KLIETHERMES

JURAT

Subscribed and sworn before me, a duly constituted and authorized Notary Public, in and for the County of Cole, State of Missouri, at my office in Jefferson City, on this 7th day of April 2016.

D. SUZIE MANKIN
Notary Public - Notary Seal
State of Missouri
Commissioned for Cole County
My Commission Expires: December 12, 2016
Commission Number: 12412070

D. Suzie Mankin
Notary Public

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of The Empire District Electric Company's Request for Authority to Implement a General Rate Increase for Electric Service	))))	Case No. ER-2016-0023

AFFIDAVIT OF DAVID C. ROOS

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

COMES NOW DAVID C. ROOS and on his oath declares that he is of sound mind and lawful age; that he contributed to the foregoing Staff Report - Rate Design and Class Cost-of-Service; and that the same is true and correct according to his best knowledge and belief.

Further the Affiant sayeth not.

David C. Roos

DAVID C. ROOS

JURAT

Subscribed and sworn before me, a duly constituted and authorized Notary Public, in and for the County of Cole, State of Missouri, at my office in Jefferson City, on this 7th day of April 2016.

D. SUZIE MANKIN
Notary Public - Notary Seal
State of Missouri
Commissioned for Cole County
My Commission Expires: December 12, 2016
Commission Number: 12412070

D Suzie Mankin

Notary Public

MISSOURI PUBLIC SERVICE COMMISSION

STAFF REPORT

RATE DESIGN

AND

CLASS COST-OF-SERVICE

APPENDIX 1

Staff Credentials

THE EMPIRE DISTRICT ELECTRIC COMPANY

CASE NO. ER-2016-0023

Jefferson City, Missouri
April 2016

APPENDIX 1

STAFF CREDENTIALS

TABLE OF CONTENTS

Robin Kliethermes

Present Position:

I am a Regulatory Economist in the Tariff and Rate Design Unit, Operational Analysis Department, Commission Staff Division, of the Missouri Public Service Commission. I have been employed by the Missouri Public Service Commission since March of 2012. In May of 2013, I presented on Class Cost of Service and Cost Allocation to the National Agency for Energy Regulation of Moldova (ANRE) as part of the National Association of Regulatory Utility Commissioners (NARUC) Energy Regulatory Partnership Program. I also serve on the Electric Meter Variance Committee.

Educational Background and Work Experiénce:

I have a Bachelor of Science degree in Parks, Recreation and Tourism with a minor in Agricultural Economics from the University of Missouri – Columbia in 2008, and a Master of Science degree in Agricultural Economics from the same institution in 2010. Prior to joining the Commission, I was employed by the University of Missouri Extension as a 4-H Youth Development Specialist and County Program Director in Gasconade County.

Additionally, I completed two online classes through Bismarck State College: Energy Markets and Structures (ENRG 420) in December, 2014 and Energy Economics and Finance (ENRG 412) in May, 2015.

Previous Testimony of Robin Kliethermes

Case No.	Company	Type of Filing	Issue
ER-2012-0166	Ameren Missouri	Staff Report	Economic Considerations
ER-2012-0174	Kansas City Power& Light	Staff Report	Economic Considerations
ER-2012-0175	KCP&L Greater Missouri Operations Company	Staff Report	Economic Considerations & Large Power Revenues
ER-2012-0345	The Empire District Electric Company	Staff Report	Economic Considerations, Non-Weather Sensitive Classes & Energy Efficiency
HR-2014-0066	Veolia Kansas City	Staff Report	Revenue by Class and Class Cost of Service
GR-2014-0086	Summit Natural Gas	Staff Report	Large Customer Revenues
GR-2014-0086	Summit Natural Gas	Rebuttal	Large Customer Revenues
EC-2014-0316	City of O'Fallon Missouri and City of Ballwin, Missouri v. Union Electric Company d/b/a Ameren Missouri	Staff Memorandum	Overview of Case
EO-2014-0151	KCP&L Greater Missouri Operations Company	Staff Recommendation	Renewable Energy Standard Rate Adjustment Mechanism (RESRAM)
ER-2014-0258	Ameren Missouri	Staff Report	Rate Revenue by Class, Class Cost of Service study, Residential Customer Charge
ER-2014-0258	Ameren Missouri	Rebuttal	Weather normalization adjustment to class billing units
ER-2014-0258	Ameren Missouri	Surrebuttal	Residential Customer Charge and Class allocations
ER-2014-0351	The Empire District Electric Company	Staff Report	Rate Revenue by Class, Class Cost of Service study, Residential Customer Charge
ER-2014-0351	The Empire District Electric Company	Rebuttal & Surrebuttal	Residential Customer, Interruptible Customers

Previous Testimony of Robin Kliethermes

Case No.	Company	Type of Filing	Issue
ER-2014-0370	Kansas City Power & Light	Staff Report	Rate Revenue by Class, Class Cost of Service study, Residential Customer Charge
ER-2014-0370	Kansas City Power & Light	Rebuttal & Surrebuttal	Class Cost of Service, Rate Design, Residential Customer Charge
ER-2014-0370	Kansas City Power & Light	True-Up Direct & True-Up Rebuttal	Customer Growth & Rate Switching
EE-2015-0177	Kansas City Power & Light	Staff Recommendation	Electric Meter Variance Request
EE-2016-0090	Ameren Missouri	Staff Recommendation	Tariff Variance Request
EO-2016-0100	KCP&L Greater Missouri Operations Company	Staff Recommendation	RESRAM Annual Rate Adjustment Filing
ET-2016-0185	Kansas City Power & Light	Staff Recommendation	Solar Rebate Tariff Change
ER-2016-0023	The Empire District Electric Company	Staff Report	Rate Revenue by Class

Sarah L. Kliethermes

MoPSC Employment Experience

Regulatory Economist III (July 2013 – Present)
Tariff and Rate Design Unit, Operational Analysis Department, Commission Staff Division, of the Missouri Public Service Commission. In this position my duties include providing analysis and recommendations in the areas of RTO and ISO transmission, rate design, class cost of service, tariff compliance and design, and energy efficiency mechanism and tariff design. I also continue to provide legal advice and assistance regarding generating station and environmental control construction audits and electric utility regulatory depreciation.

My prior positions in the Commission's General Counsel's Office, which was reorganized as the Staff Counsel's Office, consisted of leading major rate case litigation and settlement and presenting Staff's position to the Commission, and providing legal advice and assistance primarily in the areas of depreciation, cost of service, class cost of service, rate design, tariff issues, resource planning, accounting authority orders, construction audits, rulemakings and workshops, fuel adjustment clauses, document management and retention, and customer complaints. Those positions were:

Senior Counsel (September 2011 – July 2013)
Associate Counsel (September 2009 – September 2011)
Legal Counsel (September 2007 – September 2009)
Legal Intern (May 2006 – September 2007)

Testimony

Contributor to Contributor to Staff Cost of Service Report, regarding special contract tariff revenues in Case No. ER-2016-0023, In the Matter of The Empire District Electric Company's Request for Authority to File Tariffs to Increase Rates.

Provided at hearing, as well as prefiled Rebuttal concerning retail rate impact and public interest concerning Case No. EA-2015-0146, Application of Ameren Transmission Company of Illinois for Other Relief or in the Alternative, a Certificate of Public Convenience and Necessity Authorizing it to Construct, Install, Own, Operate, Maintain and Otherwise Control and Manage a 345,000-volt Electric Transmission Line from Palmyra, Missouri, to the Iowa Border and Associated Substation near Kirksville, Missouri.

Contributor to Staff recommendations concerning Case No. EA-2015-0145, Application of Ameren Transmission Company of Illinois for Other Relief or in the Alternative, a Certificate of Public Convenience and Necessity Authorizing it to Construct, Install, Own, Operate, Maintain and Otherwise Control and Manage a 345,000-volt Electric Transmission Line in Marion County, Missouri and an Associated Switching Station Near Palmyra, Missouri.

Contributor to Staff Class Cost of Service and Rate Design Report, regarding Class Cost of Service; prefiled Rebuttal and Surrebuttal, regarding Class Cost of Service and marginal energy cost, in Case No. ER-2014-0370, In the Matter of Kansas City Power & Light Company's Request for Authority to File Tariffs to Increase Rates.

Provided at hearing, as well as deposed, as well as prefiled Rebuttal, Supplemental Direct, and Rebuttal to Supplemental Direct, regarding marginal revenue calculation, throughput disincentive, earnings opportunity and performance incentive, and customer-related issues, in Case No. ER-2015-0055, Union Electric Company d/b/a Ameren Missouri application under the Missouri Energy Efficiency Investment Act.

Provided at hearing, as well as contributor to Contributor to Staff Cost of Service Report, regarding special contract tariff revenues, and Staff Class Cost of Service and Rate Design Report, regarding Class Cost of Service and miscellaneous tariff issues; prefiled Rebuttal and Surrebuttal, regarding Class Cost of Service and special contracts, in Case No. ER-2014-0351, In the Matter of The Empire District Electric Company's Request for Authority to File Tariffs to Increase Rates.

Provided at hearing and deposed, as well as contributor to Staff Cost of Service Report, regarding Noranda revenues, and Staff Class Cost of Service and Rate Design Report, regarding Class Cost of Service; prefiled Rebuttal and Surrebuttal, regarding Class Cost of Service, incremental cost of energy, and Noranda rate design, in Case No. ER-2014-0258, In the Matter of Union Electric Company d/b/a Ameren Missouri for Authority to File Tariffs to Increase Rates.

Provided at hearing, as well as prefiled Rebuttal and Surrebuttal, regarding energy price efficiency and transmission, in Case No. EA-2014-0207, Application of Grain Belt Express Clean Line LLC for a Certificate of Convenience and Necessity.

Contributor to Staff recommendation concerning Ameren Missouri municipal lighting, in Case No. EC-2014-0316, City of O'Fallon, Missouri, and City of Ballwin, Missouri, Complainants v. Union Electric Company d/b/a Ameren Missouri, Respondent.

Contributor to Staff Report, regarding a requested Certificate of Convenience and Necessity, a requested Special Contract tariff sheet, and tariff review, in Case No. HR-2014-0066, In the Matter of Veolia Energy Kansas City, Inc for Authority to File Tariffs to Increase Rates.

Provided at hearing, as well as prefiled Rebuttal and Surrebuttal, regarding average wholesale energy prices, in Case No. EC-2014-0224, Noranda Aluminum, Inc., et al., Complainants, v. Union Electric Company d/b/a Ameren Missouri, Respondent.

Rebuttal, regarding DSIM tariff design, margin rate calculation, and customer-related issues, in Case No. ER-2014-0095, Kansas City Power & Light application under the Missouri Energy Efficiency Investment Act. Case resolved by stipulation.

Contributor to Staff recommendation concerning KCP&L Greater Missouri Operations Company's Application for a Renewable Energy Standard Rate Adjustment Mechanism, in Case No. EO-2014-0151, addressing issues of customer notice and tariff design. Staff recommendation to approve compliance tariffs.

Related Training and Experience

Participant in Missouri's Comprehensive Statewide Energy Plan working group on Energy Pricing and Rate Setting Processes.

Presented:
Fundamentals of Ratemaking at the MoPSC (October 8, 2014)
Ratemaking Basics (Sept. 14, 2012)

Attended:
Net Metering presented by Ralph Zarumba (December, 9, 2014)
Fourth Annual Public Utility Law Symposium (October 17, 2014)
Electricity Energy Storage Sources (August 29, 2014)
Combined Heat & Power: Planning, Design and Operation (August 11, 2014)
Today's U.S. Electric Power Industry, the Smart Grid, ISO Markets & Wholesale Power Transactions (July 29-30)
MISO Markets & Settlements Training for OMS and ERSC Commissioners & Staff (Jan. 27 – 28, 2014)
Validating Settlement Charges in New SPP Integrated Marketplace (July 22, 2013)
PSC Transmission Training (May 14 – 16, 2013)
Grid School (March 4 – 7, 2013)
Specialized Technical Training - Electric Transmission (April 18 – 19, 2012)
Legal Practice Before the Missouri Public Service Commission (Sept. 1, 2011)
Renewable Energy Finance Forum (Sept. 29 – Oct 3, 2010)
The New Energy Markets: Technologies, Differentials and Dependencies (June 16, 2011)
Mid-American Regulatory Conference Annual Meeting (June 5 – 8, 2011)
Utility Basics (Oct. 14 – 19, 2007)

Education

Studied Energy Transmission at Bismarck State College, online (2014 – 2015).
Licensed to Practice Law in Missouri, MoBar # 60024 (Summer 2007).
Juris Doctorate, University of Missouri, Columbia, Missouri (2004 – 2007).
Bachelor of Science in Historic Preservation, Cum Laude, minor in Architectural Design, Southeast Missouri State University, Cape Girardeau, Missouri (2002 – 2004).
2000 – 2002: Studied Architecture and English Literature at Drury University, Springfield, Missouri.
2013Economics courses at Columbia College, Jefferson City campus.

OTHER EMPLOYMENT EXPERIENCE

Law Clerk, Contracting and Organization Research Institute. Performed legal research; analyzed, described, and categorized contracts.

Paid Intern, Southeast Missouri State University. Accessioned and organized artifact collections for the Missouri Department of Natural Resources, Division of State Parks and Historic Sites.

Intermediate Clerk, Missouri Department of Elementary and Secondary Education. Responsibilities included organizing and managing various forms of data.

David C. Roos

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

Educational Background and Work Experience:

In May 1983, I graduated from the University of Notre Dame, Notre Dame, Indiana, with a Bachelor of Science Degree in Chemical Engineering. I also graduated from the University of Missouri in December 2005, with a Master of Arts in Economics. I have been employed at the Missouri Public Service Commission as a Regulatory Economist III since March 2006. I began my employment with the Commission in the Economics Analysis section where my responsibilities included class cost of service and rate design. In 2008, I moved to the Energy Resource Analysis section where my testimony and responsibility topics include energy efficiency, resource analysis, and fuel adjustment clauses. Prior to joining the Public Service Commission I taught introductory economics and conducted research as a graduate teaching assistant and graduate research assistant at the University of Missouri. Prior to the University of Missouri, I was employed by several private firms where I provided consulting, design, and construction oversight of environmental projects for private and public sector clients.

Previous Cases

Company	Case No.
Empire District Electric Company	ER-2006-0315
AmerenUE	ER-2007-0002
Aquila Inc.	ER-2007-0004
Kansas City Power and Light	ER-2007-0291
AmerenUE	EO-2007-0409

cont'd David C. Roos

Company	Case No.
Empire District Electric Company	ER-2008-0093
Kansas City Power and Light	ER-2008-0034
Greater Missouri Operations	HR-2008-0340
Greater Missouri Operations	ER-2009-0091
Greater Missouri Operations	EO-2009-0115
Greater Missouri Operations	EE-2009-0237
Greater Missouri Operations	EO-2009-0431
Empire District Electric Company	ER-2010-0105
Greater Missouri Operations	EO-2010-0002
AmerenUE	ER-2010-0036
AmerenUE	ER-2010-0044
Empire District Electric Company	EO-2010-0084
Empire District Electric Company	ER-2010-0105
AmerenUE	ER-2010-0165
Greater Missouri Operations	EO-2010-0167
AmerenUE	EO-2010-0255
Greater Missouri Operations (Aquila)	EO-2008-0216
Ameren Missouri	ER-2011-0028
Empire District Electric Company	EO-2011-0066
Empire District Electric Company	EO-2011-0285
Ameren Missouri	EO-2012-0074
Greater Missouri Operations	EO-2012-0009
Ameren Missouri	EO-2012-0142
Ameren Missouri	ER-2012-0166
Greater Missouri Operations	EO-2013-0325
Ameren Missouri	EO-2013-0407
Empire District Electric Company	EO-2014-0057
Greater Missouri Operations	EO-2014-0256
Empire District Electric Company	ER-2014-0351
Greater Missouri Operations	EO-2015-0252
Kansas City Power and Light	EO-2015-0254
Empire District Electric Company	ER-2015-0214
Empire District Electric Company	ER-2016-0023
Greater Missouri Operations	EO-2016-0053

MISSOURI PUBLIC SERVICE COMMISSION

STAFF REPORT

RATE DESIGN

AND

CLASS COST-OF-SERVICE

APPENDIX 2

Other Staff Schedules

THE EMPIRE DISTRICT ELECTRIC COMPANY

CASE NO. ER-2016-0023

Jefferson City, Missouri
April 2016

NP

** **Denotes Highly Confidential Information** **

STAFF RATE DESIGN AND CLASS COST-OF-SERVICE REPORT

Class Cost-of-Service and Rate Design Overview

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

Definitions and Fundamental Concepts of Electric CCOS and Rate Design

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

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

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

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

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

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

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

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

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

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

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

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

---

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

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

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

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

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

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

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

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

1. Functionalization

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

1. Production
2. Transmission
3. Distribution
4. Customer

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

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

---

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

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

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

2. Classification

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

Schedule DCR-d1

of APPENDIX 2

HAS BEEN DEEMED

HIGHLY CONFIDENTIAL

IN ITS ENTIRETY