MISSOURI PUBLIC SERVICE COMMISSION

STAFF'S

RATE DESIGN

AND

CLASS COST-OF-SERVICE

REPORT

UNION ELECTRIC COMPANY
dba AMEREN MISSOURI

CASE NO. ER-2016-0179

Jefferson City, Missouri
December 23, 2016

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

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I. Executive Summary

Staff's direct-recommended revenue requirement increase for Union Electric Company d/b/a/ Ameren Missouri ("Ameren Missouri") is approximately $52 million, based on a rate of return ("ROR") of 8.75%, at the upper end of the return on equity ("ROE") range of 7.9% to 8.85%, as presented in the *Staff Report Revenue Requirement Cost-of-Service ("COS Report")*. This $52 million increase over current gross revenues of $2.667 billion would produce a total revenue requirement of approximately $2.719 billion, for an increase of approximately 1.9%. Staff's revenue requirement, as presented in its *Accounting Schedules* filed December 9, 2016, includes expected changes for a true-up ending December 31, 2016, based on current information. Staff will base its final 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.[1] 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

[1] 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.

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.

Ameren Missouri has eight (8) active service classifications. The service classifications are: (1) residential ("Res"), (2) small general service ("SGS"), (3) large general service ("LGS"), (4) small primary service ("SPS"), (5) large primary service ("LPS"), (6) large transmission service / industrial aluminum smelter ("LTS" and "IAS"), (7) three street and outdoor area lighting groups, and (8) the Metropolitan St. Louis Sewer District ("MSD") classification. Staff combined the LGS and SPS rate classifications and included MSD in its SGS class for purposes of its study.

Staff recommends that the allocation of any rate increase for Ameren Missouri that is ordered be accomplished with the following process:

1. Based on Staff's CCOS results at the studied revenue requirement, Staff recommends a revenue neutral shift in revenue responsibility from the Small General Service ("SGS") class to the Large Transmission Service ("LTS") class.[2]. Specifically, Staff recommends increasing the LTS class's revenue responsibility by approximately $36,000 at Staff's recommended revenue requirement, with a reduction to the SGS class's revenue responsibility of $36,000.[3]

2. Staff allocates the portion of the revenue increase/decrease that is attributable to energy efficiency ("EE") programs from Pre-MEEIA or Non-MEEIA ("Missouri Energy Efficiency Investment Act") program costs to applicable classes based on that class's percentage of program as provided by Ameren Missouri.[4]

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

4. Staff recommends the Residential customer charge be increased at the same percentage as the Residential class's revenue requirement, but only up to a total of $8.21. The current customer charge is $8.00. With that exception, Staff generally

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[2] "Revenue neutral" means that the revenue shifts among classes do not change the utility's total system revenues.

[3] Expressed as percentages, this is a 2.6% revenue neutral increase to the LTS class, and a 0.01% reduction to the SGS class.

[4] These program costs consist of the program costs for increases/decreases in the revenue requirement associated with the amortization of program costs incurred outside of Ameren Missouri's MEEIA programs.

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 3 above.

Staff further recommends that:

1. The Commission adopt Rider Fuel and Purchased Power Adjustment Clause ("FAC") tariff sheets consistent with Staff's CCOS Report.

2. The Commission order Ameren Missouri, as part of its next rate case, 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.

3. The following features maintain their existing uniformity:

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

4. Modifying the "Fuel and Purchased Power Adjustment (Rider FAC)" definition of LTS tariff Sheet No. 62 to read "Applicable to 103.5% of metered kilowatt-hours (kWh) of energy."

<u>Current Class Revenues and Cost to Serve</u>

Table 1 shows the rate revenue responsibility shifts necessary, in dollars, for the current rate revenues from each customer class to exactly match Staff's determination of Ameren Missouri's cost-of-serving that class, assuming each class provides revenues to produce an equal rate of return among classes.[5] Also shown are the over- and

[5] 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 Ameren Missouri from each customer class.

under-contributions of each class as percentages, as well as the percent change to class revenue to exactly match cost of service. The final column shows the current rate of return produced by each class.[6] 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.

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	$ 1,567,471,584	$37,055,870	-2.84%	2.92%	6.07%
SGS	$ 378,860,191	-$10,970,668	3.70%	-3.56%	8.48%
LGS/SPS	$ 1,063,535,054	$14,283,399	-1.67%	1.70%	6.40%
LPS	$ 272,047,469	$11,714,048	-5.33%	5.63%	4.86%
LTS	$ 1,893,010	$151,814	-9.74%	10.79%	2.68%
Lighting	$ 45,288,486	-$217,703	0.54%	-0.54%	7.32%

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. A "subsidy" occurs if a class fails to provide revenues sufficient to meet variable expenses.

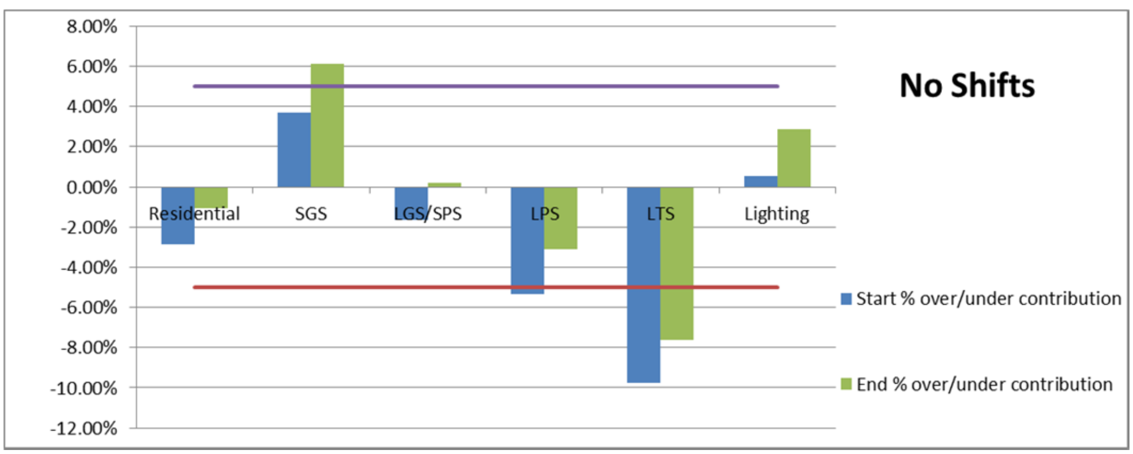
In providing its rate design recommendation, Staff recommends revenue-neutral shifts so that once the rate increase has been applied, a given class does not underpay by greater than 5% of its revenue requirement while another class or classes overpay

[6] Because other revenues, such as those produced from Ameren Missouri performing ancillary services through the MISO's integrated market, are offset against Ameren Missouri'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.

by greater than 5% of its revenue requirement.[7] In this case, if Staff's recommended increase of approximately $52 million dollars is applied as an equal percent to all classes, the SGS class would be overpaying by an amount outside of the +5% band, while the LTS class would be 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	-2.84%	$ 23,204,455	-1.06%
SGS	3.70%	$ 7,125,598	6.10%
LGS/SPS	-1.67%	$ 15,826,355	0.18%
LPS	-5.33%	$ 4,880,399	-3.11%
LTS	-9.74%	$ 32,800	-7.64%
Lighting	0.54%	$ 947,158	2.88%



As indicated above, without a revenue shift, the SGS class would be overpaying by an amount greater than 5% of its revenue requirement at an equalized rate of return.[8] These recommended revenue neutral interclass shifts mitigate the misalignment of the revenues

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

[8] 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.

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 direct-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 Ameren Missouri's 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, with 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.

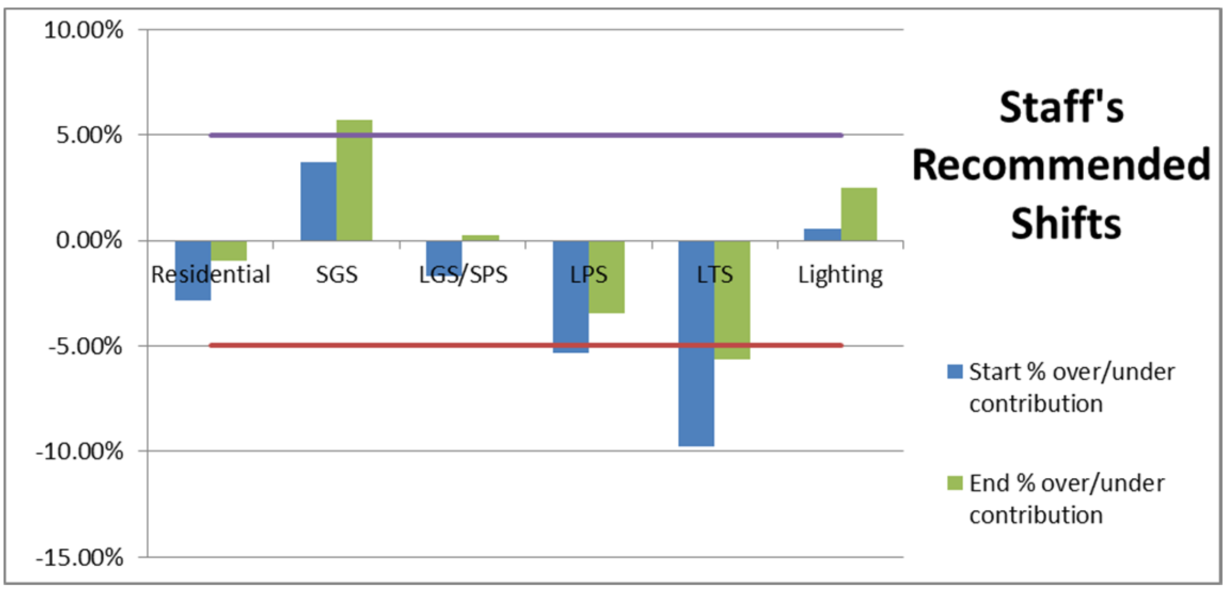
(4) Staff endeavors to provide the Commission with a rate design recommendation based on each customer class's relative cost-of-service responsibility and yield the total revenue requirement to all classes in a fair manner avoiding undue discrimination, including methods to recover both fixed and variable costs in a timely manner. This ensures Ameren Missouri 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 SGS class's exceedance of the +5% threshold without reducing the rates paid by SGS customers at a time when Ameren Missouri is receiving an overall rate increase. It will also bring individual class rates of return closer to the system average.

Table 3

	Revenue Responsibility Shift	Retail Increase + Energy Efficiency	End % over/under contribution	End RoR	% Increase to Retail Non-EE Revenues
Residential	$ -	$ 24,733,906	-0.94%	6.74%	1.95%
SGS	$ (35,851)	$ 6,003,123	5.71%	9.24%	1.94%
LGS/SPS	$ -	$ 16,401,446	0.25%	7.18%	1.95%
LPS	$ -	$ 4,057,810	-3.48%	5.63%	1.95%
LTS	$ 35,851	$ 28,138	-5.64%	4.53%	4.55%
Lighting	$ -	$ 792,343	2.50%	8.20%	1.95%
	System Average:			7.08%	1.95%



Overall, these adjustments bring classes closer to the cost of serving them, while still maintaining rate continuity, rate stability, and revenue stability, and while minimizing rate shock to any one-customer class.[9] Staff bases its recommendations for interclass shifts in

[9] 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.

revenue responsibility on its CCOS study results, Staff's review of Ameren Missouri's revenue-neutral adjustments in previous general rate increases, and Staff's expert judgment regarding the impact of revenue shifts for all classes.

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 summarized in Table 1 above and are provided in Table 4 below. 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 Ameren Missouri's customer classes. 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 to 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

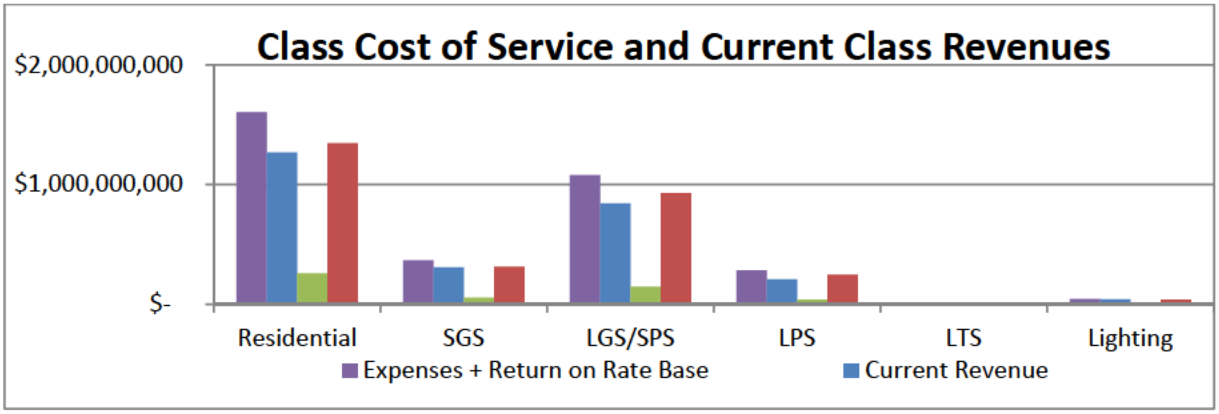
9. The percentage difference between the increased class revenues and the class revenues needed to exactly match the allocated class cost of service at equalized rates of return.

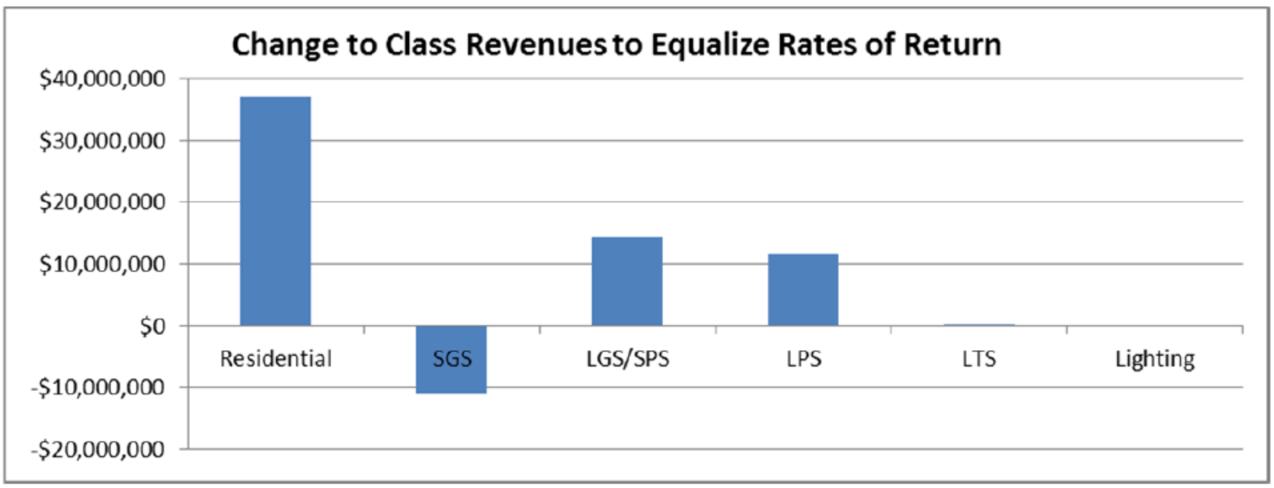
Table 4

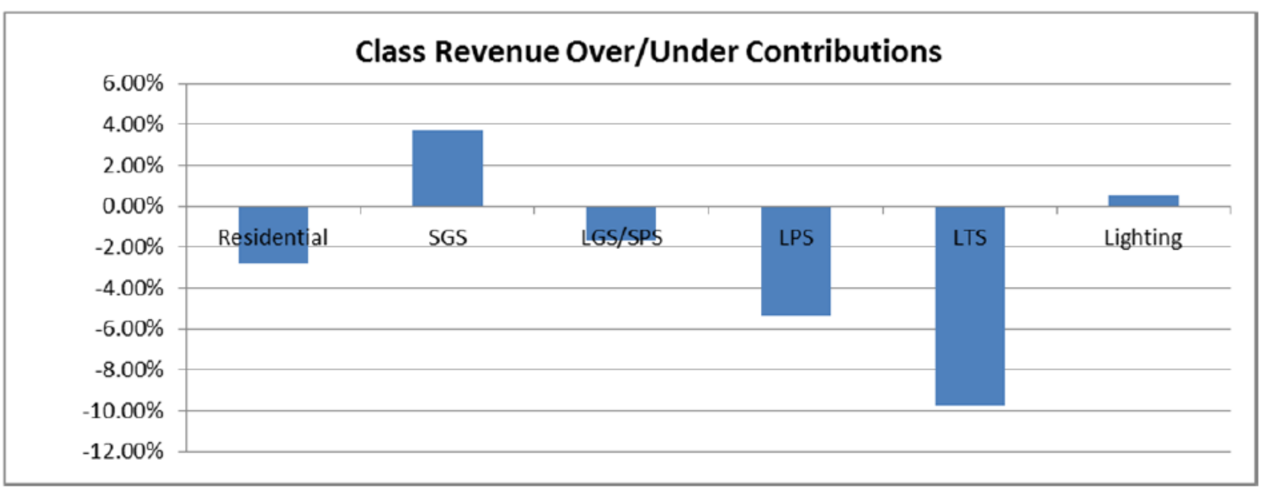
	Current Revenue *plus Allocated Other Revenue*	Revenue Change to Equalize Class Rates of Return	Start % over/under contribution	% Change to Class Revenue to Exactly Match Cost of Service	Start RoR	System Average Increase + Energy Efficiency	End RoR	Additional Revenue Change to Equalize Class Rates of Return	End % over/under contribution
Residential	$ 1,567,471,584	$37,055,870	-2.84%	2.92%	6.07%	$ 24,733,906	6.74%	$12,321,964	-0.94%
SGS	$ 378,860,191	-$10,970,668	3.70%	-3.56%	8.48%	$ 6,003,822	9.24%	-$16,974,490	5.72%
LGS/SPS	$ 1,063,535,054	$14,283,399	-1.67%	1.70%	6.40%	$ 16,401,446	7.18%	-$2,118,047	0.25%
LPS	$ 272,047,469	$11,714,048	-5.33%	5.63%	4.86%	$ 4,057,810	5.63%	$7,656,238	-3.48%
LTS	$ 1,893,010	$151,814	-9.74%	10.79%	2.68%	$ 27,439	3.48%	$124,375	-7.98%
Lighting	$ 45,288,486	-$217,703	0.54%	-0.54%	7.32%	$ 792,343	8.20%	-$1,010,046	2.50%
tem Average:					6.35%		7.08%		

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 Ameren Missouri'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 Ameren Missouri'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 Ameren Missouri should receive from that class to Ameren Missouri'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.







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 Expert/Witness: Sarah L. 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 December 9, 2016, in Staff's *Revenue Requirement Report*. This data includes:

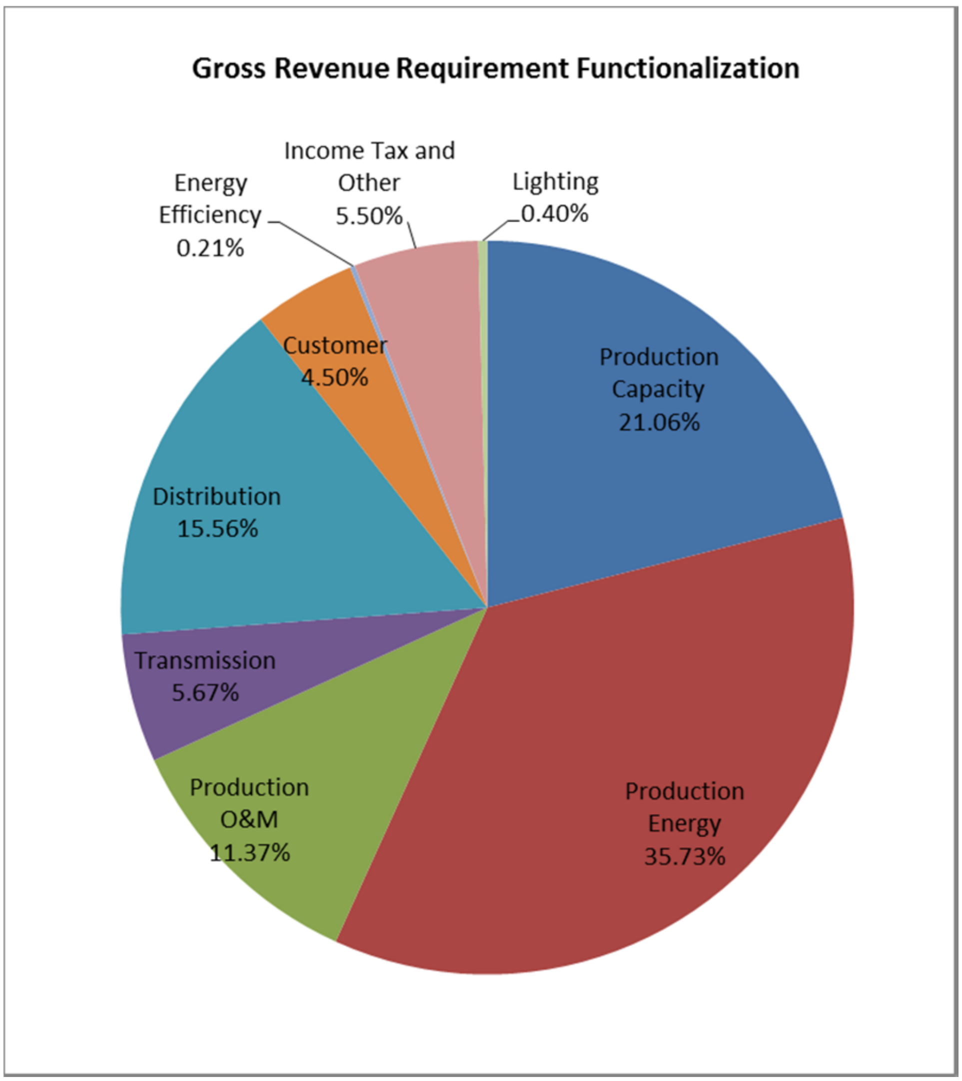
- Adjusted Missouri investment and expense data by FERC account;
- Normalized and annualized rate revenues;
- Net fuel and purchased power costs and revenues;
- Other operating and maintenance expenses;
- Depreciation and amortizations;
- Taxes; and
- For each class, Staff's determination of customer-coincidental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

In addition, Staff obtained data from Ameren Missouri, which included 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 Expert/Witness: Sarah L. Kliethermes

B. Functions

The major functional cost categories Staff used in its CCOS study are Production, Transmission, Distribution, and Customer. Within the Production function, a distinction 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 5 and 6 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	SGS	LGS/SPS	LPS	LTS	Lighting	Total
Production Capacity	$ 325,818,306	$ 78,060,076	$ 239,979,680	$ 66,009,476	$ 498,024	$ 1,619,514	$ 711,985,076
Production Energy	$ 492,558,174	$ 126,586,717	$ 442,869,294	$ 135,780,557	$ 1,070,104	$ 9,328,497	$ 1,208,193,343
Production O&M	$ 171,993,251	$ 41,531,489	$ 129,654,860	$ 35,882,023	$ 291,193	$ 5,138,480	$ 384,491,296
Transmission	$ 90,420,922	$ 21,552,967	$ 62,903,050	$ 16,222,591	$ 124,507	$ 383,391	$ 191,607,428
Distribution	$ 332,323,465	$ 58,871,682	$ 107,161,038	$ 17,129,866	$ -	$ 10,535,103	$ 526,021,154
Customer	$ 97,446,374	$ 13,716,680	$ 37,471,913	$ 1,556,886	$ 23,101	$ 1,968,066	$ 152,183,020
Energy Efficiency	$ 3,197,317	$ 325,578	$ 3,092,992	$ 651,156	$ -	$ -	$ 7,267,043
Income Tax and Other	$ 90,769,642	$ 27,244,328	$ 54,685,625	$ 10,528,963	$ 37,897	$ 2,701,190	$ 185,967,645
Lighting	$ -	$ -	$ -	$ -	$ -	$ 13,396,543	$ 13,396,543

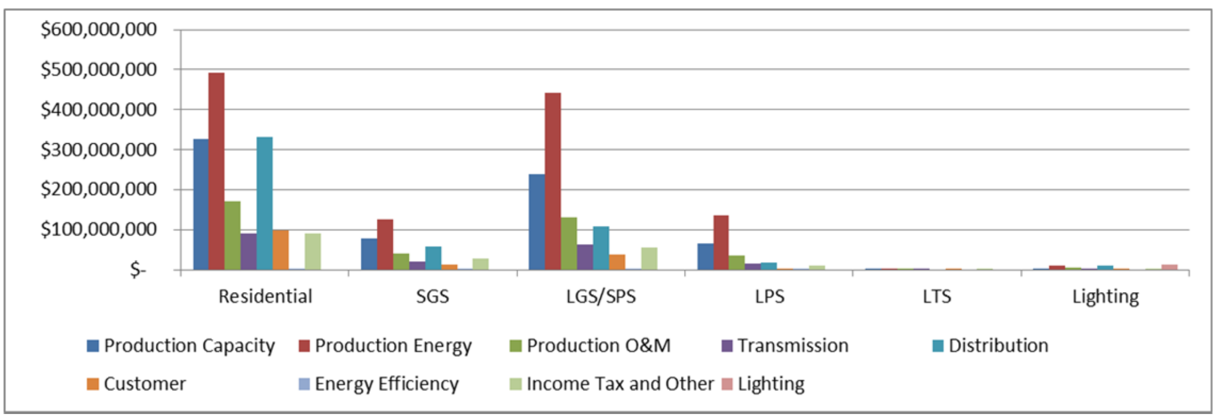


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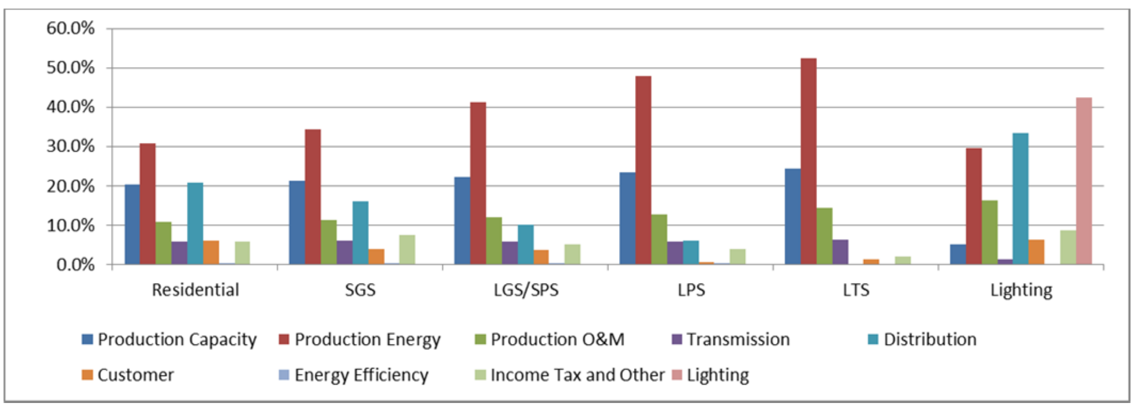
Table 6

	Residential	SGS	LGS/SPS	LPS	LTS	Lighting	Total
Production Capacity	20.3%	21.2%	22.3%	23.3%	24.4%	5.1%	21.1%
Production Energy	30.7%	34.4%	41.1%	47.9%	52.3%	29.5%	35.9%
Production O&M	10.7%	11.3%	12.0%	12.6%	14.2%	16.2%	11.4%
Transmission	5.6%	5.9%	5.8%	5.7%	6.1%	1.2%	5.7%
Distribution	20.7%	16.0%	9.9%	6.0%	0.0%	33.3%	15.6%
Customer	6.1%	3.7%	3.5%	0.5%	1.1%	6.2%	4.5%
Energy Efficiency	0.2%	0.1%	0.3%	0.2%	0.0%	0.0%	0.2%
Income Tax and Other	5.7%	7.4%	5.1%	3.7%	1.9%	8.5%	5.5%
Lighting	0.0%	0.0%	0.0%	0.0%	0.0%	42.3%	0.4%



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 Expert/Witness: Sarah L. Kliethermes

C. Allocation of Production Costs

For CCOS purposes, Staff assumes that all of Ameren Missouri's generation facilities are primarily used to produce electricity for Ameren Missouri's retail customers in Missouri.

A production-capacity (demand) or a production-energy (energy) allocator appropriately allocates Ameren Missouri's costs for plant investment and the production expenses provided on its income statement. Ameren Missouri'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 Ameren Missouri'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 Ameren Missouri's generation fleet characteristics and its load characteristics. Ameren Missouri has a relatively low proportion of small steam units to its total generation capacity, and no combined cycle units. These are the physical plant types assumed to serve intermediate load both as a practical matter and under the BIP method as described in the *NARUC Electric Utility Cost Allocation Manual* ("NARUC Manual") at page 59 *et seq*.

To ultimately reasonably allocate all production-related costs, Staff has developed a method to reasonably assign Ameren Missouri's generation assets to the BIP components for purposes of developing allocators. In practice, because Ameren participates in the MISO's Day-Ahead, Real-Time, and Ancillary Services integrated markets ("MISO IM"), its generation is dispatched as part of the larger MISO fleet. MISO's dispatch is ordered according to security-constrained economic merit, which results in price signals stacking in a manner consistent with those experienced by a utility with a generation fleet that includes the relative amounts of each base, intermediate, and peak generation units assumed in the NARUC Manual. Unlike other common CCOS methods, Staff's BIP method most reasonably assumes that some plants will run virtually year round (Base), only part of the year (Intermediate), and rarely during the year (Peak). The BIP method also recognizes the fact that Base plants tend to be more expensive to install, but 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 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 Ameren Missouri'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.

Ameren Missouri's generation fleet characteristics

Ameren Missouri's non-renewable, Base generating plants are the Callaway nuclear unit, the Sioux coal units, the Labadie coal units, and the Rush Island coal units.[10] Staff determined that the average capacity cost, net of depreciation reserve, for each of these plants. Some of these plants have 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 Ameren Missouri's Base generation is approximately $384,726/MW. However, Staff found that the average fuel cost for these plants was only $19.28/MWh. Taken together, Ameren Missouri's Base generation ran at a 84% capacity factor in Staff's fuel model.

Ameren Missouri's Intermediate generating plants are the steam units at Meramec.[11] Staff determined that the average capacity cost, net of depreciation reserve, for Ameren Missouri's Intermediate generation is approximately $321,253/MW, and the average fuel cost

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[10] 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 MISO, but aside from this sort of ancillary service activity, Staff would expect these plants to be "price takers" in the MISO market. Ameren Missouri also has wind resources, as well as solar and hydroelectric investment, including pumped storage at Taum Sauk. Staff did allocate these expenses and costs to the classes using the BIP allocators; however, Staff did not assign these expenses and costs in allocator development.

[11] In general, 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. The physical constraints of units will vary. 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 MISO 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 MISO as price takers.

for these plants was $25.70/MWh. Taken together, Ameren Missouri's Intermediate generation ran at a 23% capacity factor in Staff's fuel model.

Ameren Missouri's Peaking generating plants that ran in Staff's fuel model are predominately a number of simple-cycle gas-fired combustion turbines.[12] Staff determined that the average capacity cost, net of depreciation reserve, for Ameren Missouri's Peaking generation is only approximately $214,508/MW. However, Staff found that the average fuel cost for these plants was $27.07/MWh. Taken together, Ameren Missouri's Peaking generation that did run in Staff's fuel model ran at a 2% capacity factor.

<u>Ameren Missouri's load characteristics</u>

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. 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.

<u>Finding Class Demands</u>

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.

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

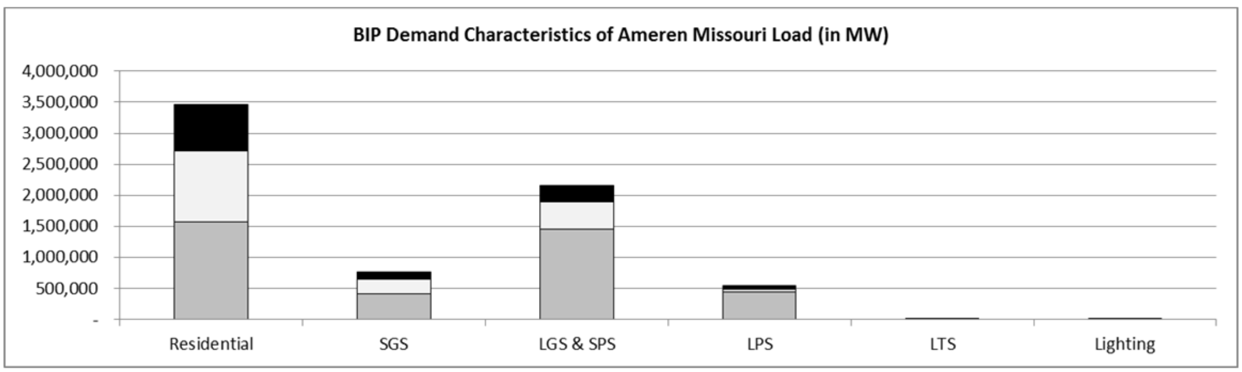
2. Staff found each class's demand in MW at the time of each month's system peak. Staff then averaged each class's 12 demands to a single MW value. That additional MW value over the base demand MW value is each class's intermediate demand. The difference between each class's base demand and its intermediate 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 Table 7 and the accompanying graph below:

Table 7

	Residential	SGS	LGS & SPS	LPS	LTS	Lighting
Base Demand	1,580,053.04	410,587.41	1,461,091.26	452,500.98	3,572.23	27,104.39
Incremental Intermediate Demand	1,140,308.27	237,845.14	431,380.54	34,007.91	173.82	-
Incremental Peak Demand	739,094.14	125,314.09	271,323.93	67,106.17	13.90	-



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.

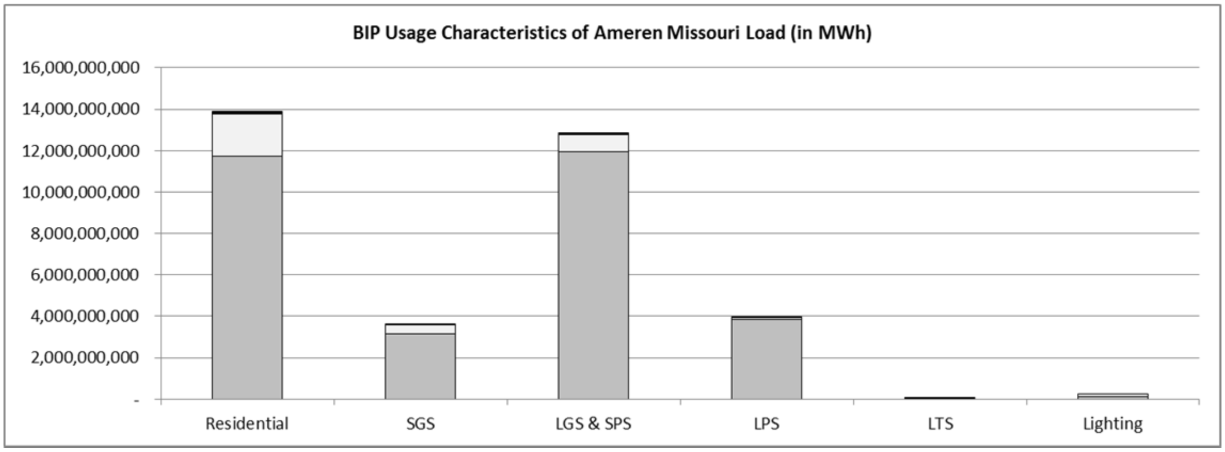
2. Staff then analyzed if in each hour a class had energy usage in excess of its intermediate demand. If so, Staff recorded that hour's energy usage up to the class's intermediate demand (less the previously allocated base usage) as that class's intermediate usage.

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 Table 8 and the accompanying graph below:

Table 8

	Residential	SGS	LGS & SPS	LPS	LTS	Lighting
Base Energy	11,715,549,002.46	3,167,592,065.21	11,943,541,314.87	3,826,839,702.47	30,292,967 68	122,675,724.89
Intermediate Energy	2,049,451,603.26	416,254,177.23	815,316,140.65	96,635,955.82	1,041,503 93	115,409,244.61
Peak Energy	114,185,273.05	22,753,610.81	75,368,197.89	51,292,913.53	43,970.12	-



Calculating BIP Allocators

Staff developed production-capacity and production-energy allocators by matching the 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, Ameren Missouri'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.[13]

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.[14]

Staff also used the assignments of generating plant to BIP components to develop allocators for Ameren Missouri'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 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 Ameren Missouri'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.

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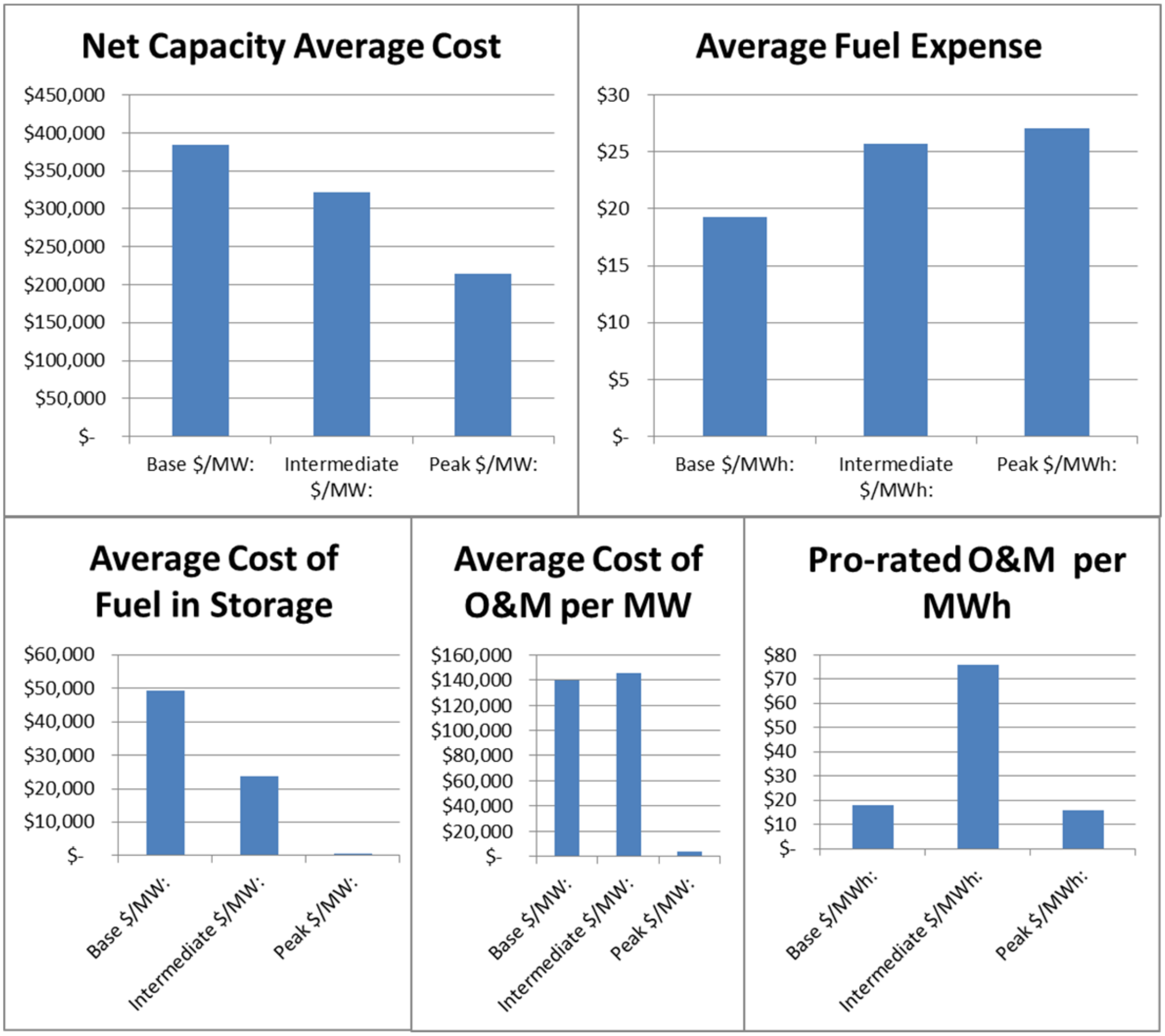
[13] A separate capacity-related allocator is used to allocate the return on investment associated with fuel stored at the various generation stations.

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



The allocators that result from applying these values to Ameren Missouri's BIP load characteristics are provided in Tables 9, 10, 11, and 12, and accompanying graphs below:

continued on next page

Table 9

BIP Installed Capacity Allocator							
	Total	Residential	SGS	LGS & SPS	LPS	LTS	Lighting
Base Capacity	$ 1,513,860,771,095	$ 607,887,023,957	$ 157,963,534,068	$ 562,119,371,078	$ 174,088,758,458	$ 1,374,327,553	$ 10,427,755,981
Incremental Intermediate Capacity	$ 1,847,694,939,342	$ 873,925,030,642	$ 208,311,095,506	$ 607,962,801,344	$ 156,292,582,333	$ 1,203,429,517	$ -
Incremental Peak Capacity	$ 1,491,769,488,594	$ 742,081,306,700	$ 165,974,944,693	$ 464,151,769,462	$ 118,754,928,781	$ 806,538,958	-
Totals:	$ 4,853,325,199,030	$2,223,893,361,300	$532,249,574,267	$1,634,233,941,883	$449,136,269,572	$3,384,296,028	$10,427,755,981
BIP Installed Capacity Allocator:		45.82%	10.97%	33.67%	9.25%	0.07%	0.21%

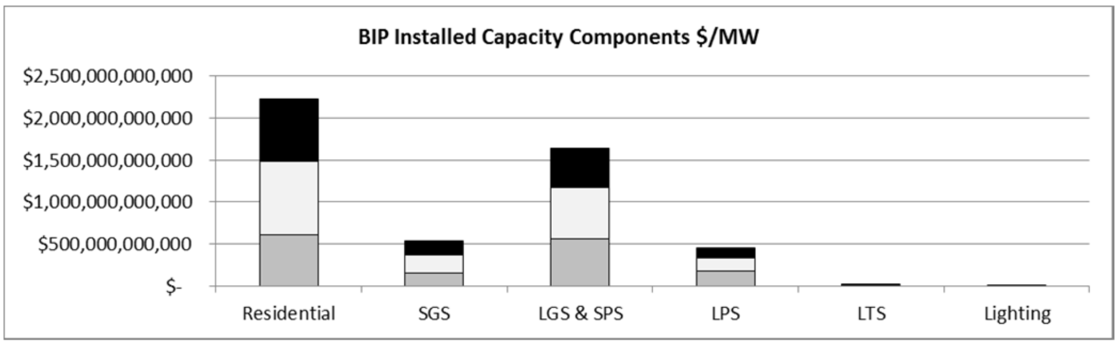


Table 10

BIP Fuel and Energy Allocator							
	Total	Residential	SGS	LGS & SPS	LPS	LTS	Lighting
Base Energy Usage	$ 593,916,293,718	$ 225,863,292,663	$ 61,067,797,464	$ 230,258,741,341	$ 73,777,388,965	$ 584,016,116	$ 2,365,057,169
Incremental Intermediate Usage	$ 89,790,051,049	$ 52,665,896,743	$ 10,696,714,907	$ 20,951,631,943	$ 2,483,307,858	$ 26,764,105	$ 2,965,735,492
Incremental Peak Usage	$ 7,137,845,886	$ 3,091,430,066	$ 616,026,872	$ 2,040,504,058	$ 1,388,694,451	$ 1,190,439	$ -
Totals:	$ 690,844,190,652	$281,620,619,472	$72,380,539,243	$253,250,877,342	$77,649,391,274	$611,970,660	$5,330,792,661
BIP Fuel and Energy Allocator:		40.76%	10.48%	36.66%	11.24%	0.09%	0.77%

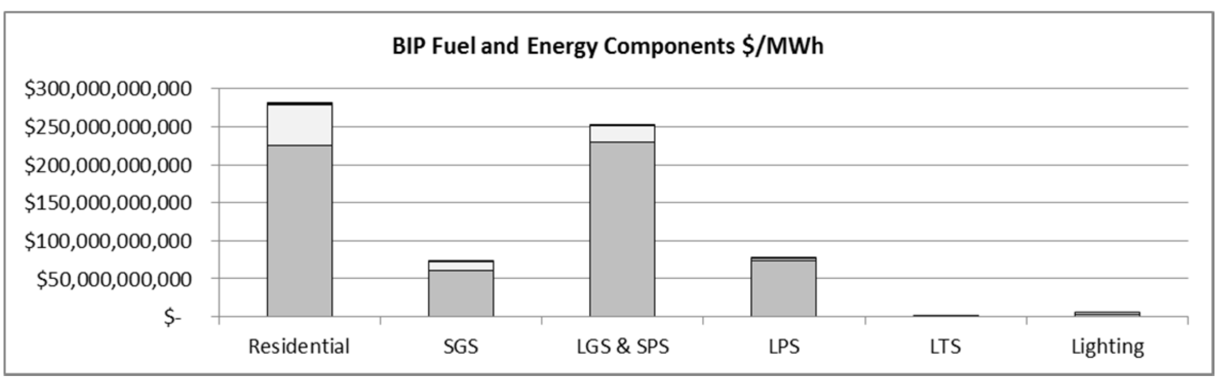


Table 11

BIP Fuel in Storage Allocator							
	Total	Residential	SGS	LGS & SPS	LPS	LTS	Lighting
Base Capacity	$ 193,987,823,414	$ 77,895,327,570	$ 20,241,625,081	$ 72,030,609,007	$ 22,307,929,487	$ 176,107,880	$ 1,336,224,390
Incremental Intermediate Capacity	$ 43,493,983,015	$ 26,900,323,544	$ 5,610,861,116	$ 10,176,437,816	$ 802,260,087	$ 4,100,452	$ -
Incremental Peak Capacity	$ 587,752,601	$ 361,145,360	$ 61,232,529	$ 132,577,669	$ 32,790,251	$ 6,792	-
Totals:	$ 238,069,559,030	$105,156,796,473	$25,913,718,725	$82,339,624,493	$23,142,979,824	$180,215,124	$1,336,224,390
BIP Fuel in Storage Allocator:		44.17%	10.88%	34.59%	9.72%	0.08%	0.56%

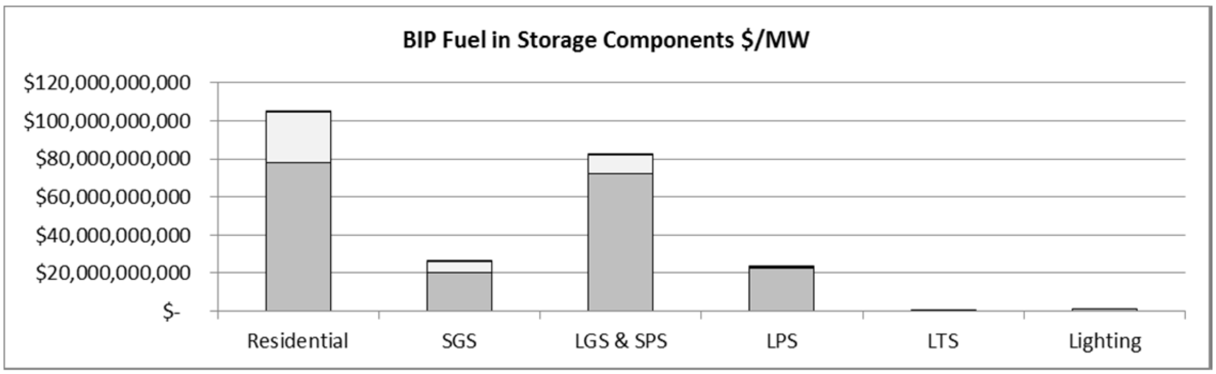
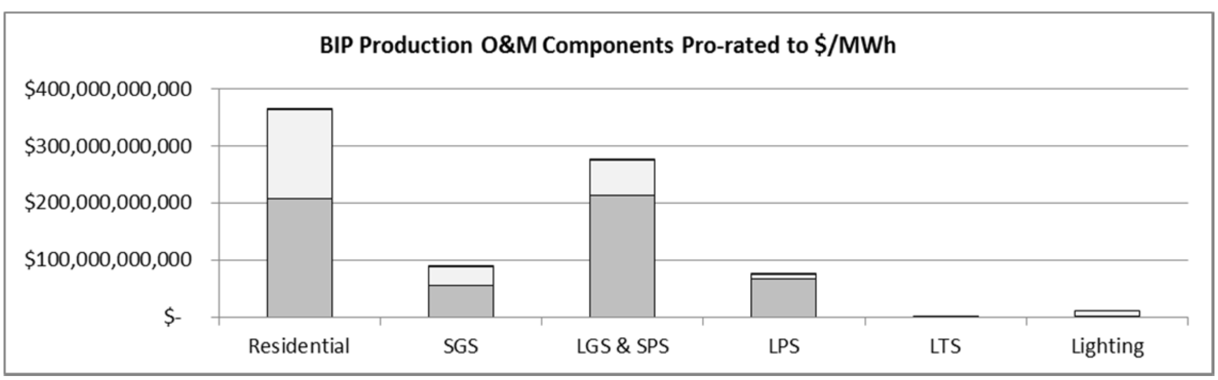


Table 12

BIP O&M Allocator							
	Total	Residential	SGS	LGS & SPS	LPS	LTS	Lighting
Base Usage	$ 549,368,128,578	$ 208,921,856,021	$ 56,487,255,803	$ 212,987,613,166	$ 68,243,532,861	$ 540,210,538	$ 2,187,660,188
Incremental Intermediate Usage	$ 264,941,562,511	$ 155,400,122,966	$ 31,562,565,431	$ 61,821,527,433	$ 7,327,442,811	$ 78,972,267	$ 8,750,931,603
Incremental Peak Usage	$ 4,180,057,384	$ 1,810,399,843	$ 360,756,973	$ 1,194,957,721	$ 813,245,703	$ 697,143	$ -
Totals:	$ 818,489,748,472	$366,132,378,830	$88,410,578,208	$276,004,098,320	$76,384,221,375	$619,879,948	$10,938,591,791
BIP O&M Allocator:		44.73%	10.80%	33.72%	9.33%	0.08%	1.34%



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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. Ameren Missouri's transmission investment and transmission costs comprise approximately 6% of the functionalized investment and costs that Staff allocated to Ameren Missouri's customer classes. Ameren Missouri'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").[15] 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 Expert/Witness: Sarah L. Kliethermes

E. Allocation of Distribution and Customer Service Costs

The distribution system converts high voltage power from the transmission system into lower primary voltage and delivers it to large industrial complexes, and further converts it into even lower secondary voltage power 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, except for the LTS class, were included in the

[15] 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.

calculation of the allocation factor for distribution substations. Staff used each class's annual non-coincident peak (as measured at substation voltage) to allocate substation costs.

Staff allocated the costs of the primary distribution facilities on the basis of each customer class' annual non-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 that distribution primary costs were allocated only to those customers that used these facilities.

Staff allocated the costs of distribution secondary investment and line transformers on the basis of each class's annual-peak demand measured 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. Coincident-peak demand is "the demand of each customer class and each customer at the hour when the overall system peak occurs." Class-peak demand is the maximum hourly demand of all customers within a specific class. Although not all customers peak at the same time, due to intra-class diversity, to achieve the class peak a significant percentage of the customers in the class will be at or near their peak. Therefore, class-peak demand will have less diversity than the class's load at the time of system peak.

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

Staff recommends allocating the costs of distribution secondary investment and line transformers on the basis of each class's annual-peak demand measured at secondary voltage.

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

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F. Allocation of Customer Related Costs

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

Staff recommends allocating distribution service lines using each class's maximum daily demand at secondary voltage.[16] Staff recommends allocating meter costs using the same allocator that Ameren Missouri used to allocate meter costs. This allocator is based on an Ameren Missouri study that weights the meter investment by class, and by the cost of the meter used to serve that class. Staff recommends using the same allocators that Ameren Missouri used for allocating meter reading costs, uncollectible accounts, and for allocating customer deposits. These three allocators are derived using Ameren Missouri's studies that directly assign the costs of meter reading, uncollectible accounts, and customer deposits to the customer classes. The allocators are the fraction of total costs of meter reading, uncollectible accounts, and customer deposits assigned to each class, respectively. Staff allocated other customer service-related accounts on customer counts or according to Ameren Missouri's CCOS study.

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[16] Staff has typically allocated certain values such as property tax on the percent of each class's previously allocated net plant. However, regarding distribution service lines, the distribution service lines reserve balance is currently greater than the distribution service lines plant balance. This alignment results in a negative net plant value associated with distribution service lines. Because use of this allocator relying on a negative plant value would result in an unreasonable allocation of costs, and the value of costs allocated is relatively large, Staff was concerned that use of the Net Plant Allocator would unreasonably allocate costs in this case in a manner that could impact the reliability of the overall costs. For this reason, Staff used each class's previously allocated percentage of gross plant for the allocation of costs typically allocated with the Net Plant Allocator. The Gross Plant Allocator results in allocation of costs that is not unreasonable, and the resulting allocation does not degrade the overall reliability of Staff's CCOS studies.

G. Revenues

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

Staff allocated other electric revenues to the rate classes depending on the source of those revenues. Staff allocated all off-system revenues from the sale of energy through the MISO IM on dollar-weighted energy, and other off-system revenues including transmission system ancillary services, were allocated on dollar-weighted capacity.

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H. Allocation of Taxes

Taxes consist of real estate and property taxes, payroll taxes, and income taxes. Ameren Missouri's investment in plant directly relate to real estate and property taxes, 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 Ameren Missouri'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 Ameren Missouri's income taxes based on class earnings.

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I. Allocation of Seasonal Energy Costs

Ameren Missouri'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 116% of modeled non-summer season wholesale energy costs. Table 13 provides the seasonal costs per class below.

Table 13

	Res.	SGS	LGS/SPS	LPS	LTS	Ltg.	Total / Average
Summer $/MWh at Market Prices used in Fuel Run (at Generation):	$ 35.26	$ 34.65	$ 33.54	$ 32.77	$ 32.49	$ 25.37	$ 34.20
Summer $/MWh at Actual Market Prices (at Generation):	$ 34.83	$ 33.69	$ 32.68	$ 32.06	$ 31 85	$ 26.24	$ 33.53
Non-Summer MWh at Generation:	8,887,632,074	2,319,952,391	8,060,835,284	2,502,367,128	21,547,883	167,913,025	21,960,247,784
Non-Summer $/MWh at Market Prices used in Fuel Run (at Generation):	$ 23.55	$ 23.72	$ 23.62	$ 23.44	$ 23 33	$ 21.94	$ 23.57
Non-Summer $/MWh at Actual Market Prices (at Generation):	$ 20.83	$ 20.90	$ 20.71	$ 20.47	$ 20.41	$ 19.47	$ 20.74
Summer % of total kWh:	27%	27%	28%	28%	25%	23%	30%
Summer % of total $ (Fuel Run):	38%	38%	38%	38%	34%	27%	38%
Summer % of total $ (Actual):	41%	40%	40%	40%	37%	30%	41%
Summer to NonSummer Index (Fuel Run):	150%	146%	142%	140%	139%	116%	145%
Summer to NonSummer Index (Actual):	167%	161%	158%	157%	156%	135%	162%

Staff recommends that as part of its next rate case, Ameren Missouri 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 Expert/Witness: Sarah L. Kliethermes

J. Energy Costs

The total cost of energy procured through the MISO Day Ahead Market for each class and the average cost of energy based on each class's load shape are provided in Table 14, below. Ancillary service, real time market, transmission, and capacity costs are not included in these amounts.

continued on next page

Table 14

	Res.	SGS	LGS/SPS	LPS	LTS	Ltg.
Cost of Energy at Market Prices used in Fuel Run:	$ 340,945,168,343	$ 88,898,120,416	$ 307,975,082,921	$ 94,580,444,210	$ 769,513,382	$ 5,044,198,333
Cost of Energy at Actual Market Prices:	$ 315,229,281,508	$ 81,437,493,760	$ 281,572,398,145	$ 86,380,183,166	$ 701,456,245	$ 4,676,085,213
MWh at Generation:	13,798,070,902	3,595,783,202	12,639,222,322	3,942,836,999	32,370,811	236,403,299
$/MWh at Market Prices used in Fuel Run (at Generation):	$ 24.71	$ 24.72	$ 24.37	$ 23.99	$ 23.77	$ 21.34
$/MWh at Actual Market Prices (at Generation):	$ 22.85	$ 22.65	$ 22.28	$ 21.91	$ 21.67	$ 19.78
MWh at Meter:	14,848,126,671	3,869,428,187	13,587,386,302	4,122,603,881	32,815,675	253,880,830
$/MWh at Market Prices used in Fuel Run (at Meter):	$ 22.96	$ 22.97	$ 22.67	$ 22.94	$ 23.45	$ 19.87
$/MWh at Actual Market Prices (at Meter):	$ 21.23	$ 21.05	$ 20.72	$ 20.95	$ 21.38	$ 18.42
Class % of Total Cost of Energy at Market Prices used in Fuel Run:	40.675%	10.606%	36.742%	11.284%	0.092%	0.602%
Class % of Total Cost of Energy at Actual Market Prices:	40.939%	10.576%	36.568%	11.218%	0.091%	0.607%

Staff Expert/Witness: Sarah L. Kliethermes

IV. Rate Design

In this case, were Staff’s recommended increase of approximately $52 million dollars applied as an equal percent to all classes, the SGS class would be over-contributing to revenue requirement by approximately 6%, while the LTS class would be underpaying by over 7.6%.

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 direct-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 Ameren Missouri's class revenue recovery through rate design. Staff endeavors to provide methods to promote revenue stability and efficiency when implementing in rates any Commission-ordered overall change in customer revenue responsibility. Staff must also balance this, to the extent possible, with 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 manner avoiding undue discrimination. This includes methods to recover both fixed and variable costs in a timely manner. This ensures Ameren Missouri 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 accomplishing the allocation of any rate increase for Ameren Missouri through the following process:

1. Based on Staff's CCOS results at the studied revenue requirement, Staff recommends a revenue neutral shift in revenue responsibility from the Small General Service ("SGS") class to the Large Transmission Service ("LTS") class.[17]. Specifically, Staff recommends increasing the LTS class's revenue responsibility by approximately $36,000 at Staff's recommended revenue requirement, with a reduction to the SGS class's revenue responsibility of $36,000.[18]

[17] "Revenue neutral" means that the revenue shifts among classes do not change the utility's total system revenues.

[18] Expressed as percentages, this is a 2.6% revenue neutral increase to the LTS class, and a 0.01% reduction to the SGS class.

2. Staff allocates the portion of the revenue increase/decrease that is attributable to energy efficiency ("EE") programs from Pre-MEEIA or Non-MEEIA ("Missouri Energy Efficiency Investment Act") program costs to applicable classes based on that class's percentage of program as provided by Ameren Missouri.[19]

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

4. Staff recommends the Residential customer charge be increased at the same percentage as the Residential class's revenue requirement, but only up to a total of $8.21. The current customer charge is $8.00. 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 3 above.

Rate Structure

Once Staff determines the revenue requirement, Staff must calculate the rates that will be charged to the utility's customers.[20] 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.

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. The tension between the interest in providing revenue stability and indicating cost causation should also

[19] These program costs consist of the program costs for increases/decreases in the revenue requirement associated with the amortization of program costs incurred outside of Ameren Missouri's MEEIA programs.

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

be considered in reasonably designing rates and selecting rate structure components.[21] 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 750 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 750 kWh consumed each month, while recognizing a system's higher cost of energy for usage consumed during the summer season. This ratio of 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.

The residential rate schedule 1(M) consists of the following elements:

- Regular Service Rates
- Optional Time of Day rates
- Customer Charge – per month
- Low-Income Pilot Program Charge – per month per season
- Energy Charge – per kWh per season
- Fuel and Purchased Power Adjustment – per kWh
- Energy Efficiency Program Charge – per kWh per season
- Energy Efficiency Investment Charge (Rider EEIC)

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[21] 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 non-residential, non-lighting rate schedules consist of the following rate groups and rate elements:

The Small General Service Rate schedule 2(M) consists of the following elements:

- Small General Service Rates
- Optional Time of Day Rates
- Customer Charge (Single or Three Phase Service) – per month
- Low-Income Pilot Program Charge – per month per season
- Summer Energy Charge – per kWh
- Winter Energy Charge – Base Energy Charge and Seasonal Energy Charge per kWh
- Fuel and Purchased Power Adjustment – per kWh
- Energy Efficiency Program Charge – per kWh per season
- Energy Efficiency Investment Charge (Rider EEIC)

The Large General Service Rate schedule 3(M) consists of the following elements:

- Large General Service Rates
- Optional Time of Day Rates
- Customer Charge – per month per season
- Low-Income Pilot Program Charge – per month per season
- Summer Energy Charge – Hours of use per kW of billing demand - per kWh per season
- Winter Energy Charge – Base Energy Charge – Hours of Use per kW of base demand and seasonal energy charge per kWh
- Demand Charge – per kW of total billing demand per season
- Fuel and Purchased Power Adjustment – per kWh
- Energy Efficiency Program Charge – per kWh per season
- Energy Efficiency Investment Charge (Rider EEIC)

The Small Primary Service Rate schedule 4(M) consists of the following elements:

- Small Primary Service Rates
- Optional Time of Day Rates
- Customer Charge – per month per season

- Low-Income Pilot Program Charge – per month per season
- Energy Charge – Hours of use per kW of billing demand - per kWh per season
- Demand Charge – per kW of total billing demand per season
- Reactive Charge – per kVar per season
- Fuel and Purchased Power Adjustment – per kWh
- Energy Efficiency Program Charge – per kWh per season
- Energy Efficiency Investment Charge (Rider EEIC)

The Large Primary Service Rate schedule 11(M) consists of the following elements:

- Large Primary Service Rates
- Optional Time of Day Rates
- Customer Charge – per month per season
- Low-Income Pilot Program Charge – per month per season
- Energy Charge – per kWh per season
- Demand Charge – per kW of billing demand per season
- Reactive Charge – per kVar per season
- Fuel and Purchased Power Adjustment – per kWh
- Energy Efficiency Program Charge – per kWh per season
- Energy Efficiency Investment Charge (Rider EEIC)

The Large Transmission Service Rate schedule 12(M) consists of the following elements:

- Large Transmission Service Rates
- Optional Time of Day Rates
- Customer Charge – per month per season
- Low-Income Pilot Program Charge – per month per season
- Energy Charge – per kWh per season
- Demand Charge – per kW of billing demand per season
- Reactive Charge – per kVar per season
- Energy Line Loss Rate – per kWh
- Fuel and Purchased Power Adjustment – per kWh
- Energy Efficiency Investment Charge (Rider EEIC)

The Lighting rate schedules are:

- Street and Outdoor Area Lighting 5(M) – Company owned
- Street and Outdoor Area Lighting 6(M) – Customer owned
- Municipal Street Lighting 7(M)
- Unmetered service
- Metered service
- Discounted rates for municipalities with franchise agreements
- Fuel and Purchased Power Adjustment – per kWh

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

Current Class Revenues and Cost to Serve

Table 1 shows the rate revenue responsibility shifts necessary, in dollars, for the current rate revenues from each customer class to exactly match Staff's determination of Ameren Missouri's cost-of-serving that class, assuming each class provides revenues to produce an equal rate of return among classes.[22] Also shown are the over- and under-contributions of each class as percentages, as well as the percent change to class revenue to

[22] 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 Ameren Missouri from each customer class.

exactly match cost of service. The final column shows the current rate of return produced by each class.[23] 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.

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	$ 1,567,471,584	$37,055,870	-2.84%	2.92%	6.07%
SGS	$ 378,860,191	-$10,970,668	3.70%	-3.56%	8.48%
LGS/SPS	$ 1,063,535,054	$14,283,399	-1.67%	1.70%	6.40%
LPS	$ 272,047,469	$11,714,048	-5.33%	5.63%	4.86%
LTS	$ 1,893,010	$151,814	-9.74%	10.79%	2.68%
Lighting	$ 45,288,486	-$217,703	0.54%	-0.54%	7.32%

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. A "subsidy" occurs if a class fails to provide revenues sufficient to meet variable expenses.

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.[24] In this case, if Staff's recommended increase

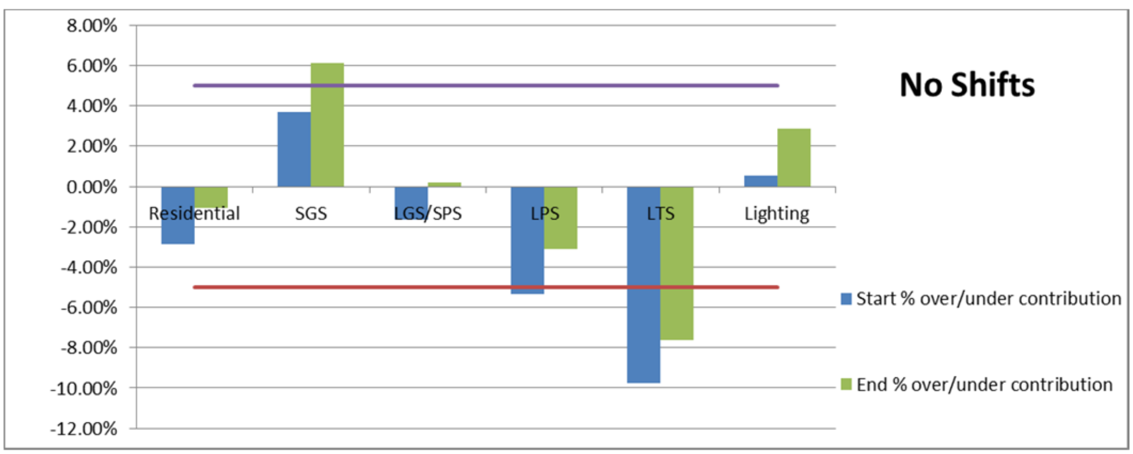
[23] Because other revenues, such as those produced from Ameren Missouri performing ancillary services through the MISO's integrated market, are offset against Ameren Missouri's cost of service, it is reasonable to include that allocation as an increase to each class's rate revenues for purposes of a CCOS study.

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

of approximately $52 million dollars is applied as an equal percent to all classes, the SGS class would be overpaying by an amount outside of the +5% band, while the LTS class would be 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	-2.84%	$ 23,204,455	-1.06%
SGS	3.70%	$ 7,125,598	6.10%
LGS/SPS	-1.67%	$ 15,826,355	0.18%
LPS	-5.33%	$ 4,880,399	-3.11%
LTS	-9.74%	$ 32,800	-7.64%
Lighting	0.54%	$ 947,158	2.88%



As indicated above, without a revenue shift, the SGS class would be overpaying by an amount greater than 5% of its revenue requirement at an equalized rate of return.[25] These recommended revenue neutral interclass shifts mitigate the misalignment of the revenues

[25] 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.

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 direct-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 Ameren Missouri's 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, with 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.

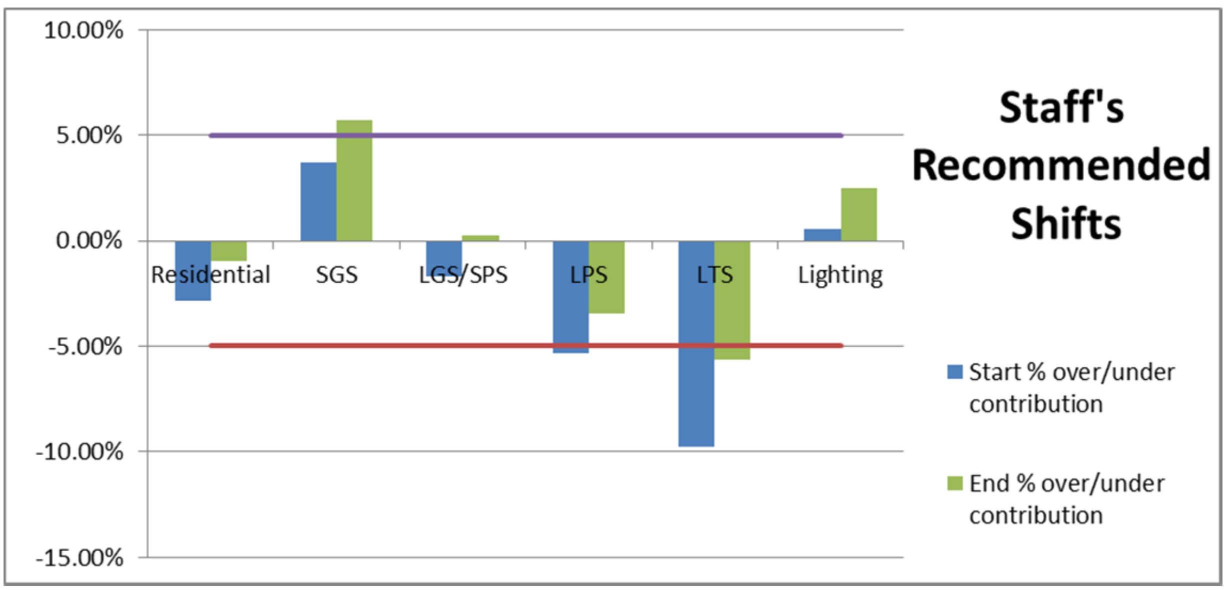
(4) Staff endeavors to provide the Commission with a rate design recommendation based on each customer class's relative cost-of-service responsibility and yield the total revenue requirement to all classes in a fair manner avoiding undue discrimination, including methods to recover both fixed and variable costs in a timely manner. This ensures Ameren Missouri 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 SGS class's exceedance of the +5% threshold without reducing the rates paid by SGS customers at a time when Ameren Missouri is receiving an overall rate increase. It will also bring individual class rates of return closer to the system average.

Table 3

	Revenue Responsibility Shift	Retail Increase + Energy Efficiency	End % over/under contribution	End RoR	% Increase to Retail Non-EE Revenues
Residential	$ -	$ 24,733,906	-0.94%	6.74%	1.95%
SGS	$ (35,851)	$ 6,003,123	5.71%	9.24%	1.94%
LGS/SPS	$ -	$ 16,401,446	0.25%	7.18%	1.95%
LPS	$ -	$ 4,057,810	-3.48%	5.63%	1.95%
LTS	$ 35,851	$ 28,138	-5.64%	4.53%	4.55%
Lighting	$ -	$ 792,343	2.50%	8.20%	1.95%
	System Average:			7.08%	1.95%



Overall, these adjustments bring classes closer to the cost of serving them, while still maintaining rate continuity, rate stability, and revenue stability, and while minimizing rate shock to any one-customer class.[26] Staff bases its recommendations for interclass shifts in

[26] 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.

revenue responsibility on its CCOS study results, Staff's review of Ameren Missouri's revenue-neutral adjustments in previous general rate increases, and Staff's expert judgment regarding the impact of revenue shifts for all classes.

Staff Expert/Witness: Sarah L. Kliethermes

Intra-class Rate Design Recommendation

Ameren Missouri'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

Ameren Missouri's current residential customer charge is set at $8.00 per month. 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 an equal percent of any final rate increase to the residential class, if such an increase is ordered by the Commission, up to a level of $8.21.

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:

- 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

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 calculated customer charge at the fully allocated class cost of service is $8.21, if all class revenue requirements were adjusted to provide exactly the same rates of return.

Staff Expert/Witness: Sarah L. Kliethermes

(2) Retention of existing Rate Design Features

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

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

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

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

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

Staff Expert/Witness: Sarah L. Kliethermes

(3) Adjustment to LTS Rider FAC billing determinant

Currently, the "Fuel and Purchased Power Adjustment (Rider FAC)" portion of LTS tariff Sheet No. 62 states the provision "Applicable to all metered kilowatt-hours (kWh) of energy," while separately a provision is made on Sheet No. 62 for an "Energy Line Loss Rate." For consistency between the impact of these provisions, Staff recommends modifying the definition of metered kWh for purposes of the LTS Rider FAC charge to read "Applicable to 103.5% of metered kilowatt-hours (kWh) of energy."

Staff Expert/Witness: Sarah L. Kliethermes

V. Fuel and Purchased Power Adjustment Clause Tariff Sheet Recommendations

Net Base Energy Costs – Base Factors

Staff proposes the Base Factor ("BF") rates reflect an additional BF period and be rebased as follows: summer BF **** $____ ****, winter 1 BF **** $____ ****, and winter 2 BF **** $____ **** cents/kWh[27] based upon an analysis of data compiled during the 12 months ending June 2016 (see Appendix 2, Schedule DEE-1[28]). Staff contends the addition of a third

[27] Months included in each corresponding BF: Summer (June – September); Winter 1 (October – January); Winter 2 (February – May).

[28] Schedule DEE-1 is included in the work papers of Staff witness Brian Wells.

BF should significantly smooth out the over/under collection Ameren Missouri experiences because of kWh usage being greatly impacted by seasonal weather. Staff will true-up its proposed BF summer and winter 1 and 2 rates in its True-up surrebuttal testimony to be filed on February 10, 2017.

Staff Expert/Witness: Dana E. Eaves

VI. Appendices

Appendix 1 - Staff Credentials

Appendix 2 - Other Staff Schedules

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of Union Electric Company d/b/a Ameren Missouri's Tariffs to Increase Its Revenues for Electric Service	)))	Case No. ER-2016-0179

AFFIDAVIT OF DANA E. EAVES

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

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

Further the Affiant sayeth not.

Dana E. Eaves

DANA E. EAVES

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 22nd day of December, 2016.

D. SUZIE MANKIN
Notary Public - Notary Seal
State of Missouri
Commissioned for Cole County
My Commission Expires: December 12, 2020
Commission Number: 12412070

D Suzie Mankin

Notary Public

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of Union Electric Company d/b/a Ameren Missouri's Tariffs to Increase Its Revenues for Electric Service	)))	Case No. ER-2016-0179

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 - 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 22nd day of December, 2016.

D. SUZIE MANKIN
Notary Public - Notary Seal
State of Missouri
Commissioned for Cole County
My Commission Expires: December 12, 2020
Commission Number: 12412070

D Suzie Mankin

Notary Public