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|---|---|
| Exhibit No.: | |
| Issue(s): | Rate Increase Allocation, CCOSS, LGS & SPS Rates, Economic Development/Infrastructure Efficiency, Electric Vehicle Rates, Time of Day Rates, Energy Efficiency Financing, LED Street Lighting, FAC Losses for LTS, Remote Meter Reading Opt Out, Seasonality of Rates |
| Witness: | William R. Davis |
| Type of Exhibit: | Rebuttal Testimony |
| Sponsoring Party: | Union Electric Company |
| File No.: | ER-2016-0179 |
| Date Testimony Prepared: | January 24, 2017 |

**MISSOURI PUBLIC SERVICE COMMISSION**

**File No. ER-2016-0179**

# RATE DESIGN
# REBUTTAL TESTIMONY

**OF**

**WILLIAM R. DAVIS**

**ON**

**BEHALF OF**

**UNION ELECTRIC COMPANY**
**d/b/a Ameren Missouri**

**St. Louis, Missouri**
**January 2017**

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# REBUTTAL TESTIMONY

# OF

# WILLIAM R. DAVIS

# FILE NO. ER-2016-0179

## I. INTRODUCTION

**Q. Please state your name and business address.**

A. My name is William ("Bill") R. Davis. My business address is One Ameren Plaza, 1901 Chouteau Avenue, St. Louis, Missouri 63103.

**Q. By whom and in what capacity are you employed?**

A. I am the Director of Energy Efficiency and Renewables for Union Electric Company d/b/a Ameren Missouri ("Ameren Missouri" or "Company").

**Q. Are you the same William R. Davis who filed direct testimony in this case?**

A. Yes, I am.

## II. PURPOSE OF TESTIMONY

**Q. What is the purpose of your rate design rebuttal testimony in this proceeding?**

A. The purpose of my rate design rebuttal testimony is to address:

1) The rate increase allocation recommendations presented by Missouri Public Service Commission Staff ("Staff"), the Office of the Public Counsel ("OPC"), the Missouri Industrial Energy Consumers ("MIEC"), and the Midwest Energy Consumers Group ("MECG");

2) The primary differences in the Class Cost of Service Studies ("CCOSS") presented by the Company and those presented by Staff, OPC, and MIEC. The fact I am not addressing all the differences between Ameren Missouri's CCOSS and those performed by the other parties should not be construed as an endorsement of the allocation methods employed by those parties; rather, the differences I don't specifically address do not drive materially different CCOSS results between the Company and the other parties;
3) MECG's rate design proposal for Large General Service ("LGS") and Small Primary Service ("SPS") customer classes;
4) The Economic Development/Infrastructure Efficiency proposals of MIEC and Staff;
5) The positions of Staff, OPC, the Missouri Division of Energy, and the Natural Resources Defense Council ("NRDC") concerning Residential Electric Vehicle Rates;
6) The testimony of Sierra Club, Renew Missouri and Staff on residential Time-Of-Day rates;
7) The Company's efforts towards energy efficiency financing;
8) LED Street Lighting;
9) Staff's recommendation to modify the definition of metered kilowatt-hours ("kWh") for purposes of the Large Transmission Service ("LTS") Rider FAC charge;
10) Staff's recommendation regarding an opt-out option for remote meter reading; and

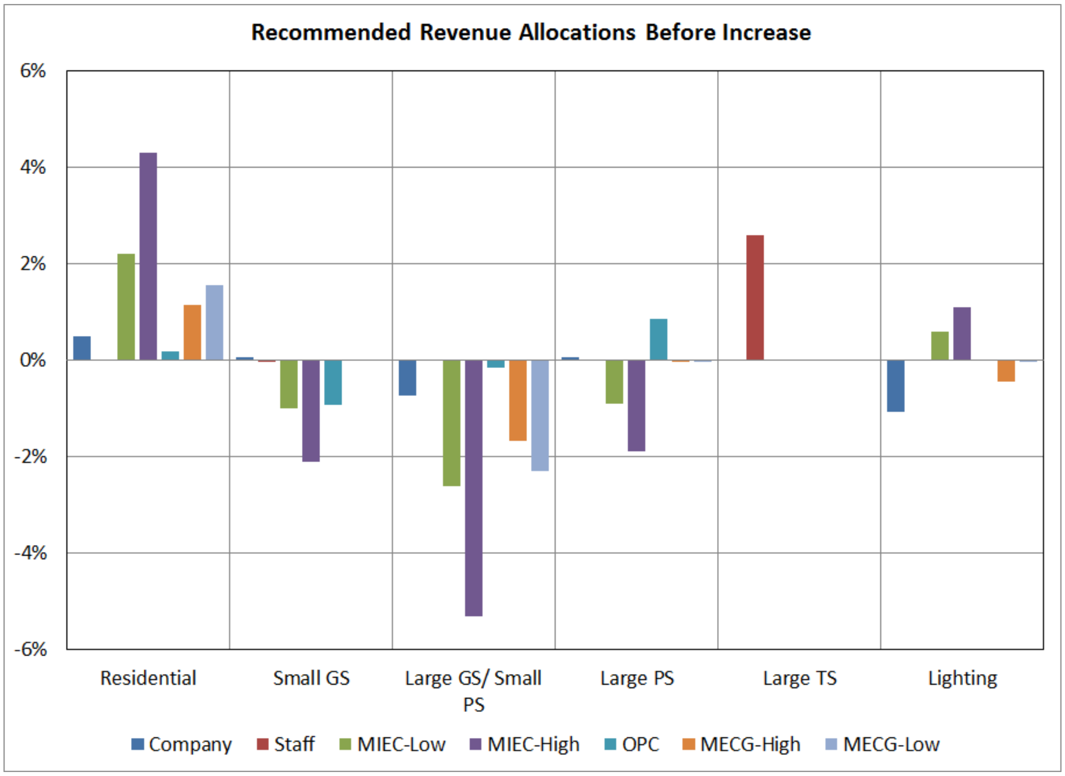
11) Staff's suggestion to study the movement toward Seasonal and Shoulder rates.

## III. RATE INCREASE ALLOCATION

**Q. Please summarize the proposed rate increase allocations presented.**

A. Figure 1 below depicts the various proposals in this case.

**Figure 1 – Comparison of Recommended Revenue Neutral Shifts**




Ameren Missouri's Recommendation:

The Company proposes a six step process similar to what the Commission approved in Ameren Missouri's last rate case, which includes revenue-neutral shifts consistent with past Commission orders and approved stipulations.

Staff's Recommendation:

1. Staff recommends a revenue-neutral shift in revenue responsibility from the Small General Service ("SGS") class to the LTS class. 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.

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 each class's percentage of the program, as provided by Ameren Missouri.

3. Staff proposes to determine the amount of revenue increase to be assigned as described in Step 2, by subtracting the total Step 2 amount 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 described in Step 1.

<u>OPC's Recommendation</u>:

OPC recommends an adjustment to eliminate 20% of the variation from cost for the General Service and Small Primary Service ("SPS") classes. OPC further recommends: the SGS class receive a 0.92% downward adjustment; the LGS and SPS classes receive a 0.15% downward adjustment; the Residential class receive an upward adjustment of 0.18%; and the LPS class receive and upward adjustment of 0.86%. After application of these adjustments, OPC recommends an equal percentage increase in the base rate revenue of all classes.

<u>MIEC's Recommendation</u>:

MIEC recommends a revenue-neutral revenue allocation adjustment within 25%-50% of class-cost-of-service results before any increase. A 25% adjustment should be the minimum movement, but if the rate increase awarded to the Company is substantially less than it requested, the adjustment should be closer to 50%. After those interclass adjustments, any overall increase should be applied to classes as an equal percent basis. Table 1 below depicts MIEC's interclass revenue-neutral adjustments before any overall increase at 25% and 50% movement.[1]

**Table 1 – Interclass Revenue-Neutral Adjustments before Increase**

| | At 25% | At 50% |
|---|---|---|
| Residential | 2.20% | 4.30% |
| Small GS | -1.00% | -2.10% |
| Large GS/ Small PS | -2.60% | -5.30% |
| Large PS | -0.90% | -1.90% |
| Large TS | 0.00% | 0.00% |
| Lighting | 0.60% | 1.10% |

MECG's Recommendation:

The MECG does not oppose the Company's proposed class revenue allocations if the Commission were to award the Company its proposed $206 million revenue requirement increase. If the Commission were to award a revenue requirement increase lower than that proposed by the Company, the Commission should allocate the revenue increase using the following steps:

a) Start with the revenue allocation proposed by the Company at the Company's proposed revenue requirement;

b) Apply one-half of the reduction from the Company's proposed revenue requirement to the approved revenue requirement to the LGS and SPS classes on a current base retail revenues basis;

[1] Brubaker Schedule MEB-COS-6, p. 1 - 2 of 2.

c) Set the increase for the SGS and LPS classes at the system average increase; and

d) Apply the remaining reduction from the Company's proposed revenue requirement to all other classes on an equal percentage basis.

**Q. Do you observe any trends in the rate increase allocation proposals submitted?**

A. Yes. All of the parties except Staff propose a positive revenue-neutral shift for Residential customers. Many of the parties have proposed a negative revenue-neutral shift for the SGS class. All parties except Staff are proposing a negative revenue-neutral shift for the LGS and SPS classes. Overall, the proposed recommended revenue-neutral shifts vary widely, due largely to the proposals from MIEC and MECG. The proposals from MIEC and MECG vary widely for two primary reasons: 1) the proposals are more aggressive steps towards rates that reflect cost of service; and 2) the proposals become more aggressive if the approved rate increase is less than the requested rate increase.

**Q. What is the Company's recommendation after reviewing the positions submitted by others?**

A. I recommend the Commission approve the Company's proposed six-step process. The Company's proposal is consistent with prior Commission orders and Commission-approved stipulations.

**Q. Is it reasonable for the Commission to take bigger steps towards rates that reflect the cost of service study results, as compared to the Company's proposal?**

A. The Commission could choose to take bigger steps towards cost of service-based rates; however, I recommend the Commission do so only after approving specific cost of service methodologies. In this case, there are key differences among the cost of service studies submitted that will drive the ultimate cost of service targets. My recommendation is consistent with my belief the Commission should approve: 1) the use of the 4-Noncoicident Peak – Average and Excess approach for allocating production plant; and 2) the inclusion of a minimum distribution system analysis that classifies and allocates customer-related portions of the distribution system on a per-customer basis.

**Q. Do you have any other recommendations for rate increase allocations?**

A. Yes. No party other than Ameren Missouri filed a CCOSS that separately identified costs of the Company-owned lighting class and the customer-owned lighting class. I recommend the Commission approve the Company's proposed revenue shifts to better align rates between the two lighting service offerings.

## IV. CLASS COST OF SERVICE

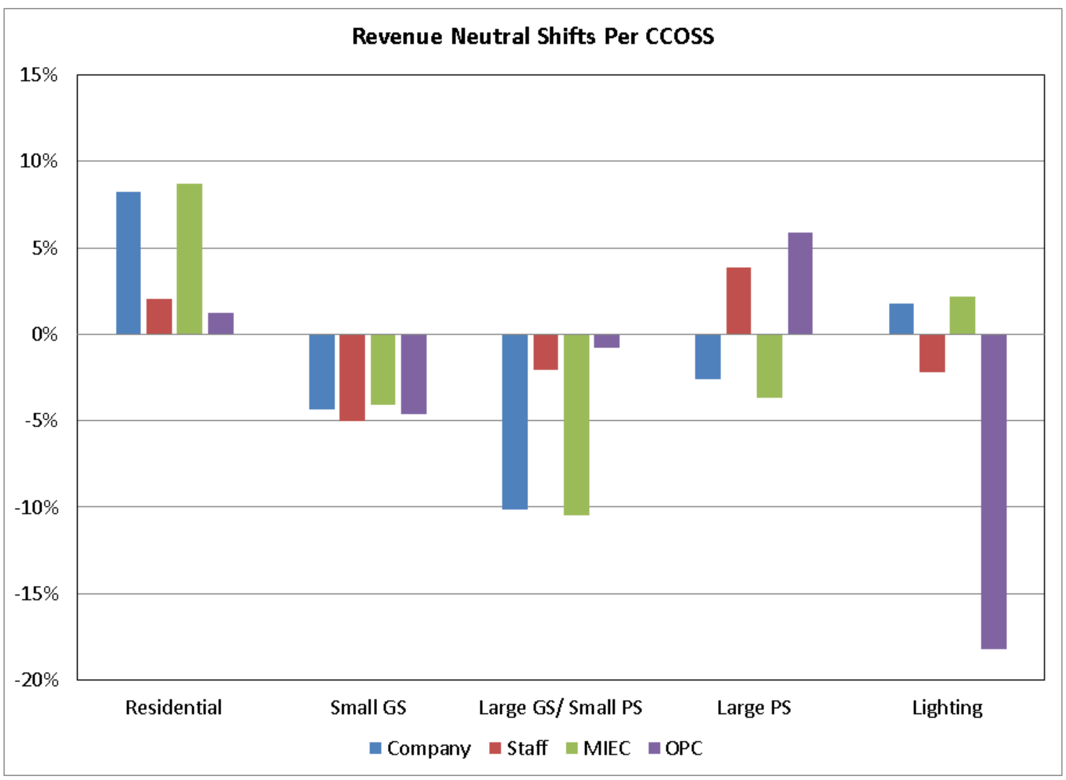
**Q. Which parties filed a CCOSS with direct testimony?**

A. The Company, Staff, OPC, and MIEC filed CCOSS.

**Q. Please provide a comparison of the cost of service models of the various parties.**

A. Comparing the required revenue-neutral shifts between classes results in each class achieving its cost of service target, and provides a consistent metric to compare the cost of service studies. Figure 2 below compares the revenue neutral shifts for the studies submitted in this case.[2] All studies support a revenue neutral shift for the Residential class, but there is significant variability in the results of each study. There is also directional consistency in the results for the SGS, LGS, and SPS classes, but significant variability in results for the LGS and SPS classes. The biggest outlier is OPC's model for the Lighting class. In addition, OPC's and Staff's models each show divergent views of the LPS and Lighting classes compared to the Company's and MIEC's CCOSS.

**Figure 2 – Comparison of Revenue Neutral Shifts**




**Q. Have you been able to identify the primary drivers behind the differences in the CCOSS results between the parties?**

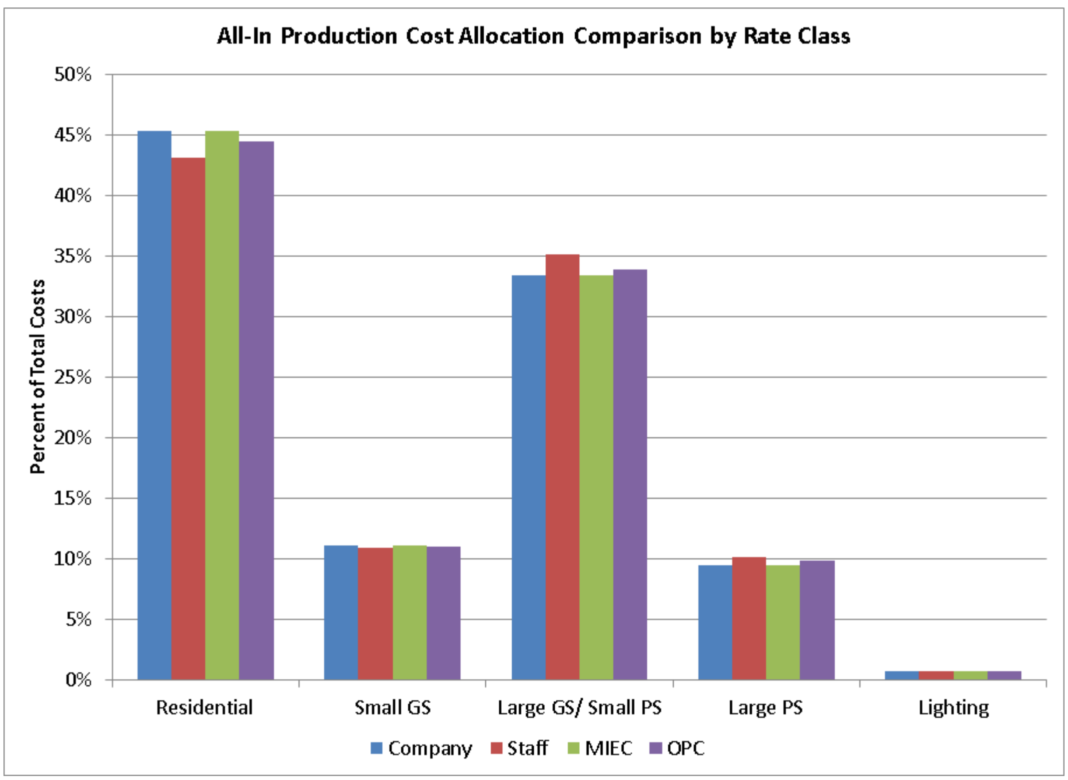
[2] The Staff revenue neutral shifts in the chart include a correction to Staff's model for the allocation of meter reading expenses. The Company is unable to run Staff's CCOSS but was able to estimate the impact of the correction.

A. Yes. The primary differences can be summarized into three categories: 1) the Production Cost Allocator; 2) the inclusion of a minimum distribution system analysis (and to a lesser extent, the type of minimum distribution system analysis); and 3) the total operating revenues.

**Q. Please provide a more detailed description and of the primary drivers causing differences in the CCOSS results.**

A. Figure 3 below shows the allocation of All-In Production Costs, which includes both energy and demand-related production costs.

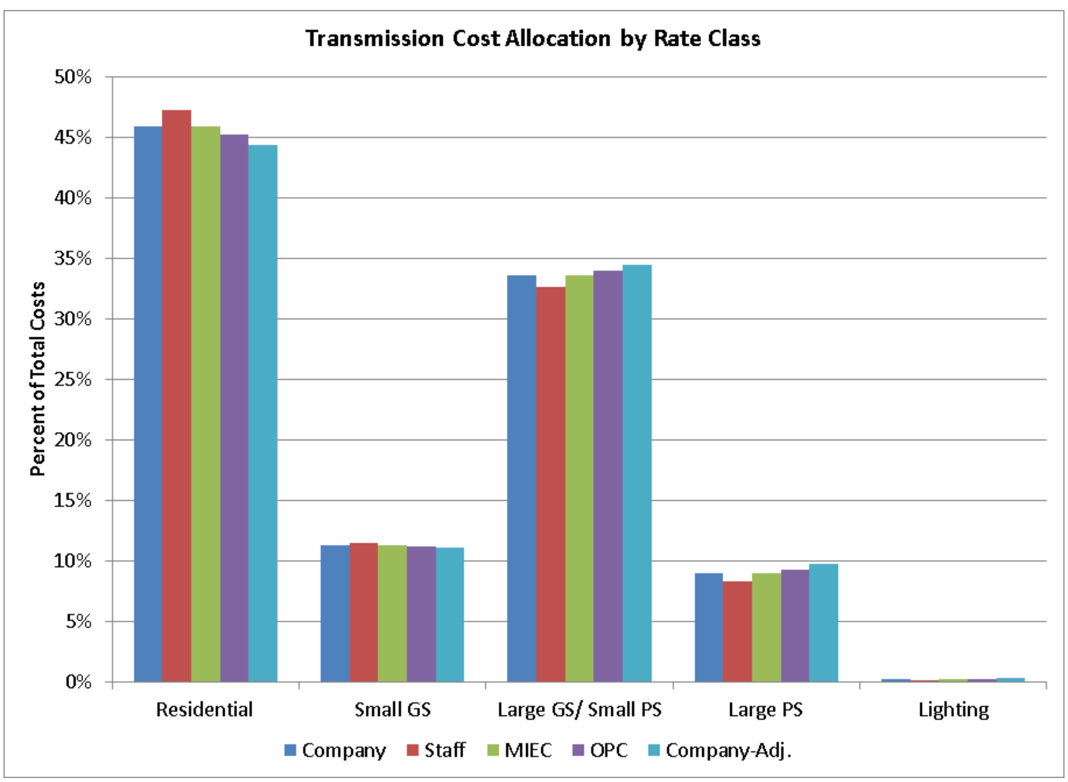
**Figure 3 – Comparison of All-In Production Cost Allocations**




Based on Figure 3, it is clear Staff's analysis is an outlier when compared to the other studies. I must point out that, while the differences may look small, applying even small percentage differences to the Company's production cost of service – which totals about $1.9 billion and represents 2/3rds of the total cost of service – result in significant dollar differences. Figure 3 shows that the Company's and MIEC's cost allocations are very close, and that the allocations between the Company and OPC are less than 1% for the Residential class. Yet, Staff's allocation to the Residential class is 2.23% less than the Company's, resulting in a more than $40 million difference in the Company's cost of service for the that rate class. Later in my testimony I discuss an error in Staff's production plant allocation that, once corrected, would more closely align results with the Company's allocation of production plant.

I also have included Figure 4 below, showing the allocation of Transmission Costs. It is noteworthy that the Company, Staff, and MIEC all used a 12-coincident peak allocation methodology. In contrast, the OPC study, which proposed a 90% weight on the 12-coincident peak and 10% on energy, shows as slightly lower allocations to the Residential class.

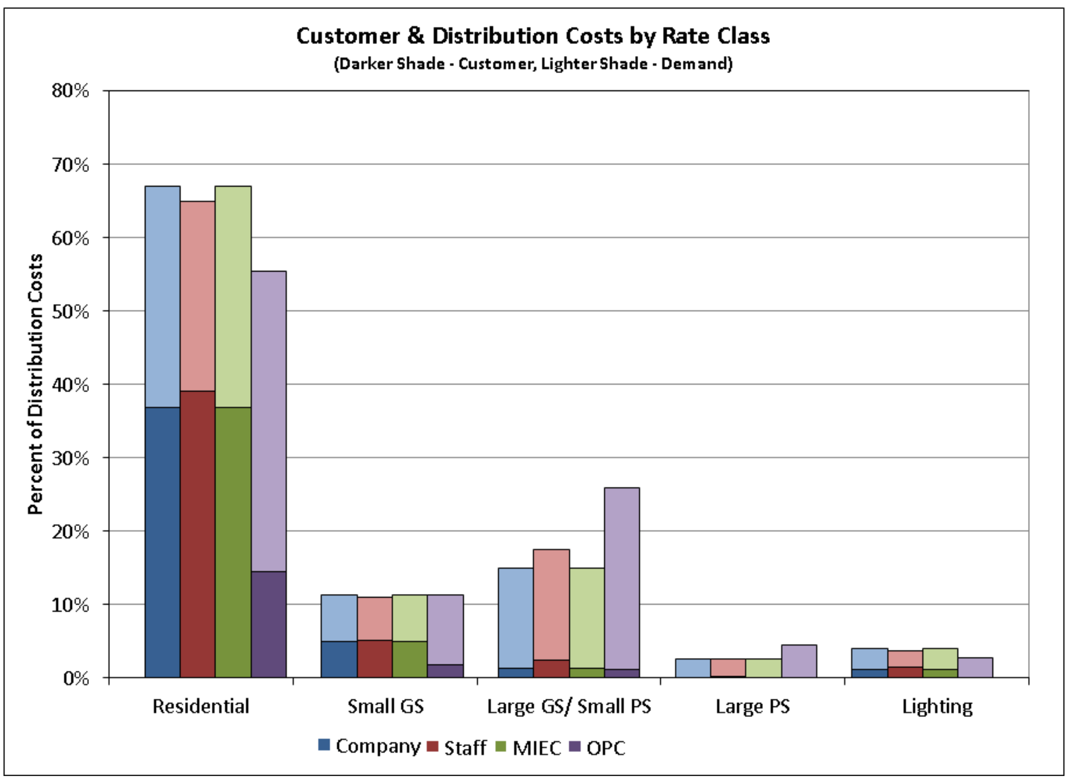
**Figure 4 – Comparison of Transmission Cost Allocations**



Also, as discussed later in my testimony, the Company ran an adjusted transmission allocator to incorporate a stronger energy weight than OPC proposed, which results in an even lower weighting towards Residential. While there is a difference in transmission cost allocations, only about 6% of the total cost of service is transmission-related; meaning an allocation difference of 1% would create approximately a $2 million difference in the cost of service results.

I have also included Figure 5 below, showing the allocation of Customer and Distribution Costs.

**Figure 5 – Comparison of Customer and Distribution Cost Allocations**

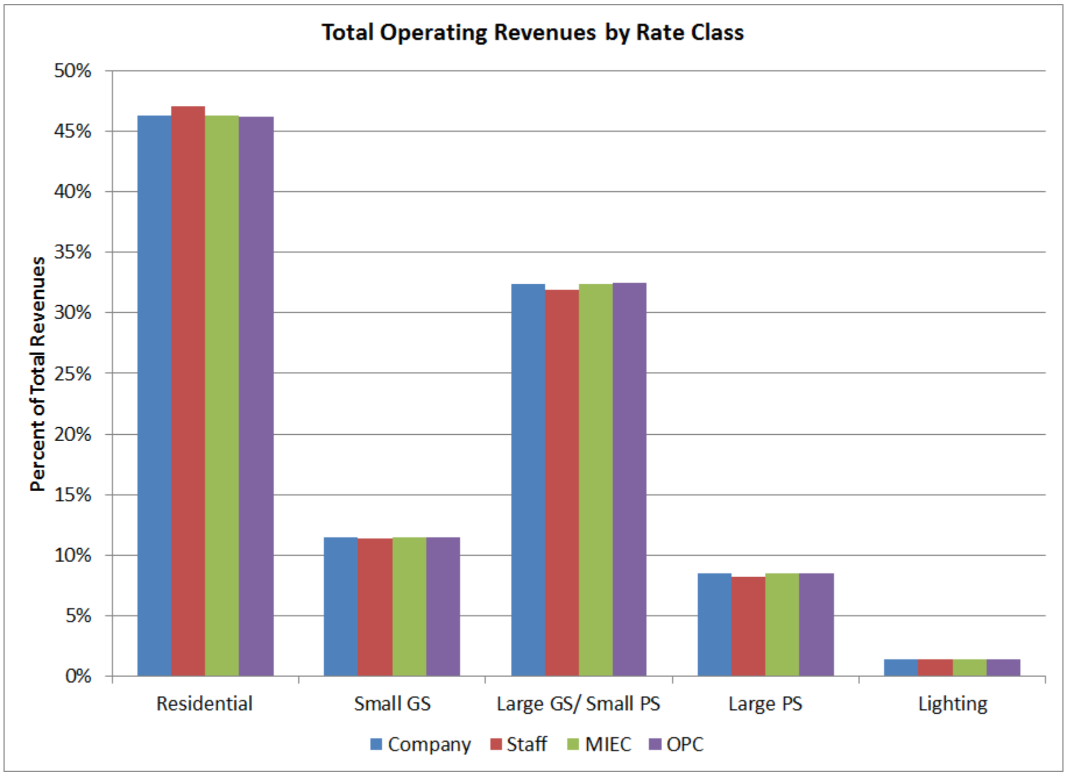



Because there is a significant difference in how the parties classified Customer Costs, the chart shows them as totals; the darker shade in the bars represents the customer-related costs while the lighter shade represents the demand-related costs.[3] The chart shows the OPC's analysis in this area is a significant outlier. It is obvious that the OPC has allocated a much smaller portion of the Company's distribution system costs to the Residential class. The chart also demonstrates that the primary driver for the OPC's under-allocation of Distribution Costs to the Residential class is the OPC's understatement of customer-related costs (the darker shade of OPC's bar in the graph below is significantly smaller compared to the other studies), which is driven by the OPC's status as the only party in the case not to include an assessment of minimum distribution system costs in its CCOSS. I discuss the need to include an assessment of the minimum distribution system costs later in my testimony. About 27% of the total cost of service is associated with Customer and Distribution-related Costs, so a 1% difference in allocation would result in a $7.7 million difference in cost of service. In this case, the OPC's allocation to the Residential class is about 11.6% lower than the Company's, which produces a nearly $90 million difference in the Company's cost of service.

Finally, I have provided Figure 6, which shows the Total Operating Revenues compared to the total.

[3] The Customer-related portion in the chart includes the amounts of Distribution-related costs that Staff classified as Customer-related and allocated based on the number of customers.

**Figure 6 – Comparison of Total Operating Revenues**




The significance of looking at revenues is that if one CCOSS showed a rate class having higher revenues than another, then even if the class cost of service were equal the higher revenue study would show the required revenue increase for that class to be lower. Notice that Staff's analysis includes a higher percentage of revenues in the Residential class and lower relative revenues in the LGS/SPS classes as compared to the other studies. This difference in revenues partially explains why Staff's study is not showing as much of a revenue shortfall as the Company's or MIEC's CCOSS. Total operating revenues from the Residential class are about $1.56 billion, so the 0.8% difference between the Company's and Staff's studies produces a revenue shortfall difference of about $12.5 million.

**a. <u>Production Cost Allocator</u>**

**Q. You mentioned above that Production Cost Allocation is a significant driver of differences in the presented CCOSS. Please summarize the positions of the parties in this case regarding the Production Plant Allocator.**

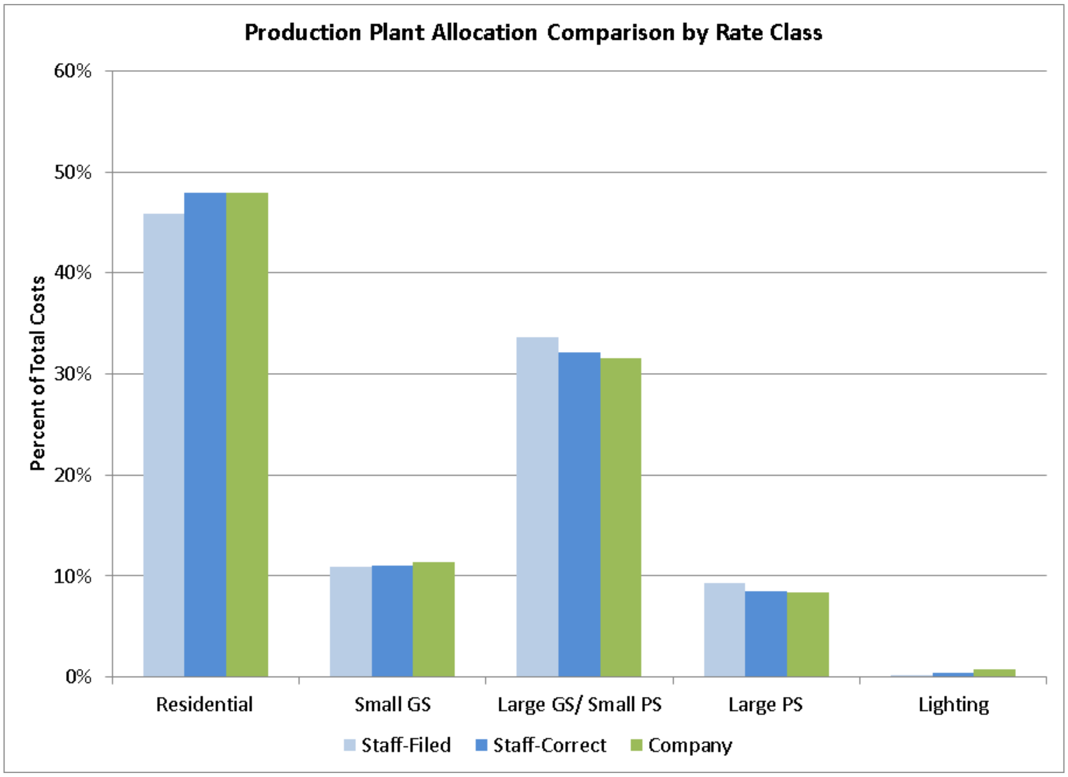
A. For Production Plant, the Company used a 4 non-coincident peak – average and excess ("4-NCP A&E") approach, which was also used by MIEC and recommended by MECG. Staff utilized a process it calls the detailed Base Intermediate Peak ("BIP") method, and the OPC used an 80/20 weighting of 12 coincident peaks and energy.

**Q. Do you have concerns about the Production Plant Allocator Staff developed using the detailed BIP method?**

A. Yes. At this point, my primary concern is a modeling error in the Production Plant Allocator developed by Staff. Because production plant costs make up a significant portion of Ameren Missouri's overall cost of service, a mistake on this allocator will have significant impacts on the overall results of a CCOSS.

Staff's Production Plant Allocator is both cost-weighted and load-weighted. First Staff's model develops a load weighting between base demand (average demand, which is mathematically the same as using an energy allocator), incremental intermediate demand (demand in excess of base using 12-CP), and incremental peak demand (demand in excess of intermediate using 3-CP). To apply the cost weighting, each of those demands is then multiplied by the per-book $/kW for each of the resource types (i.e. base, intermediate, peak). When applying the cost weighting, Staff should have multiplied the incremental intermediate demands by the $/kW of the intermediate resources, and the incremental peak demand by the $/kW of the peak resources. Instead, Staff made a critical calculation error. When applying the intermediate cost weight, the intermediate resource cost ($/kW) was multiplied by the sum of incremental intermediate demand and base demand, which effectively double-counts base demand. In addition, when applying the peak cost weight, the peak resource cost ($/kW) was multiplied by the sum of incremental peak demand, incremental intermediate demand, and base demand, which effectively triple-counts base demand and double-counts intermediate demands. The fact the calculation of the Production Plant Allocator in this rate case is not consistent with how Staff performed it in the Company's last rate case, and the fact Staff's BIP Fuel In Storage Allocator in this case was performed using only incremental demands (instead of double and triple counting), leads me to believe the issue with Staff's Production Plant Allocator is attributable to an inadvertent modeling error. Figure 7 below compares Staff's filed Production Plant Allocator, a corrected version of that same allocator, and the Company's Production Plant Allocator (based on the 4-NCP A&E method).

**Figure 7 – Comparison of Company and Staff Production Plant Allocators**




It is clear that Staff's filed CCOSS significantly understated the Residential class's cost responsibility and overstated the cost responsibility of the LGS and SPS classes. It is also evident that, with the required correction, Staff's and the Company's CCOSS are significantly more aligned with regard to production plant cost allocation.

**Q. Do you have concerns about the OPC's proposed Production Plant Allocator?**

A. Yes. The OPC is proposing that an 80% weight be applied to the 4 non-coincident peak method, with a 20% weight applied to energy. But this proposed 80/20 split is totally arbitrary. Qualitatively, the OPC's all-in allocation of Production Costs is reasonably similar to the Company's. As shown earlier in my testimony, the primary difference between the Company's and the OPC's CCOSSs is the allocation of

Distribution and Customer Costs (specifically whether a minimum distribution analysis should be included).

**b. <u>Transmission Cost Allocator</u>**

**Q. What are the positions regarding the allocation of Transmission Costs?**

A. The Company, MEIC, and Staff allocated Transmission Costs using the 12 coincident peak methodology. In contrast, the OPC used a weighted average, with 90% of the weight applied to the 12 coincident peak method and 10% of the weight applied to energy.

**Q. Did the OPC provide any support for its proposed 90/10 weighted average to allocate Transmission Costs?**

A. No, the OPC did not provide any quantitative support for its proposal; instead, the OPC provided only a vague qualitative discussion about how transmission planning has evolved to accomplish goals beyond transmission reliability.

**Q. Do you agree with the OPC's proposal to use a 90/10 weighted average to allocate Transmission Costs?**

A. No, I do not agree with the 90/10 weighted average, but the OPC was indirectly correct in recognizing that a portion of transmission expenses are allocated to the Company on an energy basis. Specifically, the Midcontinent Independent System Operator, Inc. ("MISO") Schedule 26A charges, which are related to the large regional Multi-Value Projects, are allocated on an energy basis. Therefore, it is reasonable to allocate those specific costs in the class cost of service on an energy basis.

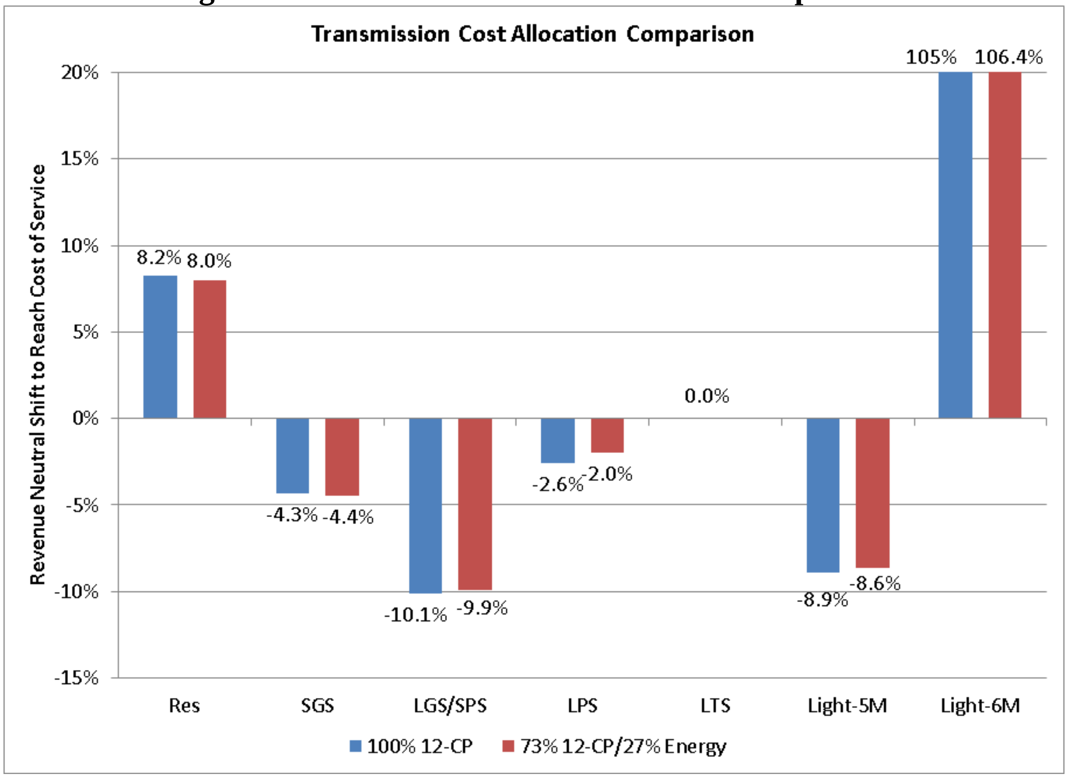
**Q. If the MISO Schedule 26A costs are allocated on an energy basis, what is the implied weighted average between the 12 coincident peak method and energy?**

A. The implied weighting would be about 73% weighted towards the 12 coincident peak method and 27% weighted towards energy. This highlights the importance of seeking a quantitative approach to allocating costs. Instead, the OPC chose a seemingly random 90/10 weighting scheme, while a more detailed analysis supports the 73/27 weighting scheme I just mentioned.

**Q. Would updating the Transmission Cost allocations change the Company's rate increase allocation recommendations between rate classes?**

A. No. The chart below shows the revenue neutral shifts required to reach each class's cost of service based on the two different Transmission Cost allocation methodologies (100% 12-CP vs. 73% 12-CP/27% Energy).

**Figure 8 – Transmission Cost Allocation Comparison**




While the overall revenue neutral shifts have changed for each class, the Company's proposal for modest shifts remains unaltered. In fact, the chart demonstrates the Company's proposed revenue neutral shifts are still well below the revenue neutral shifts required to move each class to its cost of service.

### c. Minimum Distribution System

**Q. Did any other parties who filed a CCOSS include an assessment of Minimum Distribution System costs?**

A. Yes. MIEC used the same minimum distribution system analysis that the Company used. Staff used the results of a zero-intercept study to represent minimum distribution system costs, which is the same study the Company used in its previous rate cases. The OPC was the only party in the case who filed a CCOSS and who did not include an assessment of minimum distribution system costs.

**Q. Does the OPC explain why it did not incorporate a minimum distribution study into its CCOSS?**

A. The rationale that the OPC offered is that only the costs of facilities not providing electrical service should be allocated and collected on a customer basis.

**Q. Do you agree with the OPC's position?**

A. No. First, I will note that the Company's minimum distribution analysis identified components of the distribution system that do not "provide electrical service," like lighting arrestors, switches, fencing, etc., but still represent basic infrastructure required for safe and adequate service. Second, because of safety and operational issues, a minimum size of facilities is needed to make electrical service available (e.g. pole height, conductor size, etc.), and those costs are incurred irrespective of customer demand. Lastly, a minimum distribution study also recognizes there are certain distribution facility costs that vary directly with the number of customers being served as opposed to the amount of load being served, which is why the Company, MIEC, and Staff classify and allocate those costs on the basis of customer counts. Ameren Missouri witness Steven Wills provides additional testimony and insights on this topic.

**Q. If Staff's CCOSS includes a minimum distribution system analysis, why has Staff not included an Energy Grid Access Charge in its rate design proposal?**

A. I do not know. Staff, like the Company and MIEC, used the customer count to allocate the customer-related portion of Distribution Costs to the various rate classes. Staff also uses the customer count allocator the same way as Ameren Missouri did. But when it bundles costs and determines the appropriate monthly fixed charges, Staff treats those Distribution Costs as demand-related instead of customer-related. In short, although Staff recognizes that those Distribution Costs *vary directly with the number of customers*, Staff inexplicably allocates those costs as if they were demand-related. It stands to reason that if a portion of Distribution Costs vary with the number of customers, then those costs should be collected as a per-customer charge. Mr. Wills provides additional testimony and insights on this topic.

**Q. What monthly Energy Grid Access Charge would Staff's CCOSS support if the portion of the distribution system were properly treated as customer-related?**

A. Staff's study would support an Energy Grid Access Charge of nearly $13. This highlights the reasonableness of the Company's request of a monthly $4.89 Energy Grid Access Charge.

## V. LARGE GENERAL AND SMALL PRIMARY SERVICE RATES

**Q. Please summarize the direct testimony positions of other parties to this case related to the rate design for LGS and SPS rates.**

A. MECG was the only party who filed testimony asking for a rate increase to be applied in a manner other than an equal percentage across all rates within the LGS and SPS rate classes (after applying any revenue neutral shifts and keeping certain rate uniformity across classes). Specifically, MECG is asking for disproportionate increases to demand charges for both those classes. Finally, I will note that MECG is not proposing to eliminate the hours use rate design, so I will focus my rebuttal on MECG's proposal to increase demand charges.

**Q. What would the increase to the LGS and SPS demand charges be if MECG's proposal were approved by the Commission?**

A. It is very difficult to provide specific examples for MECG's proposal, because the rates that result from that proposal are dependent on the interactive effects of the approved revenue neutral shifts and the total amount of the rate increase approved in this case. However, to keep it simple, let's assume the Company is awarded 100% of its requested revenue increase. In such an example, MECG agrees with the Company's proposed revenue neutral shifts. However, after those revenue neutral shifts are made, MECG is asking for nearly all of the increase for the LGS and SPS rate classes to be applied to the demand charges for those classes. Table 2 below summarizes the impact.

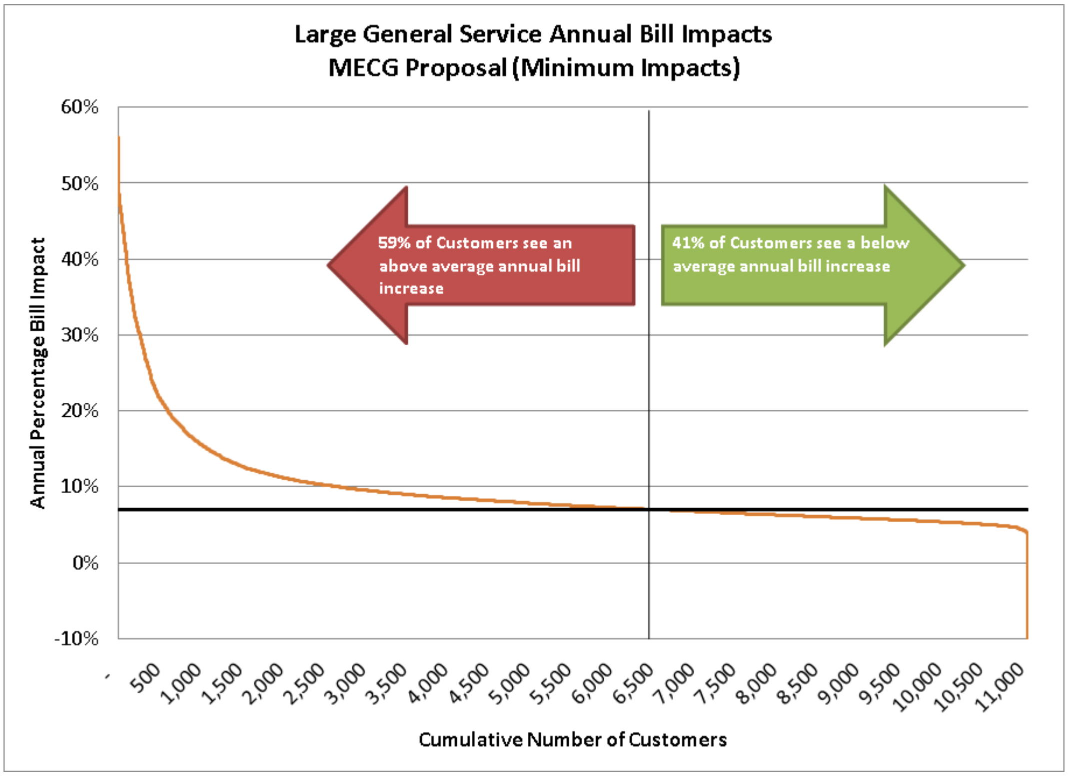
**Table 2 – Calculation of Demand Charge Increase with MECG's Proposal**

| | LGS | SPS | Total |
|---|---|---|---|
| Current Demand Charge Revenues ($) | $69,454,443 | $19,488,486 | $88,942,929 |
| Billing Demands (kW) | 24,316,339 | 8,248,798 | 32,565,137 |
| Realized Annual Demand Charge ($/kW) | $2.86 | $2.36 | $2.73 |
| | | | |
| Proposed Increase ($) | $42,277,294 | $16,740,838 | $59,018,132 |
| MECG Demand Charge Revenues ($) | $111,181,171 | $36,417,843 | $147,599,014 |
| Billing Demands (kW) | 24,316,339 | 8,248,798 | 32,565,137 |
| MECG Annual Demand Charge ($/kW) | $4.57 | $4.41 | $4.53 |
| MECG % Increase in Demand Charge | 60% | 87% | 66% |

**Q. Did MECG provide a bill impact analysis of its proposed rate design change?**

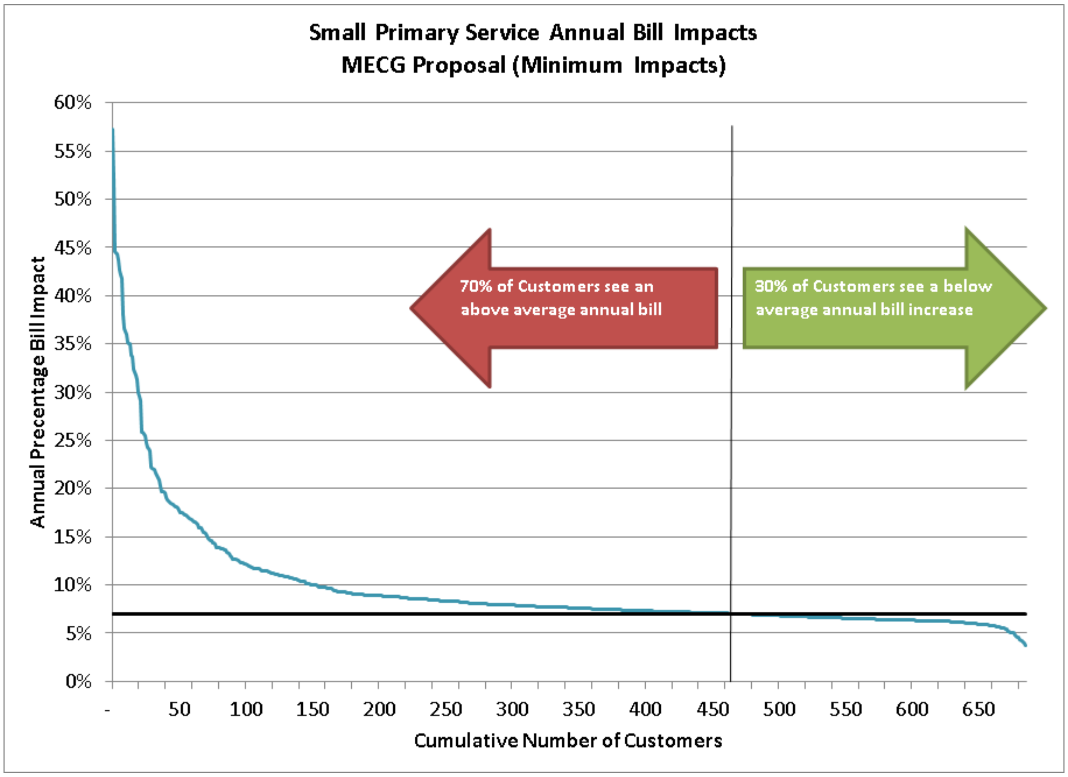
A. No. However, I have conducted such an analysis to provide the Commission with the information necessary to make a decision regarding MECG's proposal. Figure 9 and Figure 10 below represent the bill impacts implied by MECG's proposal.[4]

**Figure 9 – Large General Service Bill Impacts of MECG's Proposal**




[4] Excludes the effects of seasonal energy charges, reactive charges, time-of-day, or Rider B charges.

**Figure 10 – Small Primary Service Bill Impacts of MECG Proposal**




It is plain to see that MECG's proposal will create significant differences in bill impacts, which would be very large in some cases. Each chart includes a black horizontal line that indicates the average class increase, and under the Company's proposal to change all of the rate elements by that average percentage the average bill impacts to all customers will also equal that average percent increase.

**Q. Do you agree with MECG's proposed rate design for the LGS and SPS rate classes?**

A. Not entirely. Based on its proposal, it seems MECG is moving away from the hours use rate design. The hours use rate design was originally designed to recover demand-related Distribution Costs in the demand charge, with remaining costs being collected through the hours use charges. Unless the Commission decides to move away from the hours use rate design (which no party has recommended in this case), I recommend the Commission limit any demand charge increase to a level where the percentage of revenues from the demand charge are equal to the percentage of costs that are demand-related Distribution Costs.

**Q. Have you prepared a hypothetical case to demonstrate the approach?**

A. Yes. Table 3 below summarizes the hypothetical case. The CCOSS has both LGS and SPS summarized as a single rate class; therefore the CCOSS only provides the percentage of distribution demand-related costs for the total of the two classes. All else being equal, and as reflected in current rates, the SPS demand charge would be lower than the LGS demand charge because there are less distribution system costs associated with serving primary service customers. With that as a constraint, I was able to solve for annual demand charges that would result in 12.9% of total revenues between the LGS and SPS rate classes coming from demand charges (the same percentage that the CCOSS implies are demand-related distribution costs). The hypothetical alternative shown in Table 3 also ensures the hours use rate elements for the SPS class will not increase beyond those in the LGS rate class, thereby preserving the current rate design relationships between the two classes.

In short, Table 3 shows that if 47% of the proposed increase were applied to the demand charges for both LGS and SPS, then the percentage of revenues from demand charges would be the same as the percentage of demand-related distribution costs from the CCOSS (for the aggregate of LGS and SPS).

**Table 3 – Calculation of Hypothetical Demand Charges**

| | LGS | SPS | Total |
|---|---|---|---|
| Current Revenues ($) | $603,408,285 | $239,989,465 | $843,397,750 |
| Current Demand Charge Revenues ($) | $69,454,443 | $19,488,486 | $88,942,929 |
| Billing Demands (kW) | 24,316,339 | 8,248,798 | 32,565,137 |
| Realized Annual Demand Charge ($/kW) | $2.86 | $2.36 | $2.73 |
| Realized % of Rev. from Demand Charges | 11.5% | 8.1% | 10.5% |
| CCOSS Target Rev. From Demand Charges | 13.8% | 10.7% | 12.9% |
| Proposed Revenues ($) | $645,654,224 | $256,723,972 | $902,378,196 |
| CCOSS Rev. from Demand Charges ($) | $89,240,965 | $27,366,873 | $116,607,838 |
| Increase in Demand Charge Rev. ($) | $19,786,521 | $7,878,387 | $27,664,909 |
| Billing Demands (kW) | 24,316,339 | 8,248,798 | 32,565,137 |
| CCOSS Demand Charge ($/kW) | $3.67 | $3.32 | $3.58 |
| CCOSS % Increase in Demand Charge | 28% | 40% | 31% |
| CCOSS % of Increase for Demand Charges | 47% | 47% | 47% |

**Q. Do you have any additional comments about MECG's proposal?**

A. Yes. The example above is based on an assumption the Company's full rate increase request is approved. Therefore, the bill impacts presented in Figures 9 and 10 for MECG's proposal represent the minimum bill impacts because MECG is proposing more costs be moved to the demand charge as the absolute level of increase declines compared to the Company's original request.

## VI. ECONOMIC DEVELOPMENT/INFRASTRUCTURE EFFICIENCY

**Q. Please summarize the economic development/infrastructure efficiency proposals filed by the other parties.**

A. The MIEC filed an economic development tariff modeled closely after Kansas City Power & Light Company's ("KCP&L") current economic development rider. Staff recommends Residential customers in targeted areas (which would be similar or identical to those identified in Ameren Missouri's proposed Economic Redevelopment and Efficient Infrastructure Utilization Pilot) receive a monthly discount of approximately 2%, SGS customers receive a monthly discount of approximately 2%, and all other customer classes (LGS, SPS, and LPS) receive a monthly discount of approximately 0.5%.

**Q. Do you have any concerns about MIEC's proposed economic development rider?**

A. Yes. Based on the advice of counsel, the Company has significant concerns about the legality of providing a discounted rate for purposes other than a difference in character of service. Therefore, the Company's proposed Economic Redevelopment and Efficient Infrastructure Utilization Pilot is a superior option, because the discount (if any) would be specifically linked to the circumstances of the local infrastructure, which mitigates rate discrimination concerns.

**Q. Does the Company support Staff's proposed infrastructure discount?**

A. Not at this time, because there is still a great deal of important information missing regarding Staff's proposal.[5] For instance, no information was presented with regard to the numbers of customers to which Staff's proposed discount would apply. If

[5] I note that there are errors in the charts presented in Staff's analysis. On p. 15 - 16 in Staff's Report on Additional Issues, the data labeled as "Ameren 2014" in the charts is the same as the data labeled as "Empire" thus the data in the charts labeled as "Ameren 2014" is incorrect. Also, the chart on p. 15 the "Distribution % of Total Cost of Service" is incorrectly shown on the chart as zero when in fact it should be shown as a little over 1%.

implemented in this rate case, base revenues would need to be adjusted to account for reduced revenues associated with the proposed discount going forward. In addition, there is no discussion in Staff's proposal of how movement within the service territory would be treated. For example, if a customer moved from one spot within Ameren Missouri's service territory to an area with a discount, the infrastructure that customer previously used would now be underutilized.

**Q. Do you believe a 2% discount for Residential and SGS and a 0.5% discount for LGS customers would drive a material increase in utilization of facilities?**

A. It seems unlikely that a discount of that magnitude will make a material difference in a customer's decision as to where to locate. I would expect Residential customers to ascribe higher value to things like quality of nearby schools, safety, location of friends and family, etc. I would also expect a larger discount would be needed to sway small and large business customers to move to areas where facilities are underutilized. For instance, the Company's current Economic Development Rider offers a 15% discount and MIEC is proposing even larger discounts would be required to alter customer behavior.

**Q. Staff has recommended that Ameren Missouri modify its facility extension provisions to more discreetly consider the incremental cost a customer causes to the system in determination of how much, if any, of an advance the customer should be required to pay. Please respond.**

A. As stated in the Company's response to Staff's report in File No. EW-2016-0041, to the extent the Commission is interested, the Company is willing to explore revised line extension policies that resemble those included in Kansas City Power & Light—Greater Missouri Operations' ("KCP&L-GMO") tariffs. However, the Company also stated its line extension policies have been in effect for decades, and any changes to those policies need to be carefully reviewed prior to implementation to ensure customers and communities in our service territory are not adversely affected. With that in mind, if the Commission sees potential value in revisions to the Company's line extension policies, Ameren Missouri is willing to conduct a twelve-month historical study comparing the revenue requirement impact of its existing line extension policy to a line extension policy modeled after that in effect for KCP&L-GMO. Such a study could be completed by June 2018, and would include the Company's recommendation about whether its line extension policies should be changed. That recommendation would be based on the revenue requirement analysis as well as an assessment of other factors like customer understanding and expected impact on efficient utilization of existing facilities.

## VII. RESIDENTIAL ELECTRIC VEHICLE RATES

**Q. Please summarize the direct testimony positions of the other parties related to electric vehicle rates.**

A. Staff and the OPC indicated that they are open to a rate option for customers with an electric vehicle. The Division of Energy expressed concerns about the costs of offering an end-use rate option that only applies to electric vehicles. The NRDC presented evidence that time of day rates have an impact on charging behavior, but also noted a whole house time of day rate option could be a barrier to adoption of such rates. The NRDC further noted that advanced metering infrastructure may be a platform to allow a rate option that only applies to the charging of the electric vehicle. No party provided a specific electric vehicle rate proposal.

**Q. Is the Company agreeable to implementing a time of day rate option specifically for customers with electric vehicles?**

A. Electric vehicle owners already can participate in the Company's current residential time of day pilot, which could accomplish the goal of shifting vehicle charging to off-peak periods. However, if the Commission believes a more refined rate option would be valuable, then the Company is willing to test a rate option for electric vehicle owners. The simplest path to test a time of day rate option for electric vehicle owners is to add a super off-peak timeframe to the existing Residential time of day pilot that would only be available to customers with an electric vehicle. I recommend the super off-peak period be defined as 11 p.m. through 7 a.m., which is the same timeframe adopted by Georgia Power. But more importantly, starting the super off-peak period at 11 p.m. aligns with observed lower overall load conditions on the Ameren Missouri system. There are various ways to determine a super off-peak price. Ideally, such a price would cover the variable costs incurred during the super off-peak time period plus provide a contribution to fixed costs. For purposes of an electric vehicle pilot rate, I suggest the super off-peak price initially be set at 3 cents/kWh, which is significantly lower than the current off-peak rate of 7.55cents/kWh.

**Q. What would the primary learning opportunity be for offering a whole house time of day rate option to electric vehicle owners?**

A. The primary learning opportunity is to compare the energy consumption patterns of electric vehicle owners (based on on-peak, off-peak, and super off-peak periods) to the energy consumption habits of other customers in the Company's load research sample. If the Commission felt that hourly data was needed for customers subscribing to the electric vehicle rate option, more expensive metering would need to be installed and additional data collection costs would be incurred. I would note that although hourly metering would be more expensive, it may be advantageous to answer more detailed questions about energy consumption and electricity demand patterns.

**Q. Is there enabling technology for electric vehicle owners to take advantage of a whole house time of day rate option?**

A. Yes. Some car models offer app-based charging programs that can be used to control vehicle charging. In addition, some home chargers include programming options to control vehicle charging. Finally, it is possible for customers to use a typical plug timer to control when their vehicles are charged.

**Q. Are there any disadvantages of implementing a whole house time of day rate option targeted at electric vehicle owners?**

A. Yes. A potentially significant disadvantage of targeting electric vehicle owners with a whole house time of day rate is that the entire load at the house will be subject to time of day rates. The Residential time of day rate option includes an on-peak price over 30 cents/kWh, which could be a significant deterrent to customers who find it undesirable to make other behavioral changes in order to save money on vehicle charging costs. Another disadvantage with a whole home rate option is that energy associated with vehicle charging is lumped with all other energy consumption, which makes it more difficult to precisely analyze consumption habits specifically for electric vehicle charging.

**Q. How might an electric vehicle time of day rate offering evolve over time?**

A. The implementation of smart meters would be a significant technological advance that allows more rate options, flexibility, and insight into electric vehicle consumption habits. For example, linking the home area networking capabilities of smart meters to the electric vehicle, charging station, or potentially other charging-related equipment would open up other valuable pricing options, like demand response options or more advanced time of day options. Also, the ability of the meter to communicate directly with electric vehicle charging equipment would make it possible to offer a rate alternative specifically for the electric vehicle independent of the home's energy consumption.

## VIII. RESIDENTIAL TIME OF DAY RATES

**Q. Did any of the witnesses propose specific changes to Ameren Missouri's current time of day rate designs?**

A. No.

**Q. The Sierra Club and Renew Missouri's witness, Mr. Jester, recommends that the Commission direct Ameren Missouri to market its time of day rate option. Is his recommendation realistic?**

A. No. First, Mr. Jester did not estimate the costs or benefits of such marketing activities. In fact, Mr. Jester recommends the Company calculate customer bills under both the default rate as well as the time of day rate so customers can make an informed decision about which rate is more economical. Unfortunately Mr. Jester fails to identify a path to implement such a plan, and the Company currently does not have the metering capabilities to calculate time of day bills for all 1.2 million of its customers.

**Q. Does the Company's current Residential time of day rate option provide customers with additional information about whether time of day rates are beneficial?**

A. Yes. During the summer season, when the time of day rate is applicable, each customer bill includes a statement of how much the customer saved (or didn't save) by being on the optional time of day rate option.

**Q. What is the Company's position regarding time of day rates?**

A. Expanded adoption, analysis, and discussion of time of day are best suited after or during the deployment of smart meters. The adoption of smart meters will best allow for the types of bill impact analyses desired for decision making. In addition, the adoption of smart meters will allow for ongoing adjustments to a time of day rate design. For example, it is entirely possible that load conditions on the system change with a material adoption of time of day rates, which may necessitate a change in rate design. Without smart meters, each customer's meter would need to be manually reprogrammed, which would be a very time-consuming and costly process.

**Q. Were there any other proposals related to time-varying rates?**

A. Yes. Staff proposed a pilot program to study the effects of a mandatory peak time rebate rate program and its potential ability to defer investments in the distribution system.

**Q. Does the Company agree to conduct such a pilot study?**

A. No, not at this time. There are still significant unspecified parameters of such a study. For example, the Company does not know if a pocket of its distribution system even fits the design criteria for such a study. In addition, the pilot envisions manual billing but without knowing how many customers to which such an effort would apply. Furthermore, no budget or timeframe is specified for the pilot.

## IX. ENERGY EFFICIENCY FINANCING

**Q. Did any party file specific energy efficiency financing proposals for the Company to implement?**

A. No. Staff, the OPC, and the Division of Energy each filed testimony about PACE and PAYS in response to the Commission's order to explore additional issues.

**Q. What efforts is the Company making with regards to financing options for energy efficiency?**

A. First, Ameren Missouri has been and continues to be supportive of PACE financing options for customers. For instance, in 2012, Pat Justis, a manager on my team, was appointed by Mayor Slay to the St. Louis Clean Energy Development Board ("CEDB"), on which he currently serves as its president. The purpose of the CEDB is to execute the powers delegated to it under Missouri's Property Assessment Clean Energy Act in operating the City's PACE program, which was named "Set the PACE St. Louis." To showcase the PACE program, Ameren Missouri has hosted several well-attended events for contractors and customers. In fact, on January 26, 2017, Ameren Missouri is hosting an Energy Efficiency Workshop for the Electrical Board of Missouri and Illinois where Ann Hill (President of RAHILL Capital) will be presenting on PACE financing.

In addition, as some parties mentioned in their direct testimony, through the Company's energy efficiency collaborative, on-bill financing for energy efficiency was evaluated and the Company is actively pursuing implementation of such an option. Several steps still need to be taken before implementation can take place, and the Company remains optimistic that it can soon present the Commission a specific proposal for approval.

## X. OTHER ITEMS

### a. LED Street Lighting

**Q. Please summarize the direct testimony positions of other parties related to LED street lighting.**

A. Only Staff filed direct testimony on the subject of LED street lighting. Staff's testimony summarized the process leading up to the Company's recently approved LED street lighting rate for Company-owned street lights, as well as the revised annual reporting requirements for LED street lighting.

**Q. Was the Company's latest LED report available when the Company filed direct testimony?**

A. No. However, since then the report has been finished, and it is attached to my rebuttal as Schedule WRD-RDR1.

**Q. Does the Company have any recommendations based on its latest LED street lighting analysis?**

A. Yes. The latest economic analysis indicates it is now cost effective to replace directional lights upon failure. Of fixtures not already covered by a street lighting LED conversion program, it is noteworthy that directional lights constitute 20% of the quantity of fixtures but 50% of the energy savings. Following the same approach as the Commission approved in January 2016, I propose new rates for Company-owned LED directional street lights. Attached as Schedule WRD-RDR2 is a red-lined version of the proposed Company-Owned Lighting tariff implementing these new LED offerings. As with the phase-out of horizontal enclosed and open bottom lights, all Company-owned directional street lights will be replaced with LEDs upon failure or with any new installation. The LED conversion will begin July 2017, and will be complete in about five years. In addition, the rates for the new LED directional lights will be about 7.5% lower than the existing high pressure sodium or metal halide lights, which will result in immediate bill savings for customers. With the addition of directional lights, approximately 73% of Company-owned lights are on the path to LED conversion.

**Q. Does the Company plan to keep looking for opportunities to convert even more street lights to LEDs?**

A. Yes. The only remaining style of Company-owned street lights not scheduled for conversion to LEDs is post top lights. Because post-top lights are decorative, the aesthetics of a replacement fixture is critical. Up to this point, conversion of decorative post top lights is still not cost effective, but the Company continues to look for ways to introduce an LED option. Based on continued advances in LED lighting and overall market transformation toward LEDs, I expect a viable option to be available soon.

Furthermore, the Company continues to evaluate the customer-owned street lighting market for LED conversion opportunities. In my direct testimony, I included a proposal that could result in a significant number of customer owned LED conversions. In addition, the Company has explored the potential costs and savings in the Customer-

Owned Street Lighting class as part of its recently completed energy efficiency collaborative process. More opportunities remain for LED street lighting, and the Company continues to seek constructive ways to implement LEDs.

### b. <u>FAC Losses for Large Transmission Service</u>

**Q. Staff recommends modifying the definition of metered kWh for purposes of the LTS Rider FAC charge. Do you agree?**

A. Yes, with one minor modification. Staff's recommendation is to change the wording in the LTS tariff to read "Applicable to 103.5% of metered kilowatt-hours (kWh) of energy." I agree with Staff's recommended location of the change, but I recommend a more generic statement of "Fuel and Purchased Power Adjustment (Rider FAC) - Applicable to all metered kilowatt-hours (kWh) of energy plus energy line losses from use of the transmission system(s) outside Company's control area." My proposed language allows us to adapt to potential future changes in transmission line losses, while Staff's proposed language does not. Including Ameren Missouri's proposed language in the LTS tariff would also reduce the Voltage Adjustment Factor in the Rider FAC for Transmission Service compared to what the Company originally filed; specifically it would be reduced from 1.0327 to 0.9985.

### c. <u>Opt-Out for Remote Meter Reading</u>

**Q. What is the Staff's recommendation regarding an opt-out option for remote meter reading?**

A. Staff recommends Ameren Missouri implement a non-standard meter program similar to the non-standard meter program that has been approved for use by KCPL-GMO. Staff also recommends Ameren Missouri keep track of the costs associated with the nonstandard meter program, so cost data is available in Ameren Missouri's next rate case to evaluate the one-time setup charge and recurring monthly meter read charge.

**Q. Does the Company agree with Staff's recommendation?**

A. The Company is amendable to including a non-standard metering charge in its tariffs. Since the inception of widespread remote metering in the Ameren Missouri service territory, only 31 customers have requested a manually read meter. It is logical to institute a formal tariffed cost for non-standard metering; e.g. including a one-time setup charge as well as on ongoing charge to reflect the higher cost of manually reading meters. Upon a cursory review of the expected costs of providing non-standard metering, the Company finds the Commission-approved charges for KCP&L-GMO are reasonable and therefore appropriate for Ameren Missouri.

**Q. Where would a non-standard metering service option fit into the Company's tariffs?**

A. I recommend an additional paragraph be added to the Measurement of Service Chapter of the General Rules and Regulation portion of the Company's tariff. Specifically, the additional paragraph should say:

> Customers receiving Residential Service have the option of refusing the installation of remotely read metering or requesting the removal of previously installed remotely read metering. In such instances, non-standard metering equipment will be installed that requires a manual meter read. Customers requesting non-standard metering service after June 1, 2017 will be charged a one-time setup charge of $150 and a monthly recurring Non-Standard Meter Charge of $45 per month.

### d. <u>Seasonality of Rates</u>

**Q. Does the Company agree with Staff's suggestion to study the movement toward Seasonal and Shoulder rates?**

A. No, not at this time. The effect of combining summer and winter rates would necessarily lessen the current summer rate and increase its winter rate, which could theoretically cause a price responsive increase in summer loads. Furthermore, Figure 4 of Mr. Wills' rate design rebuttal testimony shows that summer peaks remain significantly higher than non-summer peaks. It may be worthwhile to explore such an analysis sometime in the future, but only if it were paired with the ubiquitous application of time of day or other peak pricing rate option.

**Q. Does this conclude your rate design rebuttal testimony?**

A. Yes, it does.

**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 Annual Revenues for Electric Service. | ) ) ) | File No. ER-2016-0179 |

**AFFIDAVIT OF WILLIAM R. DAVIS**

**STATE OF MISSOURI** )
) **ss**
**CITY OF ST. LOUIS** )

William R. Davis, being first duly sworn on his oath, states:

1. My name is William R. Davis. I am employed by Ameren Missouri as Director, Energy Efficiency and Renewables.

2. Attached hereto and made a part hereof for all purposes is my Rebuttal Testimony on behalf of Union Electric Company, d/b/a Ameren Missouri, consisting of 39 pages and Schedule(s) WRD-RDR1 & WRD-RDR2, all of which have been prepared in written form for introduction into evidence in the above-referenced docket.

3. I hereby swear and affirm that my answers contained in the attached testimony to the questions therein propounded are true and correct.

William R Davis
William R. Davis

Subscribed and sworn to before me this 24th day of January, 2017.

Mary Hoyt
Notary Public

My commission expires: 4-11-2018

Mary Hoyt - Notary Public
Notary Seal, State of
Missouri - Jefferson County
Commission #14397820
My Commission Expires 4/11/2018

# Light Emitting Diode (LED) Street and Outdoor Area Lighting Report

January 2017

## Executive Summary

Key Insights

- The LED fixture market continues to mature with new product lines continually being offered and the price of LED fixtures continuing to decline as manufacturing volumes increase.
- Manufacturers are beginning to cease production of certain traditional lighting products as the market transition to LED fixtures accelerates.
- In the final three quarters of 2016, Ameren Missouri installed approximately 15,000 LED fixtures under its commitment to begin converting enclosed and open-bottom type fixtures.
- Directional floodlights, constituting 20% of the quantity and 50% of the energy of the Company-owned street and outdoor area lights not already covered by an LED conversion program, now have LED alternatives that are technically and economically feasible.
- The Company plans to install approximately 3,000 directional/flood LED lights per year over a period of approximately five years beginning in the 3rd quarter of 2017.
- Rates for the most common LED directional/flood lights will be about $2 per month less than the current offerings, which is approximately an 8% reduction in the monthly charge.
- Conversion of the directional/flood lights to LED will, once complete, result in a reduction of approximately 19,000 MWH in energy use and nearly 18,000 metric tons of carbon production annually.

If approved by the Missouri Public Service Commission, Ameren Missouri will begin implementing LED lighting for its directional/flood light types beginning in the 3rd quarter of 2017 with full conversion of those light types anticipated in five years. While the number of lights, about 14,000, is relatively small, directional/flood lights are the most energy intensive lighting product offered. Once conversion is complete, energy consumption and carbon production will be reduced by more than 19,000 MWH and 18,000 metric tons per year, respectively. Both customer rates and the associated Fuel Adjustment Charge (FAC) costs will be lower than for the traditional Rate 5M offerings resulting in customer savings of $400,000 per year once complete.

## Technology Assessment Update

LED lighting technology has been experiencing three major trends in recent years. Prices have been decreasing, efficiency and rated life have been increasing and color temperatures have become “warmer.” While LED commercial products continue to evolve along these lines, there were not any technological “break-through” events in 2016 that impact Ameren Missouri’s current LED analysis. For a review of LED technological issues, please see the “December 2015 Light Emitting Diode (LED) Street and Outdoor Area Lighting Report”.

In 2016, certain of Ameren’s suppliers for traditional HID lighting products announced they would discontinue producing certain fixtures. In particular, Ameren is no longer able to purchase directional/flood fixtures from our primary supplier and will instead rely on a secondary supplier until the anticipated commencement of LED conversion in 3rd Quarter 2017 for these fixtures. This is a natural consequence of the overall market transitioning to LED lighting.

## Cost Effectiveness Analysis

The cost effectiveness analysis performed for LED street and outdoor area lights compared the additional up-front cost of LED street and outdoor area lighting fixtures to the additional benefits of those LEDs over their expected useful life. If the additional benefits of LED street and outdoor area lights are greater than the additional costs then conversion is cost effective; it is then also important to understand the period of time that passes before the benefits outweigh the costs. This is the same methodology that was utilized in 2015 and explained in the “December 2015 Light Emitting Diode (LED) Street and Outdoor Area Lighting Report”.

LED conversion of enclosed and open bottom light types commenced April 2016.

With respect to directional/flood lights, the results included in Appendix B indicate that 100% of the High-Pressure Sodium (HPS) lights installed, once converted to LED, become cost effective on or before the second time that maintenance would have been required (11 years). Metal Halide (MH) and Mercury Vapor (MV) lights become cost effective somewhat sooner than HPS lights because they use more energy.

Conversion of decorative post top lights is not cost effective at this time. Post top LED fixtures, while readily available, still have a very high price premium compared to traditional post top fixtures. Ameren Missouri will continue to monitor the evolution of post top LED products and consider other implementation approaches so that they can be offered to customers when they become cost effective.

## Customer Rates

As part of rate design rebuttal testimony in File No. ER-2016-0179, Ameren Missouri has filed a proposed revision to the Rate 5M Street and Outdoor Area Lighting – Company-owned tariff. The tariff includes three new LED options that, if approved, provide for directional/flood lights to become a part of Ameren Missouri's LED conversion program beginning approximately July 1, 2017.

The three new LED options are outlined in the table below. In short, they represent an LED equivalent for each size of currently available directional/flood lighting option. These LED options are based on the cost effectiveness analysis presented earlier in this document.

| | **LED Input Watt (1)** | **Existing Technology Lumens** | **LED Annual kWh** | **Existing Technology Annual kWh** |
|---|---|---|---|---|
| **Directional - Small** | 89 | HPS:25,500<br>MV: 20,000 | 356 | HPS: 1,224<br>MV: 1,908 |
| **Directional - Medium** | 150 | HPS: 50,000<br>MH: 34,000<br>MV: 54,000 | 600 | HPS: 1,892<br>MH: 1,800<br>MV: 4,380 |
| **Directional - Large** | 297 | MH: 100,000 | 1,188 | MH: 4,308 |

(1) Since lumens are not comparable between LED and traditional technologies, Ameren Missouri will classify LEDs according to input watts.

It is important to recognize that the LED alternatives use 65-85% less energy than the existing lighting options offered by Ameren Missouri. After about five years an additional 7% of the lighting system will be converted to LEDs. This will reduce the total 5M rate class energy consumption by another 13%. Ameren Missouri's proposed rates are predicated on the changes in key variable costs between the two lighting technologies. Those two variable costs are 1) the reduction in net base energy costs and 2) the reduction in maintenance costs. The table below demonstrates the calculation of the LED rates that are incorporated in the draft tariff.

| | **Reduction in Monthly Net Base Energy Cost (1)** | **Monthly Maintenance Cost in Current HPS Rate** | **Total Reduction in Variable Costs** | **Current HPS, MH & MV Rates** | **Proposed LED Rate Based on ER-2014-0258 Costs (2) (% Reduction)** |
|---|---|---|---|---|---|
| **Directional - Small** | $1.34 | $0.62 | $1.96 | $22.76 | **$20.80 (8.6%)** |
| **Directional - Medium** | $1.99 | $0.62 | $2.61 | $36.00 | **$33.39 (7.3%)** |
| **Directional - Large** | $4.80 | $0.62 | $5.42 | $71.96 | **$66.54 (7.5%)** |

(1) The monthly Net Base Energy Cost used for pricing LEDs is based on the current lighting technology being installed which is HPS for the small and medium sizes and MH for the large size.
(2) The rates in tariff Sheet No. 58 filed as Schedule WRD-2 in Bill Davis' rate design rebuttal testimony of File No. ER-2016-0179 also reflect the 6.755% increase proposed for Rate 5M.

In addition to the reduction in the monthly base charges above, the LED alternatives will result in a reduction in Fuel Adjustment Charges ("FAC") on monthly bills. Because the FAC charges are assessed on a per kWh basis and LEDs use much less energy compared to existing HPS, MH and MV lights, the FAC savings could become more meaningful although they are not material at the FAC rate of $0.0006 per kWh effective October 2016 through January 2017.

## Implementation Timing

Steps that are necessary for Ameren Missouri to begin implementation of an LED conversion of directional/flood light types are: 1) evaluate specific products/vendors, 2) competitively bid the LED product types targeted for implementation and secure contracts with a vendor(s), 3) build necessary inventory levels consistent with vendor lead times, 4) draw down inventory of discontinued sodium and mercury light stock 5) educate customer service personnel on the new LED lighting offerings and proper application, and 6) educate operations personnel on proper LED installation and process changes necessary to support material tracking and customer billing.

Based on our past experience and the discontinuance of traditional fixtures by Ameren Missouri's primary supplier, steps 1) and 2) have already been completed and step 4) is underway. Steps 3), 5) and 6) will need to begin during the 2nd quarter of 2017 if implementation is to commence in the 3rd quarter of 2017.

## Conclusions

The economic analysis demonstrates that it is now cost effective to transition directional/flood style lights to LED alternatives. An important aspect of the economic analysis is that the lights are converted to LEDs on an "as fail" basis. Leveraging the fact that a worker would already be visiting the location of a failed light lowers the cost of conversion. Ameren Missouri believes the savings in costs with this implementation approach and the immediate bill savings to customers will outweigh the medium-term mixing of lighting differences between HPS and LED technologies. As existing lights fail and new lights are installed, customers will immediately save approximately 8% per month for the new LED lights. After five years of implementation, nearly all of the 14,000 directional/flood style will be replaced with LEDs in the most cost effective manner. While post top style lights are not cost effective today, Ameren Missouri will continue to evaluate the economics of these light types and look for future implementation opportunities as these products evolve.

The status report for LED installations occurring in 2016 follows as Appendix A.

Appendix A

**Status of LED Conversion Program – 2016 Installations**

**(4/1/2016 - 12/31/2016)**

1) Number of fixtures replaced with LEDs: 15,065
2) Discussion of maintenance issues – There have not been any LED fixtures that have failed after being placed in service. Approximately a dozen fixtures were damaged during installation as operational personnel became familiar with the new equipment. Those fixtures were not placed into service and were returned to the manufacturer for repair.
3) Costs associated with LED conversion: $4,213,705.21 recorded to FERC Account 373.002 that was set up to record all LED installations.
4) Total Revenue of 5(M) Company-Owned Street and Area Lighting rate class: $36,876,240 (1)
5) Kilowatt-hour consumption of the 5(M) Company-Owned Street and Area Lighting rate class: 136,799,809 kWh (1)
6) Number of customers making early conversion requests: Zero. While there have been a number of inquiries, no customers have submitted applications and committed to payment of the conversion fee.

Note (1): From File No. ER-2016-0179 True-Up

## Appendix B

| | | | | | Fixture Replacment Cost ($) | | | NPV Maintenance Savings ($) | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Light Style (1)** | **Light Type** | **Lumens** | **Input Watts** | **Quantity Installed** | **Repair Existing** | **LED Install Cost** | **LED Additional** | **Second Trip** | **Third Trip** | **NPV of Energy Benefits** | **Total Net Benefit of LED** | **Payback (Yrs)** |
| Post Top - Colonial | HPS | 9,500 | 117 | 25,403 | $ 77.26 | $ 387.84 | $ 310.58 | $ 64.91 | $ 119.74 | $ 115.38 | $ (75.45) | NA |
| Post Top - Early American | HPS | 9,500 | 117 | 9,348 | $ 77.26 | $ 376.40 | $ 299.14 | $ 64.91 | $ 119.74 | $ 113.80 | $ (65.59) | NA |
| Post Top - Contemporary | HPS | 9,500 | 117 | 4,518 | $ 77.26 | $ 887.99 | $ 810.73 | $ 64.91 | $ 119.74 | $ 107.48 | $ (583.50) | NA |
| Post Top - Aspen | MV | 9,500 | 117 | 3,406 | $ 77.26 | $ 773.54 | $ 696.28 | $ 64.91 | $ 119.74 | $ 107.48 | $ (469.05) | NA |
| Post Top - Colonial | MV | 6,800 | 206 | 5,357 | $ 78.29 | $ 387.84 | $ 309.55 | $ 65.87 | $ 121.60 | $ 256.06 | $ 68.11 | 11 |
| Post Top - Early American | MV | 6,800 | 206 | 1,971 | $ 78.29 | $ 376.40 | $ 298.11 | $ 65.87 | $ 121.60 | $ 254.48 | $ 77.97 | 11 |
| Post Top - Contemporary | HPS | 6,800 | 206 | 953 | $ 78.29 | $ 887.99 | $ 809.70 | $ 65.87 | $ 121.60 | $ 248.15 | $ (439.94) | NA |
| Post Top - Aspen | HPS | 6,800 | 206 | 718 | $ 78.29 | $ 773.54 | $ 695.25 | $ 65.87 | $ 121.60 | $ 248.15 | $ (325.49) | NA |
| Post Top - Colonial | MV | 3,300 | 118 | 99 | $ 72.68 | $ 387.84 | $ 315.16 | $ 60.64 | $ 111.48 | $ 116.96 | $ (86.71) | NA |
| Directional | HPS | 25,500 | 306 | 3,561 | $ 78.60 | $ 419.77 | $ 341.17 | $ 66.16 | $ 122.16 | $ 342.99 | $ 123.98 | 11 |
| | HPS | 50,000 | 473 | 3,764 | $ 78.88 | $ 516.29 | $ 437.41 | $ 66.42 | $ 122.67 | $ 510.53 | $ 195.79 | 11 |
| | MH | 34,000 | 450 | 5,232 | $ 82.83 | $ 516.29 | $ 433.46 | $ 70.11 | $ 129.79 | $ 474.18 | $ 170.52 | 11 |
| | MH | 100,000 | 1077 | 951 | $ 90.33 | $ 767.27 | $ 676.94 | $ 77.11 | $ 143.33 | $1,232.87 | $ 699.26 | 8 |
| | MV | 20,000 | 294 | 302 | $ 78.83 | $ 419.77 | $ 340.94 | $ 66.38 | $ 122.58 | $ 613.27 | $ 394.91 | 7 |
| | MV | 54,000 | 1095 | 23 | $ 90.73 | $ 516.29 | $ 425.56 | $ 77.48 | $ 144.05 | $1,493.67 | $ 1,212.16 | 5 |

HPS = High Pressure Sodium    MV = Mercury Vapor    MH = Metal Halide    NA = Does not pay back in first 15 years.

| | |
|---|---|
| Directional and Post Top Lights | 65,606 |
| Directional only | 13,833 |

(1) Quantities of each style of Post Top light were estimated based on two years of purchasing data.
It is important to analyze each style of Post Top individually since there are significant cost variations across types.

**SERVICE CLASSIFICATION NO. 5(M)**
**STREET AND OUTDOOR AREA LIGHTING – COMPANY-OWNED**

* **RATE PER UNIT PER MONTH LAMP AND FIXTURE**

~~The Light Emitting Diode (LED) offerings under section A. below will be made available to customers beginning on or about April 1, 2016.~~

* A. LED bracket mounted luminaire on existing wood pole:

| Identification | Rate |
|---|---|
| 100W Equivalent (1) | $10.59 |
| 250W Equivalent (1) | $17.16 |
| 400W Equivalent (1) | $31.74 |

(1) The equivalent wattage represents the rating of the high pressure sodium lamp that the LED replaces.

The Light Emitting Diode (LED) offerings under section B. below will be made available to customers beginning on or about July 1, 2017.

*** B. LED directional flood luminaire; limited to installations accessible to Company basket truck:

| Identification | Rate |
|---|---|
| Directional - Small | $22.21 |
| Directional - Medium | $35.65 |
| Directional - Large | $71.04 |

Comment [WAM1]: Prices from page 5 of Schedule WRD-1 plus 6.755% Proposed Increase

** C. Standard post-top luminaire including standard 17-foot post:

Comment [WAM2]: Relocated from below so that all active lights available to customers are at the top of the tariff.

| High Pressure Sodium Lumens | Rate* | Mercury Vapor (1) Lumens | Rate* |
|---|---|---|---|
| 9,500 | $24.30 | 3,300 | $22.97 |
| | | 6,800 | $24.30 |

* The High Pressure Sodium and Mercury Vapor offerings under sections ~~B~~D. and ~~C~~E. below ~~will only be available for new installations through on or about March 31, 2016~~are no longer available. ~~After such time,~~ Company will replace these existing fixtures, upon failure, with an LED fixture under section A.

** ~~B~~D. Standard horizontal burning, enclosed luminaire on existing wood pole:

| High Pressure Sodium Lumens | Rate* | Mercury Vapor Lumens | Rate* |
|---|---|---|---|
| 9,500 | $13.25 | 6,800 | $13.25 |
| 25,500 | $19.14 | 20,000 | $19.14 |
| 50,000 | $34.13 | 54,000 | $34.13 |

** ~~C~~E. Standard side mounted, hood with open bottom glassware on existing wood pole:

High Pressure Sodium Mercury Vapor

| Lumens | Rate* | Lumens | Rate* |
|---|---|---|---|
| 5,800 | $10.73 | 3,300 | $10.73 |
| 9,500 | $11.72 | 6,800 | $11.72 |

~~** D. Standard post-top luminaire including standard 17-foot post:~~

| ~~High Pressure Sodium~~ | | ~~Mercury Vapor (1)~~ | |
|---|---|---|---|
| ~~Lumens~~ | ~~Rate*~~ | ~~Lumens~~ | ~~Rate*~~ |
| ~~9,500~~ | ~~$24.30~~ | ~~3,300~~ | ~~$22.97~~ |
| | | ~~6,800~~ | ~~$24.30~~ |

*Indicates Change. **Indicates Reissue. ***Indicates Addition.

**SERVICE CLASSIFICATION NO. 5(M)**
**STREET AND OUTDOOR AREA LIGHTING – COMPANY-OWNED (Cont'd.)**

* The High Pressure Sodium, Metal Halide and Mercury Vapor offerings under sections F. below will only be available for new installations through on or about June 30, 2017. At that time, Company will replace these existing fixtures, upon failure, with an LED fixture under section B.

** ~~E~~F. Pole-mounted, directional flood luminaire; limited to installations accessible to Company basket truck:

| High Pressure Sodium | | Metal Halide | | Mercury Vapor (1) | |
|---|---|---|---|---|---|
| Lumens | Rate* | Lumens | Rate* | Lumens | Rate* |
| 25,500 | $24.30 | 34,000 | $24.30 | 20,000 | $24.30 |
| 50,000 | $38.43 | 100,000 | $76.82 | 54,000 | $38.43 |

(1) Mercury Vapor lamps and fixtures are limited to customers served under contracts initiated prior to September 27, 1988. Company will continue to maintain these lamps and fixtures so long as parts are economically available.

** ~~F~~G. All poles and cable, where required to provide lighting service:

The installation of all standard poles and cables shall be paid for in advance by customer, with all subsequent replacements of said facilities provided by Company.

** ~~G~~H. Former Subsidiary Company lighting units provided under contracts initiated prior to April 9, 1986, which facilities will only be maintained by Company so long as parts are available in Company's present stock:

| Lamp and Fixture | *Per Unit Monthly Rate |
|---|---|
| 11,000 Lumens, Mercury Vapor, Open Bottom | $11.72 |
| 140,000 Lumens, H.P. Sodium, Directional | $76.82 |

Term of Contract Minimum term of three (3) years where only standard facilities are installed; ten (10) years where post-top luminaires are installed.

Discount for Franchised Municipal Customers A 10% discount will be applied to bills rendered for lighting facilities served under the above rates and currently contracted for by municipalities with whom the Company has an ordinance granted electric franchise as of September 27, 1988. The above discount shall only apply for the duration of said franchise. Thereafter, the above discount shall apply only when the following two conditions are met: 1) any initial or subsequent ordinance granted electric franchise must be for a minimum term of twenty (20) years and 2) Company must have a contract for all lighting facilities for municipal lighting service provided by Company in effect.

*Indicates Change. ** Indicates Reissue.

**SERVICE CLASSIFICATION NO. 5(M)**
**STREET AND OUTDOOR AREA LIGHTING – COMPANY-OWNED (Cont'd.)**

** Payments Bills are due and payable within twenty-one (21) days from date of bill and become delinquent thereafter.

Tax Adjustment Any license, franchise, gross receipts, occupation or similar charge or tax levied by any taxing authority on the amounts billed hereunder will be so designated and added as a separate item to bills rendered to customers under the jurisdiction of the taxing authority.

Fuel and Purchased Power Adjustment (Rider FAC) The kilowatt-hours for lighting service provided under the terms of this Service Classification shall be subject to the provisions of Company's Fuel and Purchased Power Adjustment Clause (Rider FAC). The kilowatt-hour consumption of each lamp, whose operating hours are determined by a photoelectric control, shall be determined from the manufacturer's rated wattage multiplied by the number of hours of operation for the month, in accordance with the following schedules:

| * LED Bracket Mounted (Watts) | * LED (Watts) | Billing Month | Burning Hours |
|---|---|---|---|
| 100W Equivalent | 48 | January | 408 |
| 250W Equivalent | 88 | February | 347 |
| 400W Equivalent | 195 | March | 346 |
| | | April | 301 |
| * LED Directional Flood | * LED (Watts) | | |
| Small | 89 | | |
| Medium | 150 | | |
| Large | 297 | | |
| Lamp Size (Lumens) | Rating (Watts) | May | 279 |
| | | June | 255 |
| H. P. Sodium | | July | 272 |
| 5,800 | 70 | August | 298 |
| 9,500 | 120 | September | 322 |
| 16,000 | 202 | October | 368 |
| 25,500 | 307 | November | 387 |
| 50,000 | 482 | December | 417 |
| 140,000 | 1000 | | |
| Mercury Vapor | | | |
| 3,300 | 127 | | |
| 6,800 | 207 | | |
| 11,000 | 294 | | |
| 20,000 | 455 | | |
| 42,000 | 700 | | |
| 54,000 | 1080 | | |

| | |
|---|---|
| Metal Halide | |
| 34,000 | 450 |
| 100,000 | 1100 |

*Indicates Change. **Indicates Addition.

**SERVICE CLASSIFICATION NO. 5(M)**
**STREET AND OUTDOOR AREA LIGHTING – COMPANY-OWNED (Cont'd.)**

* **1. RATE APPLICATION**

Available for lighting streets, alleys, walkways and other thoroughfares, or for outdoor lighting of public or private areas for security or similar purposes when such lighting facilities are operated and maintained as an extension of Company's distribution system.

* **2. CHARACTER OF SERVICE SUPPLIED**

Company shall inventory, furnish, install, maintain and deliver electric service to automatically-controlled lighting fixtures currently offered as standard facilities by Company. Customer shall select the type and size of lamps and fixtures from the standard equipment inventoried and offered by the Company and shall specify the location of said fixtures. Other than service to Company's post-top fixtures, the service provided hereunder shall be supplied by lines or cables through fixtures supported by standard upsweep brackets attached to existing poles; however, certain non-standard facilities may be installed hereunder in accordance with the terms and conditions stated in the following paragraph 3.

* **3. NON-STANDARD FACILITIES**

Whenever customer requires Company to install non-standard facilities hereunder (such as longer upsweep brackets, switches, protective barriers, etc.) and there is no engineering, construction, safety, legal or practical reason which would, in Company's judgment, make such non-standard installation inadvisable, Company will make such installation provided customer pays in advance to Company all costs in connection therewith. Subsequent replacements of said facilities will be provided by the Company.

**4. CONVERSION OR MODIFICATION OF LAMPS**

** Where customer requests a conversion or modification of the size or type of lamp currently installed, and Company would not otherwise be converting such lights at that time, Company will make the requested changes, within the parameters described below, provided that customer pays in advance to the Company $100.00 per lamp for both the removal cost and loss of the remaining life of such lamps and, additionally, signs a new contract at the time when 20 percent or more of the customer's total lamps then installed are so converted or modified. Billing for the revised lamps will be prorated based on the removal and installation dates.

*Indicates Reissue **Indicates Change

**SERVICE CLASSIFICATION NO. 5(M)**
**STREET AND OUTDOOR AREA LIGHTING – COMPANY-OWNED (Cont'd.)**

**4. CONVERSION OR MODIFICATION OF LAMPS (Cont'd.)**

* Company will convert to LED up to 1,000 lights per year requested by customers. Customer requests for LED lights will not be accepted prior to April 1, 2016 and will be limited to twenty-five (25) lights per customer account per calendar year. Customer requests must be in writing and, at a minimum, identify the specific physical location and billing account number and service date requested of each light. In the event Company determines it cannot accommodate all requests for conversions in the timeframes requested, prioritization of the requests will be at Company's discretion.

**5. CHANGE OR RELOCATION**

Upon receipt of written request and authorization from customer, Company will, insofar as it may be practical and permissible, make any other change in or relocation of its facilities used in rendering service hereunder, provided customer pays in advance Company's estimated costs in connection therewith.

** **6. ADDITIONAL INSTALLATIONS**

Customer may obtain the installation of additional lamps and the supply of service thereto under the existing contract for the remainder of the term thereof upon written application to the Company, provided, however, that if at any time during the term of the contract customer requires such additional lamps so as to cause the total number of lamps in service to exceed by 20% the lamps originally contracted for and then installed, the parties shall execute a new contract.

** **7. TERMINATION**

If customer requests in writing the termination of all or a portion of any lighting service, not paid for in advance, within three years of the installation of the lamps being terminated, or within ten years of the installation of post top luminaires, wood poles or cable being terminated, customer shall pay in advance to Company $100.00 per lamp for both the removal costs associated therewith and the loss of the remaining life value of such facilities. If said request for termination of lighting service is made after the above three and ten year in-service periods, as applicable, and customer requests a new lighting installation within twelve months after the removal of the prior terminated lighting facilities, customer shall pay the amount specified earlier in this paragraph for all facilities previously removed prior to Company making any new lighting installation.

*Indicates Addition **Indicates Reissue

**SERVICE CLASSIFICATION NO. 5(M)**
**STREET AND OUTDOOR AREA LIGHTING – COMPANY-OWNED (Cont'd.)**

**8. GENERAL PROVISIONS**

Customer shall furnish to Company without cost to Company and on forms suitable to it, or customer shall reimburse Company for all costs incurred in obtaining all rights, permits and easements necessary to permit the installation and maintenance of Company's facilities on, over, under and across both public and private property where and as needed by Company in providing service hereunder. In addition, customer shall pay all costs incurred by Company in extending its distribution system, including transformers, to provide energy to said lighting facilities supplied hereunder, in accordance with the provisions of Section III.Q - Special Facilities.

**9. GENERAL RULES AND REGULATIONS**

In addition to the above specific rules and regulations, all of Company's General Rules and Regulations shall apply to service supplied under this Service Classification.