MISSOURI PUBLIC SERVICE COMMISSION

STAFF REPORT

CLASS COST OF SERVICE

UNION ELECTRIC COMPANY,
d/b/a Ameren Missouri

CASE NO. ER-2019-0335

Jefferson City, Missouri
December 18, 2019

** Denotes Confidential Information **

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I. Executive Summary

In Staff's *Cost-of-Service Report* ("COS Report") filed December 4, 2019, Staff recommended a revenue requirement for Union Electric Company, d/b/a Ameren Missouri ("Ameren Missouri") of approximately $2.525 billion, at its recommended rate of return of 6.921%, based on Ameren Missouri's actual costs through June 30, 2019, net of other revenue of approximately $400 million, a decrease of approximately $65 million from its current retail rate revenues of approximately $2.59 billion, a decrease of approximately 2.5%. Please note that this decrease is applicable to the currently tariffed rate schedules for each class. Because the temporary tax rider is being eliminated as part of this case, but the recommended decrease does not exceed the magnitude of the temporary tax rider, customers will experience a slight increase in bills.

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 any calculated revenue requirement amount. Typically, Staff's recommended interclass revenue responsibility shifts, as applicable, are designed to reasonably bring each class closer to producing the system-average rate of return used in determining Staff's recommended revenue requirement. Staff's recommended intra-class shifts will, where appropriate, redesign the rates that collect a particular class's revenues to better align that class's method of recovering revenue with the cost-causation for that class that was indicated by the class cost of-service study.[1]

A. CCOS Results and Recommended Decrease Implementation Summary

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

[1] Staff studied Ameren Missouri's rate schedules under the classes indicated: 1M Residential ("Res."), 2MSmall General Service ("SGS"), 3M Large General Service ("LGS") and 4M Small Primary Service ("SPS"), 11M Large Primary Service ("LPS"), and Street & Outdoor Area Lighting schedules 5M and 6M ("Combined Lighting").

are required to equalize the utility's rate of return from each class. So long as a class's revenue exceeds the expense portion of its cost of service, the class will be providing some level of return on the capital associated with the net ratebase providing service to that class. Based on Staff's Capacity-Assigned CCOS, all classes are contributing revenues in excess of the expenses associated with providing service, and are contributing to the Company's overall return, satisfying the first metric. However, Staff also evaluated the classes' revenues as a percent of the total assigned and allocated cost of serving that class, including the system average rate of return on net ratebase. The Residential, SGS, and Combined Lighting classes are at a greater than 5% positive variance to their calculated cost to serve and the LPS class is at a greater than 5% negative variance to its cost to serve.

For the reasons that will be discussed below related to the interrelationship of this case with the temporary tax rider and expected Ameren Missouri capital build-out, Staff does not recommend that revenue responsibility be realigned at this time.[2]

If the Commission determines that it is appropriate at this time to realign revenue responsibility consistent with class cost of service and an overall revenue decrease of approximately $65 million is ordered for Ameren Missouri, Staff recommends a decrease of approximately $5 million be implemented to the Lighting Classes, a decrease of approximately $15 million be implement to the Small General Service class, and the remaining decrease of approximately $45 million be implemented to the Residential class. If a smaller decrease is awarded and the Commission determines that it is appropriate at this time to realign revenue responsibility consistent with class cost of service, Staff recommends these amounts be prorated to the indicated classes consistent with the described amounts.

B. Rate Design Recommendation Summary

Staff recommends these cases be used as an opportunity to begin the process of implementing default company-wide Time of Use ("ToU") rates. Because Ameren will not complete deployment of AMI meters for some time, and in the interest of using these introductory ToU rates to educate customers about ToU with minimal customer impact, Staff's recommended

[2] On December 18th Staff became aware that Ameren Missouri was redoing its load research process for approximately half of its test period apparently prompted by Staff DR 517. As indicated on page 49 of the Staff CoS Report, Staff was concerned that anomalies existed for certain months of data. The December 18th discussion further undermines Staff's confidence in the reliability of this data. Reliable load research data is integral to a reasonable CCoS.

ToU design focused on minimizing customer impact, and applying a gradual rollout of the rates. Specifically, Staff recommends that when a customer's AMI meter is installed, the customer begins receiving a "shadow bill" indicating the usage in each interval, and what the customer's energy charges would have been under Staff's recommended ToU rate. Then, approximately 6 months to 1 year after the AMI installation, Staff recommends Ameren Missouri interact directly with that customer to educate the customer as to what that customer's bill would have been during the prior period on the recommended default ToU rate schedule, as well as any of the alternative Ameren ToU schedules that may be approved at that time. Staff recommends that for new customers or new accounts, if an AMI is in place at that premise, new customers be placed on the default ToU rate schedule unless they specifically request otherwise.

For the non-residential classes Staff recommends that the rate reduction be applied as an equal percentage reduction to the demand charges associated with each rate schedule.

C. Tariff and Other Recommendations

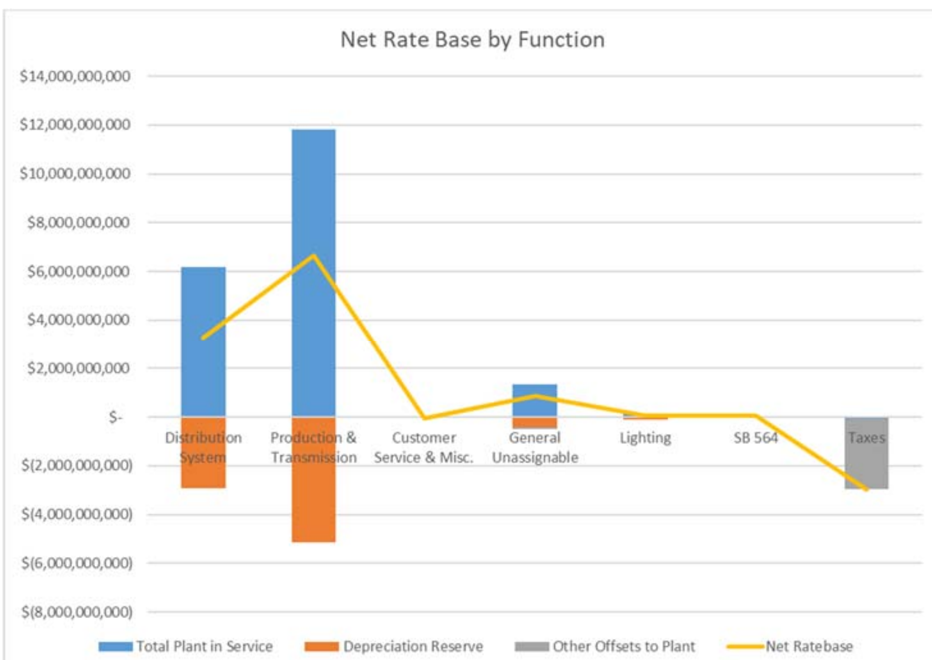
1) Paperless Billing
2) Staff recommends revisions to Ameren Missouri's application of "Billing Period."
3) Staff recommends a number of data retention measures be implemented:
   a) Implement more thorough record keeping or data accessibility practices to better associate distribution system costs with the voltage of energy distributed;
   b) Take steps necessary in its AMI deployment process to provide accurate load research data at a high level of precision, by implementing practices to leverage AMI meter data for load research purposes;
   c) On an ongoing basis, Ameren Missouri should retain interval data for customers with AMI meters be retained for a minimum of a rolling 12 month time period so that customers may compare ToU options;
   d) Study and retain determinants associated with the creation of a coincident peak demand charge for all classes.
4) Staff recommends certain tariffs be updated as part of the compliance process in this case consistent with processes identified within those tariffs:
   a) Update the Facilities Charge on Tariff Sheet 158 (Community Solar Pilot Program) to reflect the changes made to the related energy charges, if applicable;
   b) Update the Renewable Energy Standard Rate Adjustment Mechanism ("RESRAM") Tariff Sheet No. 93.4 to reflect the RESRAM base amount determined in this case;
   c) Update the MEEIA margin rates used for calculating the throughput disincentive within the MEEIA mechanism.

5) Staff recommends this case be taken as an opportunity to implement solutions to certain issues that have arisen in other contexts:
   a) Clarify the billing process for ToU customers;
   b) Revenue Treatment for Potential Customer Renewable Energy Credit Program;
   c) Stipulation and Agreement in ET-2018-0132 concerning line extension record retention.
6) Staff recommends establishment of a ToU rate schedule to be applicable to separately-metered EV charging equipment, on an opt-in basis.[3]
7) Staff recommends modifications to the Fuel Adjustment Clause ("FAC") base factor and transmission percentage.

D. Summary of Bundled and Functionalized Cost Categories

Staff has calculated that the appropriate retail revenue requirement for Ameren Missouri is $2.525 billion, which includes $548 million in return on ratebase, and $578 million in depreciation expense.

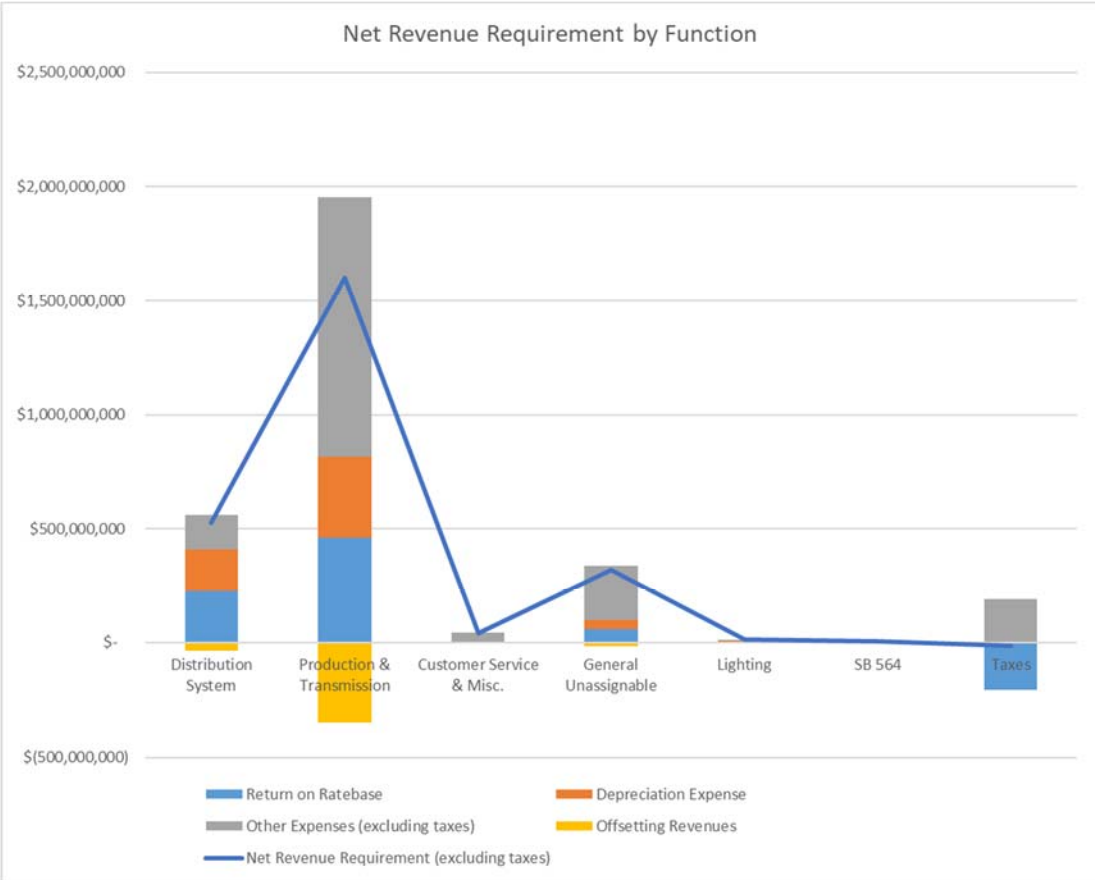
The total plant in service, associated depreciation reserve, other offsets to ratebase (such as deferred taxes), and resulting net plant are depicted below, by function.[4]



[3] At this time, Staff does not object to the general design proposed by Ameren Missouri for this purpose. Final design of this rate is dependent on the revenue requirement established in this matter.

[4] At this time, minimal spending associated with the various statutory provisions encompassed in SB 564 has occurred. As discussed below, Ameren Missouri has announced significant expenditures in its five year capital plan.

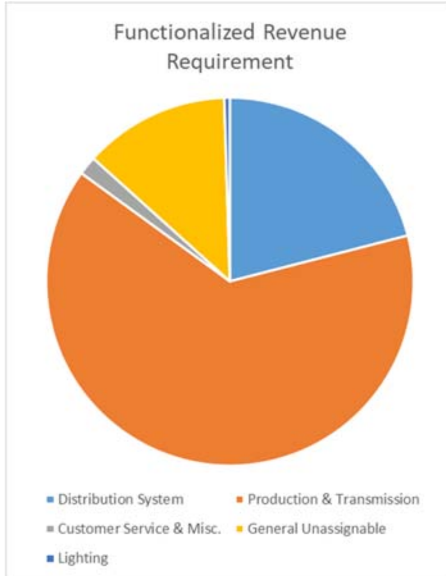
The functionalized return on ratebase, depreciation expense, other expenses, and offsetting revenues are depicted below, with the resulting net revenue requirement, by function. This depiction is useful to observe the magnitude of costs that do not vary with the level of energy sold to retail customers, such as depreciation expense and return on investment, as components of the overall revenue requirement.



The Production & Transmission function includes all of Ameren Missouri's company-owned generating facilities, capacity transactions, fuel purchases, and energy purchases and sales.[5] As readily depicted in the graphs above and below, this function constitutes roughly two-thirds of Ameren Missouri's net revenue requirement.[6] The Distribution System also constitutes a significant portion of the net revenue requirement.

[5] For purposes of this initial discussion, the intra-interval energy purchases and sales transacted through the MISO integrated marketplace are treated as the annual cumulative net recorded sales proceeds and purchased power expenses.

[6] At this time, the net tax function results in an offset to revenue requirement. It is excluded from this pie-chart.



General familiarity with the above magnitudes is helpful for at least three reasons. First, many of the contested issues that arise around cost of service relate to the allocation of generation-related costs and revenues, so it is helpful to observe the relative magnitude of this functionalized cost. Second, Ameren Missouri is embarking on significant capital expenditures, largely in the areas of distribution (smart grid) and generation (wind), so it is useful to be aware of the starting points of each at the outset of this build-out program. Finally, it is useful to be aware of the makeup of the revenue requirement as depicted above prior to contemplating the scale of the actual integrated market transactions through which Ameren Missouri buys and sells roughly a billion dollars of energy every year, which is beginning to render traditionally executed embedded cost of service studies less meaningful.

In the graph below, the Energy-Related portion of the Market-Production subfunction is netted – the fuel, revenue from energy sales, and expenses of purchasing energy to serve load have offset to a net revenue requirement of approximately $400 million.

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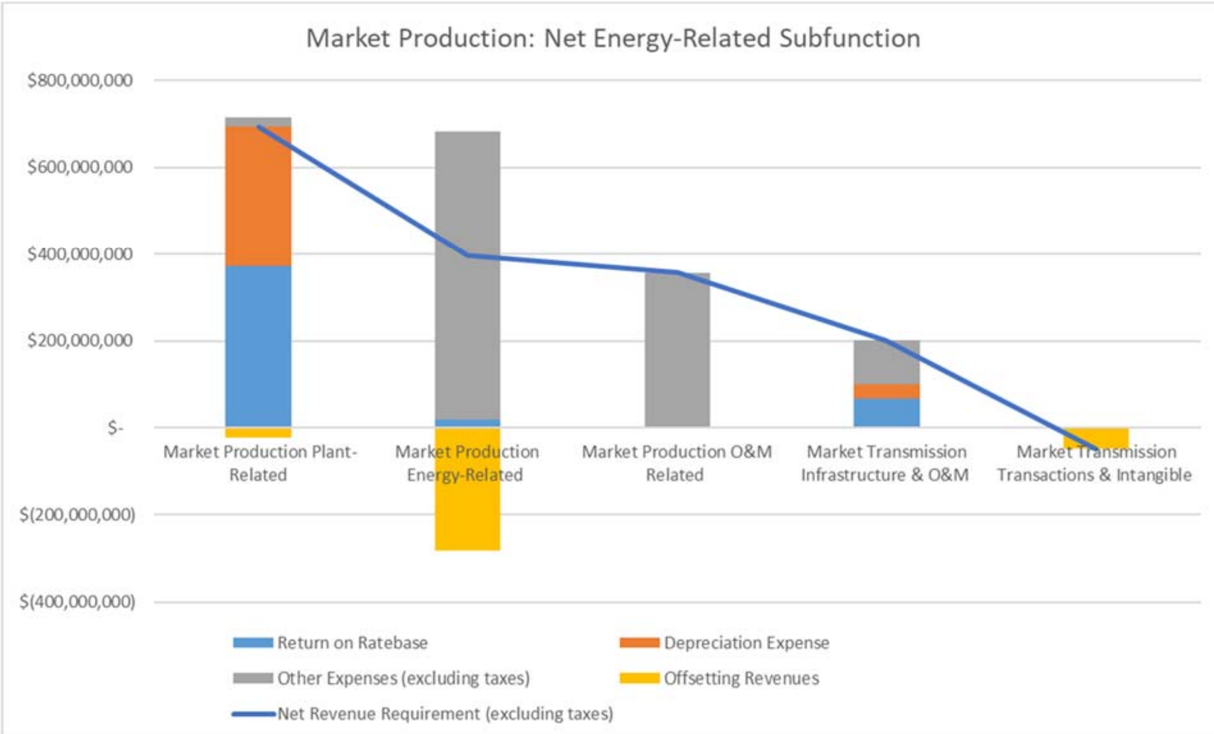

Typically in an embedded cost study, the net revenue requirement of the Plant-Related subfunction would be allocated to customer classes based on a capacity-related allocator, such as Staff's detailed BIP, or one of the several Average & Excess variations; while the net revenue requirement of the Energy-Related subfunction would be allocated to the classes based on an energy-related allocator, such as sales at generation by class, or market-weighted average energy cost. As depicted above, the gross costs of service of the Plant-Related and Energy-Related subfunctions are very similar, and the net revenue requirement of the Energy-Related subfunction is just over half of the magnitude of the net revenue requirement of the Plant-Related subfunction. However, as Ameren Missouri actually operates in the MISO integrated market, the gross Energy-Related subfunction dwarfs the remaining subfunctions within the Market Production function, as is depicted below.

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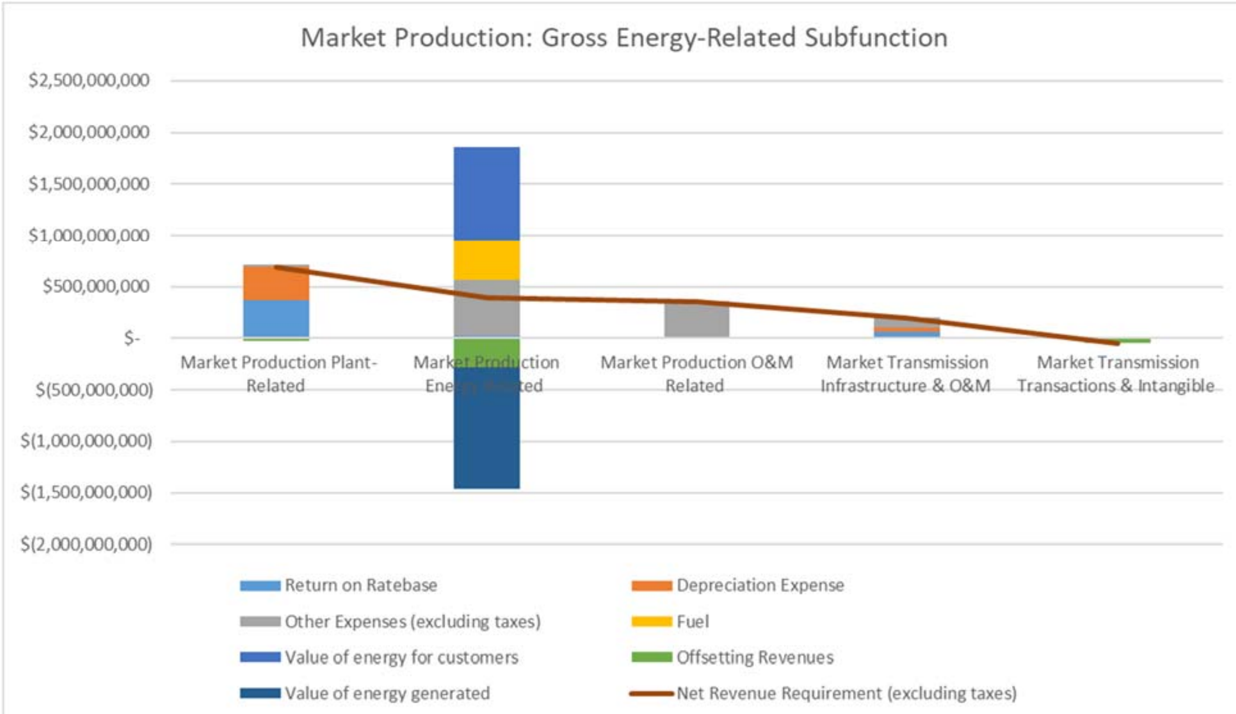


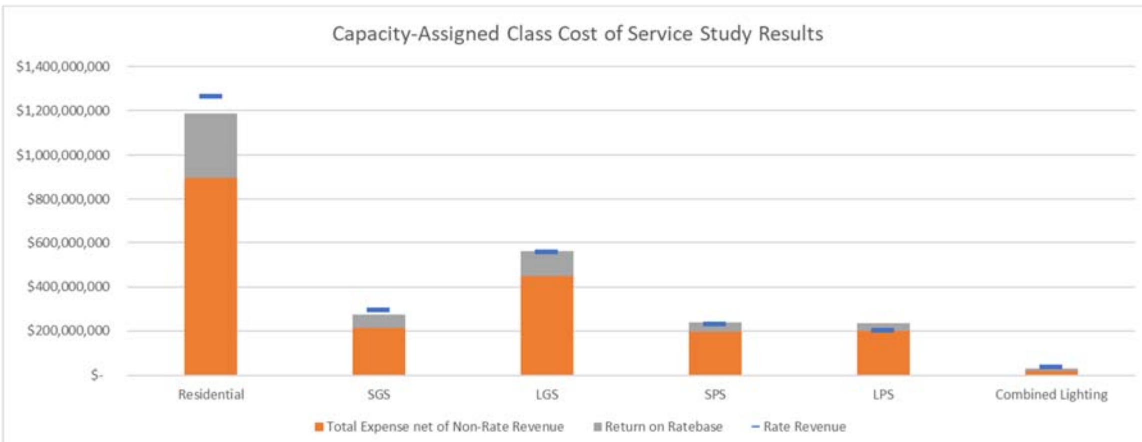
As is depicted above, the value of the energy purchased for customers is approximately $900 million, which is directly assignable to the classes – and customers within the class – causing the purchase of energy. The fuel expenditures of approximately $400 million dollars were modeled to produce energy worth approximately $1.2 billion. Because that production required use of the generating facilities, employees, maintenance costs, and transmission costs including access to the MISO IM, the net proceeds of the generated energy are more reasonably treated as an offset to the costs of production than to the expense of obtaining energy. The possible treatments of the Market Production functionalized revenue requirement will be discussed below.
Staff Expert/Witness: Sarah L.K. Lange

II. Bundled Class Cost of Service Results and Recommended Decrease Implementation

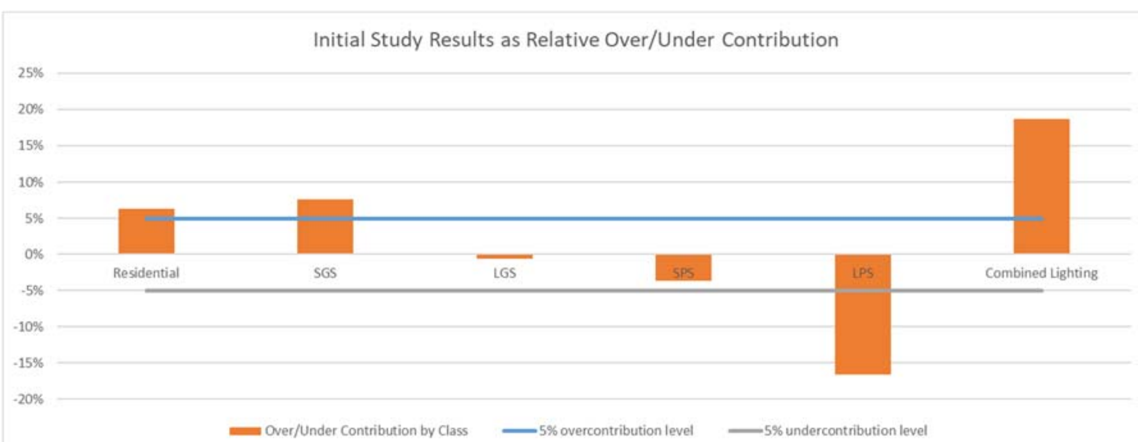
Staff performed its class cost of service study in a manner to facilitate comparison of the impact of selection of allocator on the study results. Specifically, Staff assigned and allocated costs not only to the rate classes Residential, Small General Service, Large General Service, Small Primary Service, and a combined Lighting Class, but also to the functional classes "Market Production & Transmission," "Taxes," "SB 564," and "General Unassignable for Allocation."

Staff bases its recommendations on the Capacity-Assigned Class Cost of Service Study, Version B,[7] the results of which are summarized below:

	Residential	SGS	LGS	SPS	LPS	Combined Lighting
Total Ratebase	$ 4,156,839,847	$ 883,013,497	$ 1,600,160,969	$ 618,671,776	$ 514,632,763	$ 147,002,280
Total Expense net of Non-Rate Revenue	$ 898,940,866	$ 211,110,903	$ 450,112,960	$ 196,596,900	$ 198,864,485	$ 21,497,316
Return on Ratebase	$ 287,694,886	$ 61,113,364	$ 110,747,141	$ 42,818,274	$ 35,617,734	$ 10,174,028
Class Cost of Service at System Average RoR	$ 1,186,635,752	$ 272,224,267	$ 560,860,101	$ 239,415,174	$ 234,482,219	$ 31,671,344
Rate Revenue	$ 1,266,985,066	$ 294,771,201	$ 557,524,661	$ 230,999,514	$ 201,128,512	$ 38,931,311
Current Rate of Return	8.85%	9.47%	6.71%	5.56%	0.44%	11.86%
Decrease to Current Tariff Rates to Exactly Match Calculated Class Cost of Service	**$ 80,349,314**	**$ 22,546,934**	**$ (3,335,440)**	**$ (8,415,660)**	**$ (33,353,707)**	**$ 7,259,967**
% Decrease to Current Tariff Rates to Exactly Match Calculated Class Cost of Service	6.34%	7.65%	-0.60%	-3.64%	-16.58%	18.65%



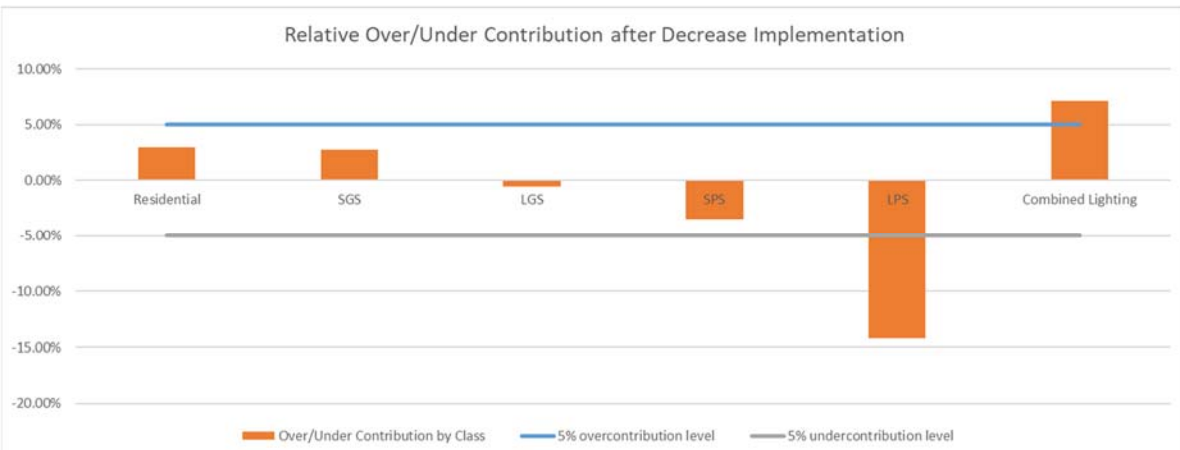
These results indicate that all classes are providing a contribution to rate of return, although some classes are providing a higher return than others.



[7] Staff's studies are referred to as Assigned Capacity - Version A, Assigned Capacity - Version B, A&E 4NCP - Version A, A&E 4NCP - Version B, Assigned Capacity - Plug for Capital Plan A, Assigned Capacity - Plug for Capital Plan B.

As depicted above, the Residential, SGS, and Combined Lighting classes are at a greater than 5% positive variance to their calculated cost to serve at a system average rate of return, while the LPS class is at a greater than 5% negative variance to its cost to serve.

If the Commission chooses to move classes towards the calculated cost of service at this time, and if an overall revenue decrease of approximately $65 million is ordered for Ameren Missouri, Staff recommends a decrease of approximately $5 million be implemented to the Lighting Classes, a decrease of approximately $15 million be implement to the Small General Service class, and the remaining decrease of approximately $45 million be implemented to the Residential class.[8] The resulting variances to the calculated cost to serve at a system-average rate of return are depicted below.



Staff bases its recommendations for implementing a decrease to tariffed rates in this case on its CCOS study results, Staff's review of Ameren Missouri's revenue-neutral adjustments in previous general rate increases, the impact of the temporary tax rider, and anticipated future revenue requirements related to Ameren Missouri's publicly announced capital plans in File No. EO-2019-0044, *In the Matter of the Compliance of Union Electric Company d/b/a Ameren Missouri with Certain Requirements Related to SB 564 and Related Matters*, and Staff's expert judgment regarding the impact of revenue shifts for all classes. As will be discussed later in this Report, primarily for the reason of anticipated future revenue requirements related to Ameren

[8] If a smaller decrease is awarded, Staff recommends these amounts be prorated to the indicated classes. If there is no change in revenue requirement or an increase in revenue requirement is ordered, Staff recommends that no revenue neutral shifts be made.

Missouri's publicly announced capital plans and the impact of the temporary tax rider's removal, Staff does not recommend realigning classes' revenue responsibilities at this time.

A. Distribution Costs

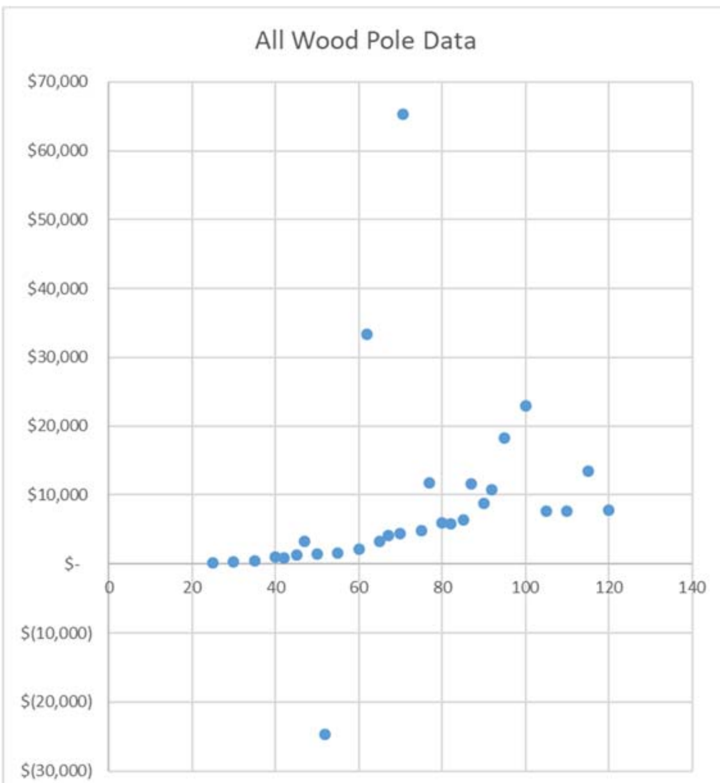
1. Classification

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. Ameren Missouri's distribution plant accounts reflect the costs and expenses associated with the non-transmission high voltage system, distribution substations, poles, wires, and transformers, as well as service and labor expenses incurred for the operation and maintenance of these distribution facilities. Distribution plant Accounts 364 through 370 involve both demand-related and customer-related costs. The customer-related component of distribution facilities is that portion of costs which varies with the total number of customers served. Generally, the number of poles, transformers, meters, and miles of conductor are directly related to the number of customers on the utility's system, but the size of each of these items are related to the level of energy that they deliver over time. The dollars recorded in distribution system accounts need to be apportioned between the customer- and demand-related classifications to facilitate the most reasonable allocation for each portion, and allocated to the various voltages for proper allocation to the classes. This classification relies on a determination of how much of the distribution system is needed to make service available to all customers regardless of the level of any customer's demand versus how much of the distribution system is needed to meet the maximum demand requirements of the customers served, by class.

Account 364

For the Pole account, Account 364, Staff classified the customer-related portion of costs associated with the poles comprising Ameren Missouri's distribution system using the Zero-Intercept Cost Minimum System method. The remaining classification of Account 364 relied on Ameren Missouri's "Vandas" study provided within its workpapers. The concept behind a Zero-Intercept Cost study is to seek to identify that portion of plant related to a hypothetical no-load or zero-intercept situation.[9] The technique is to relate installed cost to current carrying capacity or demand rating, create a curve for various sizes of the equipment involved, using regression techniques, and extend the curve to a no-load intercept. The cost related to the zero-intercept is the customer component. In other words, the Zero-Intercept cost would be the cost that would be recorded in the studied account if, for example, the entire distribution system were operated at zero volts and linemen had been installing 0" tall poles for the last hundred and twenty years. Those are the costs that strictly relate to the number of customers served.

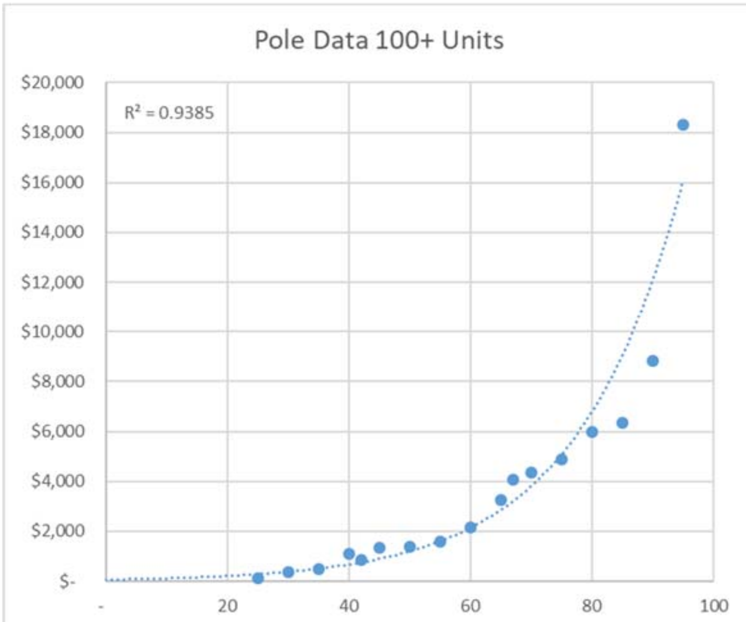
Staff first reviewed the data to determine whether it exhibited trends that would be conducive to producing a reliable Zero Intercept result. This process consists of first graphing all available data to determine whether to expend the resources to proceed. The data to be plotted is the height of the pole along the X axis, by the average cost per unit recorded in Account 364.



Because the plotted results appear to reflect a graphable pattern, Staff then proceeded to identify pole heights where less than 100 poles of that height were installed. Staff removed the

[9] The NARUC Manual says of the Zero-Intercept Method that this method "requires considerably more data and calculation than the minimum-size method. In most instances, it is more accurate, although the differences may be relatively small."

data associated with pole-types that were not commonly installed because, (1) it is likely that atypical poles were installed to do circumstance unique to that pole's installation, and (2) because higher-volume unit recordings are more likely to average out unique installation circumstances or recording errors. The plotted data for cost-per unit of wood poles from 25' – 95' tall, and an Excel-generated exponential trendline are provided on the graph below:



This dataset reflects the average cost per unit of 893,851 poles, of 17 heights, with a gross cost of $833,062,796, and regresses to a line that is visually reasonable, generating an R^2 value of 0.9385. Based on these factors, it is not unreasonable to proceed with a Zero Intercept study of for the Pole account, Account 364.

Literally "zooming in" on the portion of the plot that shows the average cost of poles 40' and below, and includes the regression line described above, we can begin to see where the regression line will cross the Y axis, which extrapolates the historic cost per unit of a 0" tall pole.

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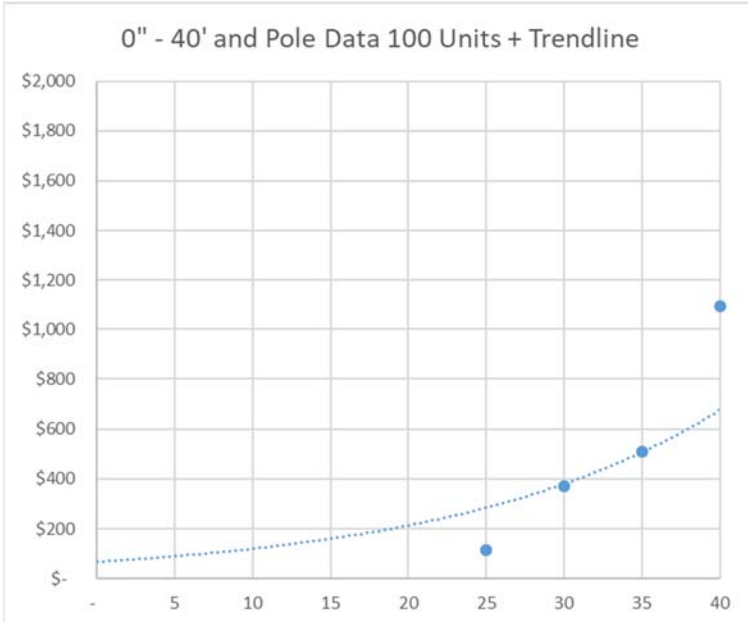
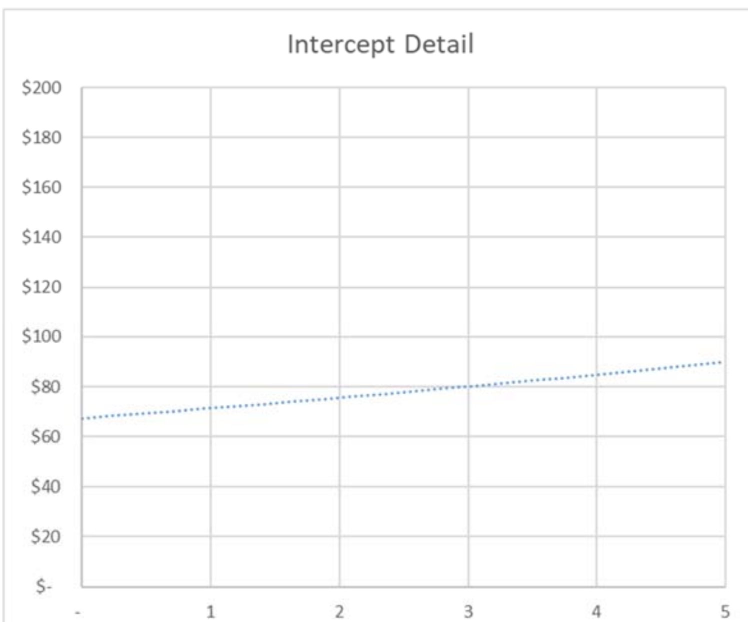
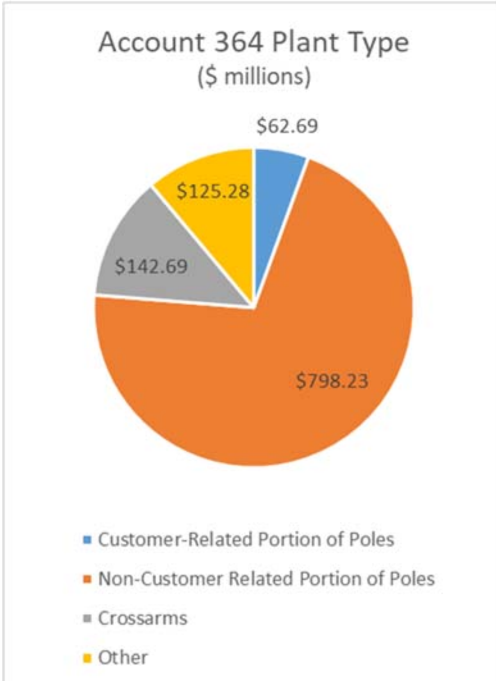
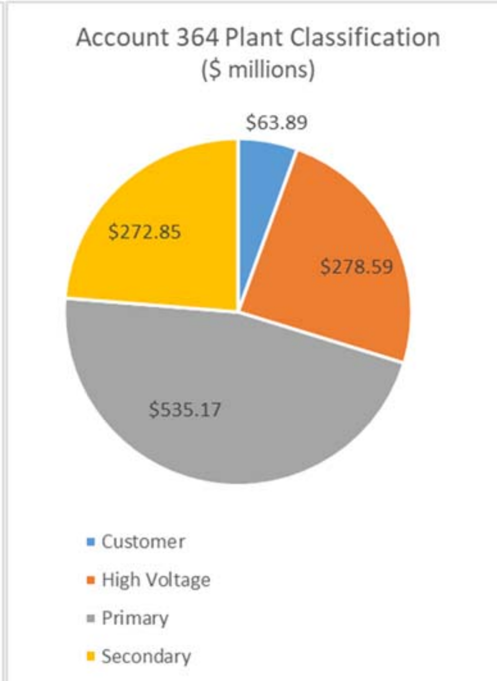


In the interest of providing a conservative result, Staff estimates the visual Y intercept at a historic cost per unit of $70, observed from the detail of the 0” – 5’ portion of the Pole Data 100+ Units plot and regression, provided below.



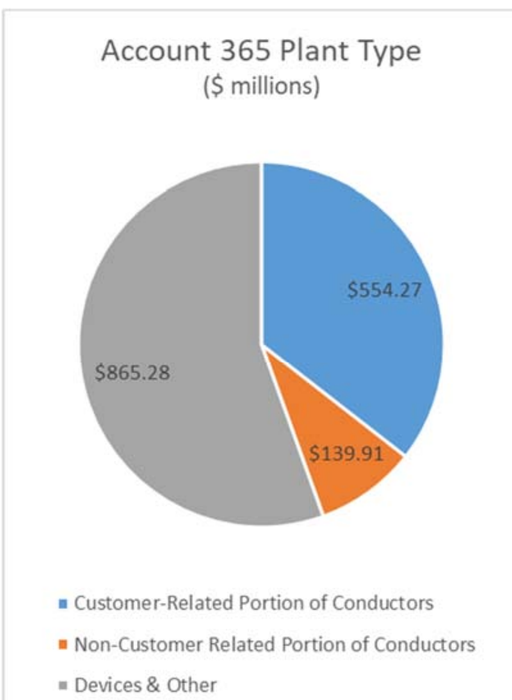
Relying on a $70 per pole estimate, the Customer -related portion of Account 364 is approximately $62 million dollars, or approximately 7% of the portion of account 364 related to poles, towers, and similar structures. Staff classified the remainder of Account 364 relying on Ameren Missouri’s presentation of the Vandas study in its workpapers.

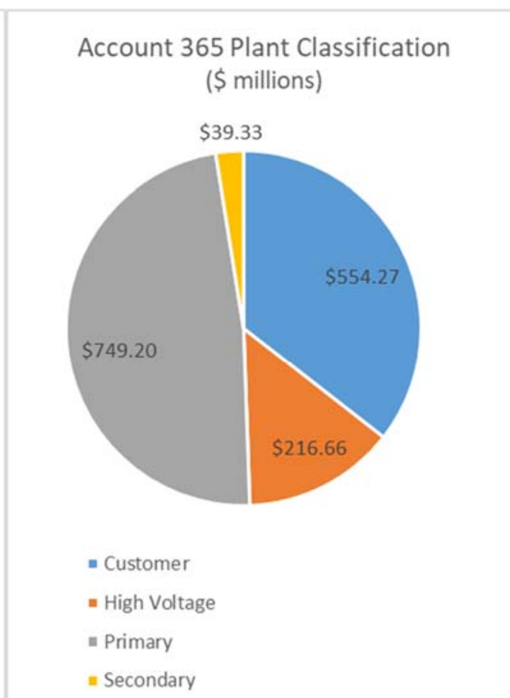




Account 365

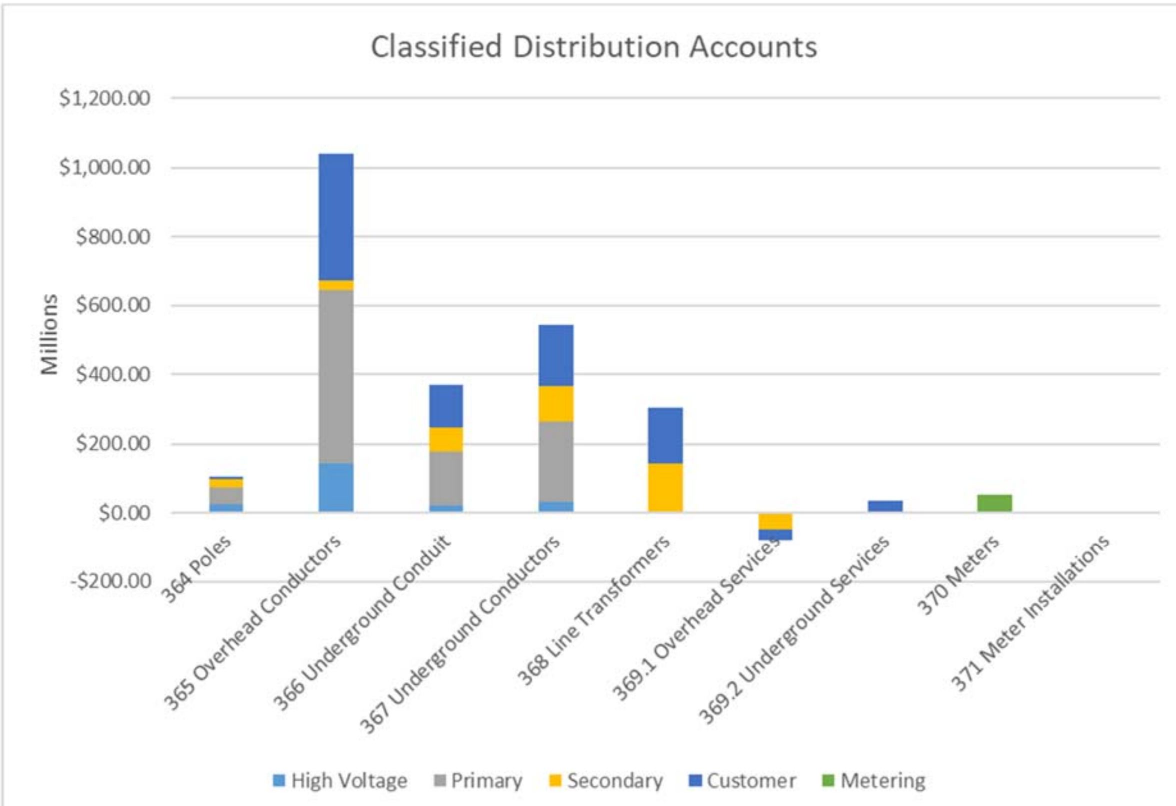
For Account 365, Overhead Wires and Devices, Staff used the average cost of conductor to establish the customer-related classification, and classified the remainder of Account 365 relying on Ameren Missouri's presentation of the Vandas study in its workpapers.



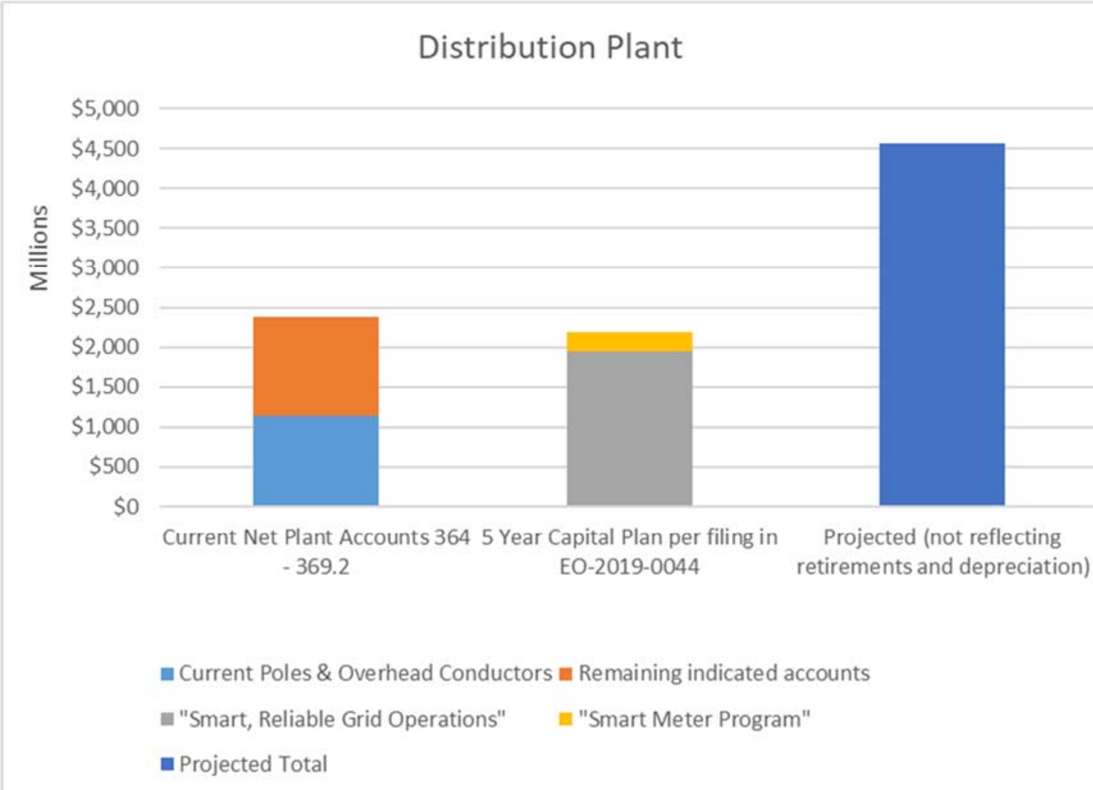


Other Distribution Accounts

Staff relied on Ameren Missouri's classification of Accounts 360 – 362. For Accounts 367 through the 371 accounts, for purposes of its studies in this case, Staff utilized Ameren Missouri's classifications. Those classifications, as well as those discussed above, are depicted in the chart below:



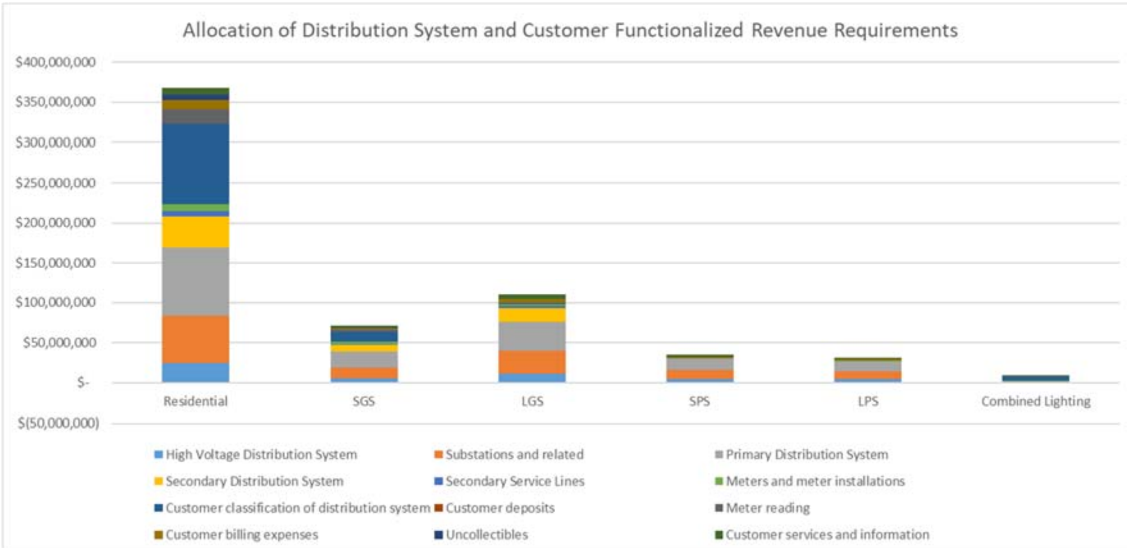
In general, Ameren Missouri was unable to provide information concerning which types of meters, transformers, and other items of distribution equipment were used for serving customers by rate schedule or by service voltage. That information is critical to development of distribution classifications. As depicted in the graph below, based on information provided publicly in File No. EO-2019-0044, the distribution plant account balances will roughly double over the next five years. This means that the information to better classify these accounts will become more critical, and it means that the opportunity exists for Ameren Missouri to record the data associated with these planned expenditures to facilitate future classification studies.



2. Allocation of Distribution Costs and Customer Service and Related Costs

Voltage level is 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, SGS, LGS, and lighting customers are served at secondary voltage; SPS and LPS customers are served at primary voltages. 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. A summary of Staff's allocator use and derivation is provided below.

In several instances Staff relied on Ameren Missouri's allocators for purposes of the Staff study in this case. As referenced above, Staff recommends Ameren Missouri retain and organize information related to the service schedule and voltage level of infrastructure to enable more robust study of these accounts as the net plant balances grow over the planned horizon. The allocations of these costs to the classes are depicted in the graph below.[10]



B. Production and Transmission Related Costs - Assigned Capacity Study

A Service Agreement between Ameren Missouri and MISO was approved by the FERC on March 25, 2004. The MISO IM became operational in 2005. MISO operates markets to ensure that its participants establish resource adequacy. Ameren Missouri's currently owned and operated capacity exceeds its resource adequacy requirements, and Ameren Missouri has committed to develop additional generating resources, which Ameren Missouri represents will be largely related to its intended means of compliance with the Missouri Renewable Energy Standard.

For decades class cost of service studies have relied on the relative capacity demands of the various classes as the most reasonable significant or sole determinant for allocating the embedded cost revenue requirement of the studied utility. This is no longer the most reasonable determinant. Staff recommends collapsing the historic functions of Production Capacity, Production Energy, Production O&M, and Transmission[11] into a single Production and Transmission Function.[12]

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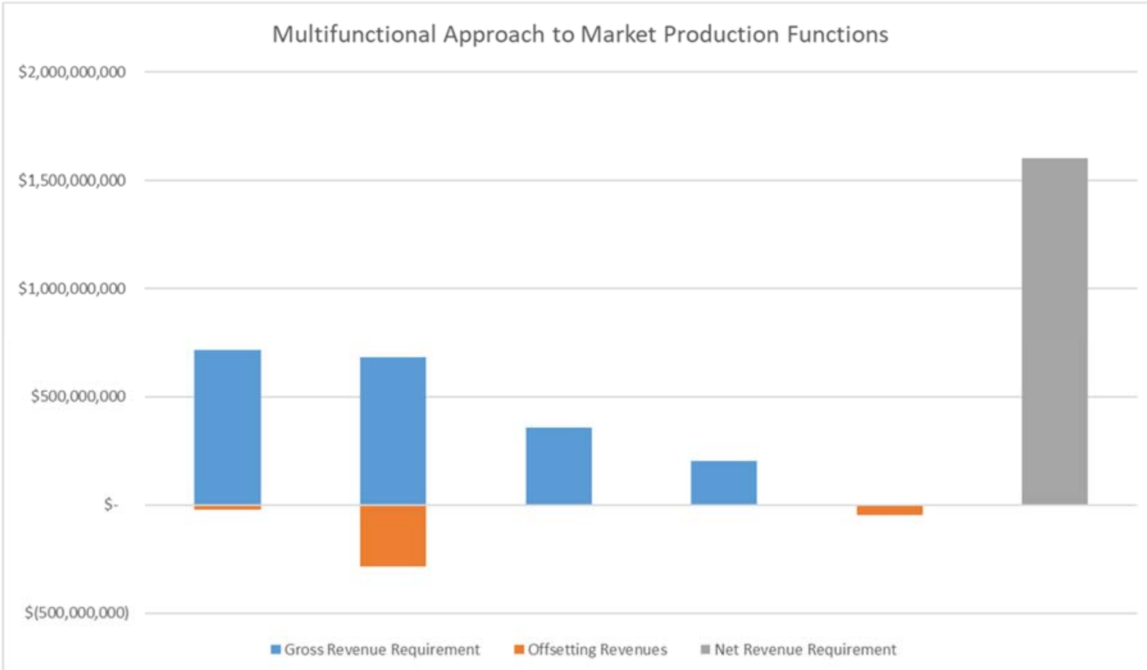
[10] The allocation of several Customer Service related accounts is simplified in this depiction. These accounts do not reflect the allocation or assignment of taxes or the general and miscellaneous accounts that are discussed as assigned to the indicated functionalized classes.

[11] Naming conventions and the precise number of functions used have varied over time.

[12] These accounts do not reflect the allocation or assignment of taxes or the general and miscellaneous accounts that are discussed as assigned to the indicated functionalized classes.



For its recommended Assigned Capacity Study, Version B, Staff determined the value of the capacity to be assigned as the system usage of approximately 7.1 GW, multiplied by a reserve margin of 15.3%, multiplied by the current MISO Cost of New Entry of $756/kW. Staff assigned the resulting net costs and related depreciation expense to the classes based on each classes' maximum usage in the hour of a system coincident peak, or the hour before or after.[13]

Market Production and Transmission Assignments	Amount to be Assigned	Residential	SGS	LGS	SPS	LPS	Combined Lighting
Assigned Capacity Rate Base	$ 3,295,122,079	$ 1,657,621,043	$ 378,811,341	$ 710,860,826	$ 282,775,806	$ 244,952,527	$ 20,100,537
Assigned Capacity Expenses	$ 195,892,657	$ 98,544,389	$ 22,520,064	$ 42,260,169	$ 16,810,820	$ 14,562,253	$ 1,194,963

Staff assigned the approximate $904 million of the cost of energy purchased to serve load to the classes using each class's load-weighted[14] contribution to the total.

Market Production and Transmission Assignments	Amount to be Assigned	Residential	SGS	LGS	SPS	LPS	Combined Lighting
Assigned Energy Expenses	$ 904,991,372	$ 379,915,719	$ 95,545,427	$ 223,341,008	$ 102,113,646	$ 99,568,363	$ 4,507,209

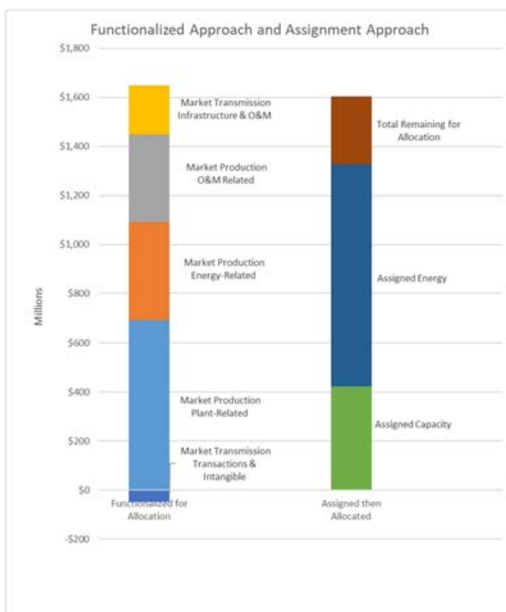
[13] This expansion of use of a single hour is intended to provide some recognition for the load diversity that occurs across the MISO system. The Ameren Missouri CP will not necessarily coincide with the CP of the MISO system – which spans significant distances east to west, north to south, and across time zones. This method also results in some allocation of production costs to the combined lighting class, due to the timing of winter month CPs.

[14] Staff was unable to incorporate the impact of all normalization adjustments, such as the impact of net-metered solar and MEEIA rebasing into the loads used for this purpose. The impact of these adjustments on the assignment is expected to be minimal at this time.

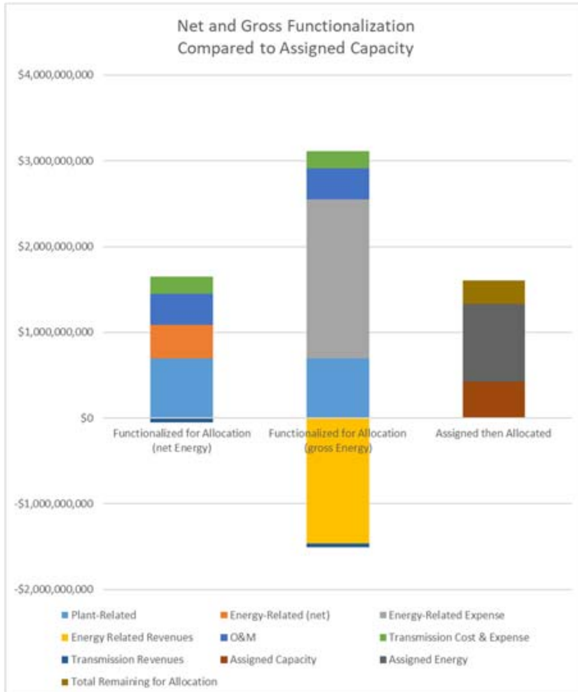
The interaction of these ratebase and expense assignments results in a net market and transmission revenue requirement of approximately $194 million remaining for allocation.

Market Production and Transmission Assignments	Totals	Amount to be Assigned
Market Production and Transmission Rate Base	$ 6,668,943,168	
Assigned Capacity Rate Base		$ 3,295,122,079
Net Market Production and Transmission Rate Base	$ 3,373,821,089	
Market Production and Transmission Expenses	$ 1,141,258,459	
Assigned Capacity Expenses		$ 195,892,657
Assigned Energy Expenses		$ 904,991,372
Net Market Production and Transmission Expenses	$ 40,374,430	
Gross Market Production and Transmission Revenue Requirement	1,602,816,016	
Assigned Market Production and Transmission Revenue Requirement	$ 1,328,939,428	
Net Market and Transmission Revenue Requirement to be allocated	**$ 273,876,588**	

The graph below compares the historic functionalized approach with Staff's assignment approach, which is designed to more reasonably represent a utility's participation in integrated energy markets.[15]

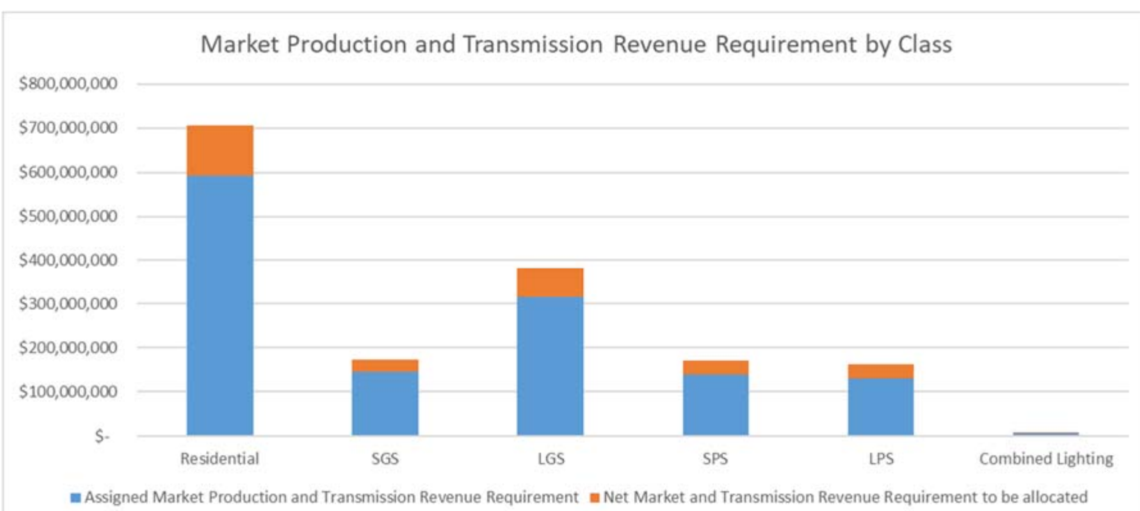


[15] As discussed throughout this section and depicted in these graphs, taxes and general and miscellaneous accounts are excluded from amounts provided, and net energy-related amounts are used unless otherwise noted.



For its primary study, Staff allocated the unassignable remainder based on class energy requirements. The results of this series of assignments and allocations are provided below:

Market Production and Transmission Assignments	Totals	Residential	SGS	LGS	SPS	LPS	Combined Lighting
Net Market Production and Transmission Expenses	$ 40,374,430						
Gross Market Production and Transmission Revenue Requirement	1,602,816,016						
Assigned Market Production and Transmission Revenue Requirement	$ 1,328,939,428	$ 593,184,060	$ 144,283,023	$ 314,799,855	$ 138,495,380	$ 131,083,780	$ 7,093,330
Net Market and Transmission Revenue Requirement to be allocated	**$ 273,876,588**	$ 112,972,744	$ 28,536,890	$ 67,943,116	$ 31,661,988	$ 31,176,211	$ 1,585,639
Market Production and Transmission Revenue Requirement		$ 706,156,804	$ 172,819,914	$ 382,742,970	$ 170,157,368	$ 162,259,991	$ 8,678,968



C. Remaining Functions for Allocation

Staff assigned and allocated costs not only to the studied rate classes, but also to functionalized classes. This facilitates the comparison of the impact of the selected allocators on the study results. Specifically, Staff assigned and allocated costs to the rate classes Residential, Small General Service, Large General Service, Small Primary Service, and a combined Lighting Class, and to the functional classes "Market Production & Transmission," "Taxes," "SB 564," and "General Unassignable for Allocation." The revenue requirements of the functionalized classes were then reallocated to the rate classes, using the allocators indicated for each "version" of study.[16]

Staff compared a variety of allocation methods such as sales at generation, revenue related, and composite taxes concerning these functionalized class revenue requirements.

The typical allocation of the accounts functionalized into these categories is highly subjective. For example, the revenue requirement of the employee cafeteria at the Ameren General Office Building is not reasonably related to any determinate typically used in a CCOS. On the other hand, the property taxes associated with utility plant in a given county are readily determinable, but Ameren Missouri's record keeping does not facilitate matching that property tax level to the portion of its mass-asset recorded plant and reserve with which it is associated, nor with the class to which that plant and reserve was allocated.[17] Therefore, for simplicity and to minimize impact on similarly situated customers in different classes, at this time for its recommended study, Staff has allocated the functionalized classes to the rate classes on the basis of class sale at generation. Alternative allocators are discussed in the CCOS Results section.

D. CCOS Results and Interclass Cost Responsibility Recommendations

1. Study Results

Staff performed multiple versions of its CCOS Study by reallocating the functionalized classes described above. The allocators used, by version, are described below:

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[16] As discussed above, the Market Production & Transmission functional class was reassigned separately as rate base and expense to the extent possible.

[17] This is not intended to imply that this exercise would be worth the time and effort associated with such a calculation if the data were available to do so.

Assigned Capacity - Version B	Rate Base Allocator	Expense Allocator
Assigned Capacity	Max CP w Adjacent Usage	Max CP w Adjacent Usage
Assigned Energy	Market weighted energy	Market weighted energy
Net Market Production and Transmission	Sales at Generation	Sales at Generation
Taxes	Sales at Generation	Sales at Generation
SB 564	Sales at Generation	Sales at Generation
General Unassignable for Allocation	Sales at Generation	Sales at Generation
Assigned Capacity - Version A	Rate Base Allocator	Expense Allocator
Assigned Capacity	Max CP w Adjacent Usage	Max CP w Adjacent Usage
Assigned Energy	Market weighted energy	Market weighted energy
Net Market Production and Transmission	Sales at Generation	Sales at Generation
Taxes	Gross Plant	Composite Tax
SB 564	Sales at Meter	Sales at Meter
General Unassignable for Allocation	Sales at Generation	Sales at Generation

A&E 4NCP - Version A	Rate Base Allocator	Expense Allocator
Capacity	A&E 4 NCP	A&E 4 NCP
Energy	Sales at Generation	Sales at Generation
Taxes	Gross Plant	Composite Tax
SB 564	Gross Plant	Gross Plant
General Unassignable for Allocation	Gross Plant	Gross Plant
A&E 4NCP - Version A	Rate Base Allocator	Expense Allocator
Capacity	A&E 4 NCP	A&E 4 NCP
Energy	Sales at Generation	Sales at Generation
Taxes	Sales at Generation	Sales at Generation
SB 564	Sales at Generation	Sales at Generation
General Unassignable for Allocation	Sales at Generation	Sales at Generation

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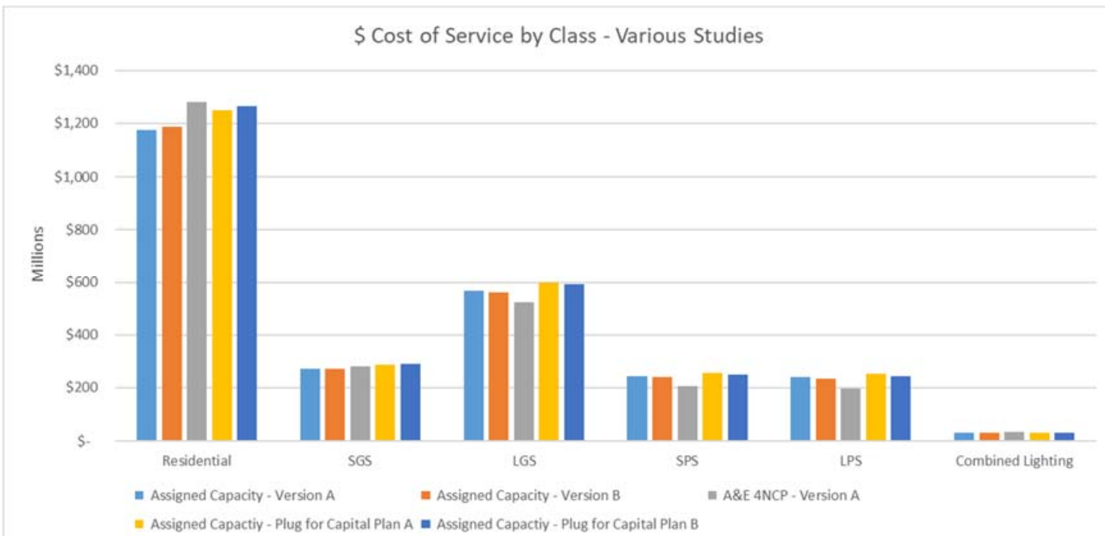
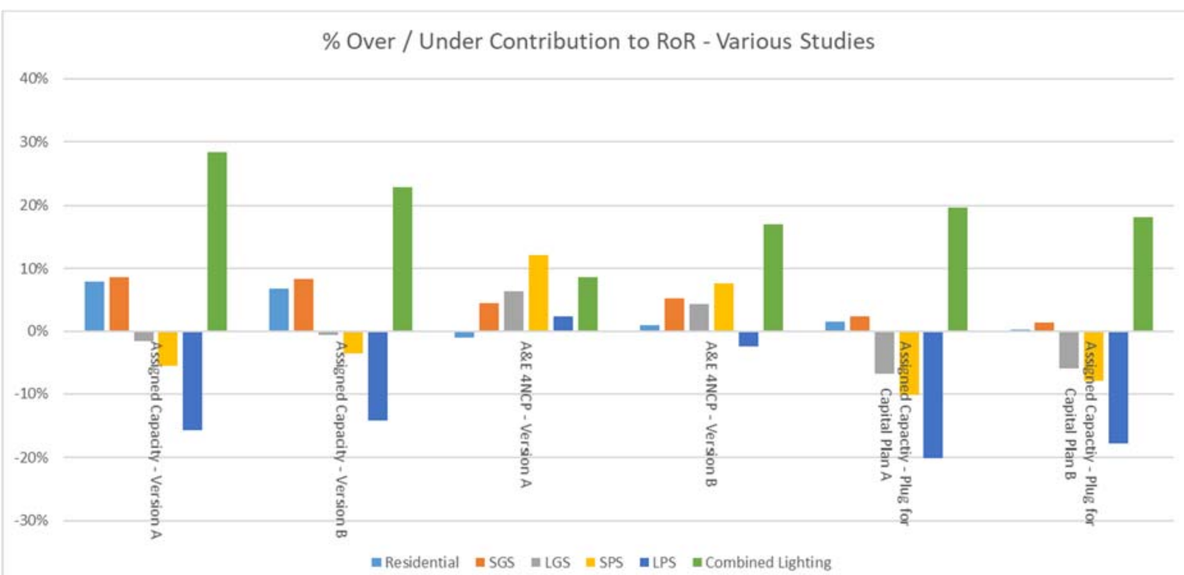
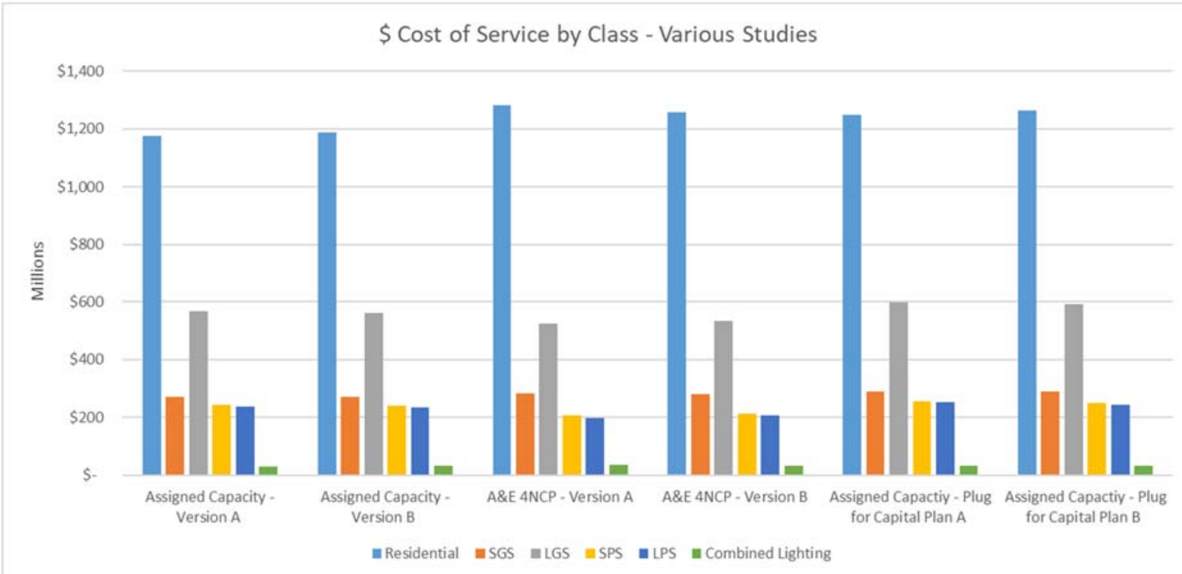
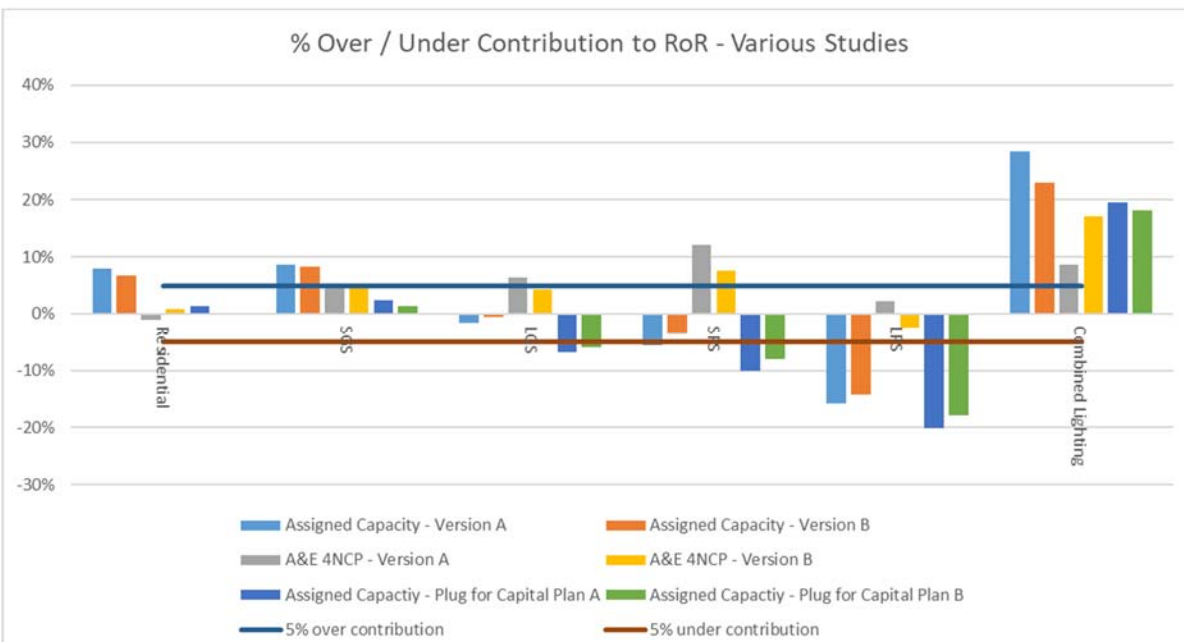
Assigned Capactiy - Plug for Capital Plan A	Rate Base Allocator	Expense Allocator	Projected Distribution & Meters
Assigned Capacity	Max CP w Adjacent Usage	Max CP w Adjacent Usage	
Assigned Energy	Market weighted energy	Market weighted energy	
Net Market Production and Transmission	Sales at Generation	Sales at Generation	
Taxes	Sales at Generation	Sales at Generation	
SB 564	Sales at Generation	Sales at Generation	Sales at Generation
General Unassignable for Allocation	Sales at Generation	Sales at Generation	
Assigned Capactiy - Plug for Capital Plan B	Rate Base Allocator	Expense Allocator	
Assigned Capacity	Max CP w Adjacent Usage	Max CP w Adjacent Usage	
Assigned Energy	Market weighted energy	Market weighted energy	
Net Market Production and Transmission	Sales at Generation	Sales at Generation	
Taxes	Sales at Generation	Sales at Generation	
SB 564	Sales at Generation	Sales at Generation	Meters & Distribution Primary
General Unassignable for Allocation	Sales at Generation	Sales at Generation	









2. Interaction of Tariffed Rates and Temporary Tax Rider

Pursuant to tariff sheets promulgated in File No. ER-2018-0362, each Ameren Missouri customer currently experiences a bill discount per kWh from existing rates of the amounts indicated below:

	Temporary Tax Rider	Temporary Tax Rider
	$/kWh	% of Class Revenue
Residential	$ 0.00621	6.05%
SGS	$ 0.00581	6.06%
LGS	$ 0.00462	6.06%
SPS	$ 0.00404	6.11%
LPS	$ 0.00348	6.09%

For purposes of comparison, were the Commission to order an equal 2.5% decrease to all classes, and apply the decrease to the energy charges within a class evenly, the resulting decreases per kWh would be quantified approximately as provided below:

	Temporary Tax Rider	2.5% equal decrease to all rate classes, applied to energy charges only*
	$/kWh	$/kWh
Residential	$ 0.00621	$ 0.00257
SGS	$ 0.00581	$ 0.00240
LGS	$ 0.00462	$ 0.00191
SPS	$ 0.00404	$ 0.00165
LPS	$ 0.00348	$ 0.00143

*Staff recommends Residential reduction be applied to first blocks of energy charge only. Staff recommends non-residential reductions be applied to demand charges only.

In other words, prior to any rate design changes that will result in differences in revenue responsibility among customers within a class, the rate decrease recommended by Staff will reduce class revenues by approximately 2.5% per class; the existing temporary tax rider reduces class revenues by an average of approximately 6.1% per class. Customers will therefore experience this reduction in Ameren Missouri's revenue requirement, net of the elimination of the temporary tax rider, as an increase of approximately 3.6%, prior to changes in rate design that will impact customer bills. Example Residential Customer bill calculations are provided below, at various levels of usage, by season:[18]

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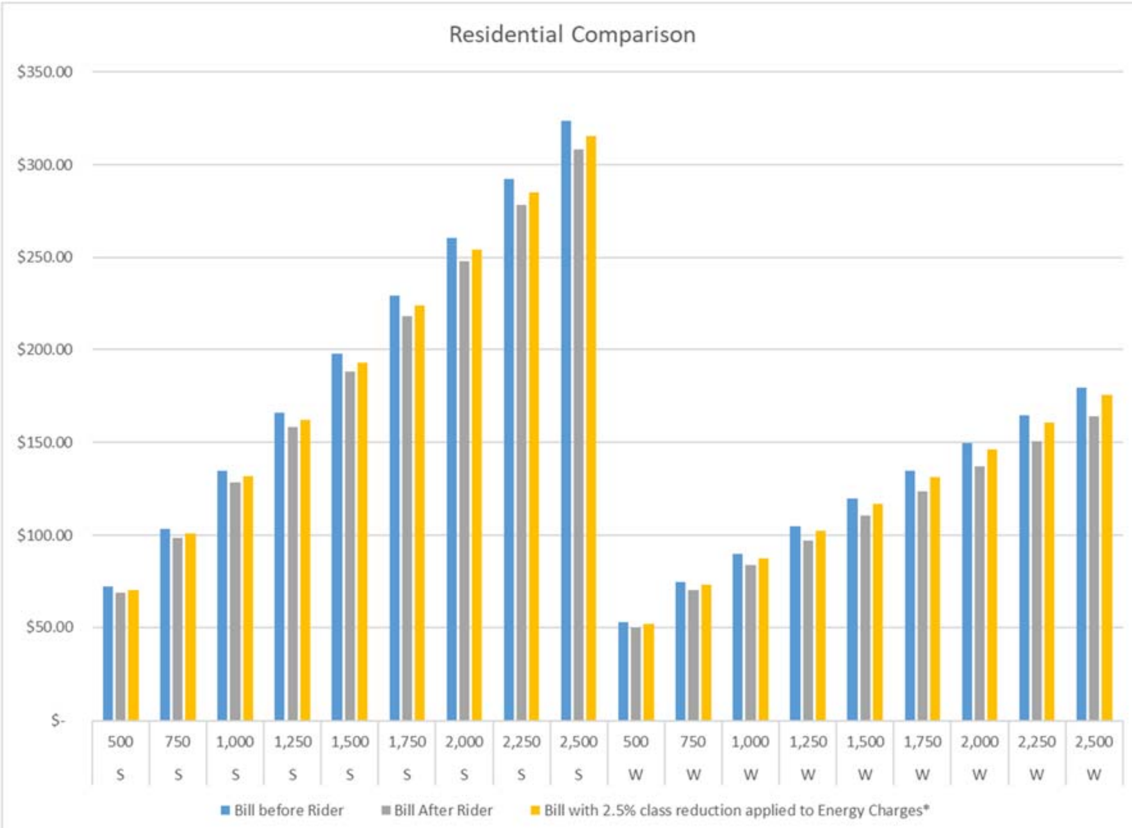
[18] Staff recommends Residential reduction be applied to first blocks of energy charge only. Staff recommends non-residential reductions be applied to demand charges only. Customer charge is included, but FAC, MEEIA and RESRAM are not reflected in these bill calculations.



3. Recommendations

Staff recommends modernizing the allocation of the revenue requirement associated with Ameren Missouri's participation in the MISO IM by moving to the capacity assignment method discussed in the preceding sections. One drawback of any method of allocation that relies on coincident peak is the potential freeridership of lighting classes, for this reason Staff conducted the 4NCP A&E studies referenced above.[19] Staff will continue to investigate and refine this approach with the intent to apply it to all Missouri-regulated utilities as warranted by the facts and circumstances surrounding each utility's level of market participation and capacity position.

Overall, Staff concludes that given Ameren Missouri's participation in the MISO Integrated Market, its current tax position, the legislative causation of the spending occurring

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[19] A&E studies are less reliable than Staff's BIP, however, much less data and time is required to conduct an A&E study than Staff's BIP; therefore Staff used the 4NCP A&E allocator for this comparison study rather than a detailed BIP. Staff applied the A&E in a manner most beneficial to high load factor classes for purposes of this comparison study as it relates to revenues from energy sales.

pursuant to SB 564, Ameren Missouri's assertions that its capacity build-out is related to its intended means of compliance with the Missouri Renewable Energy Standard, and the lack of a definitively reasonable allocation method for the elements of the General Unassignable functionalization, Staff recommends reliance on its "Assigned Capacity – Version B." However, as a whole and incorporating the results of the studies that reflect a plug for Ameren Missouri's anticipated 5 Year Capital Plan, the CCOS studies indicate that the most reasonable course of action is to moderate the interclass shifts indicated by the Assigned Capacity – Version B study, and instead implement the reduction in revenue requirement on an equal percentage basis, relative to current tariff rates, and irrespective of the temporary tax rider.

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

III. Rate Design

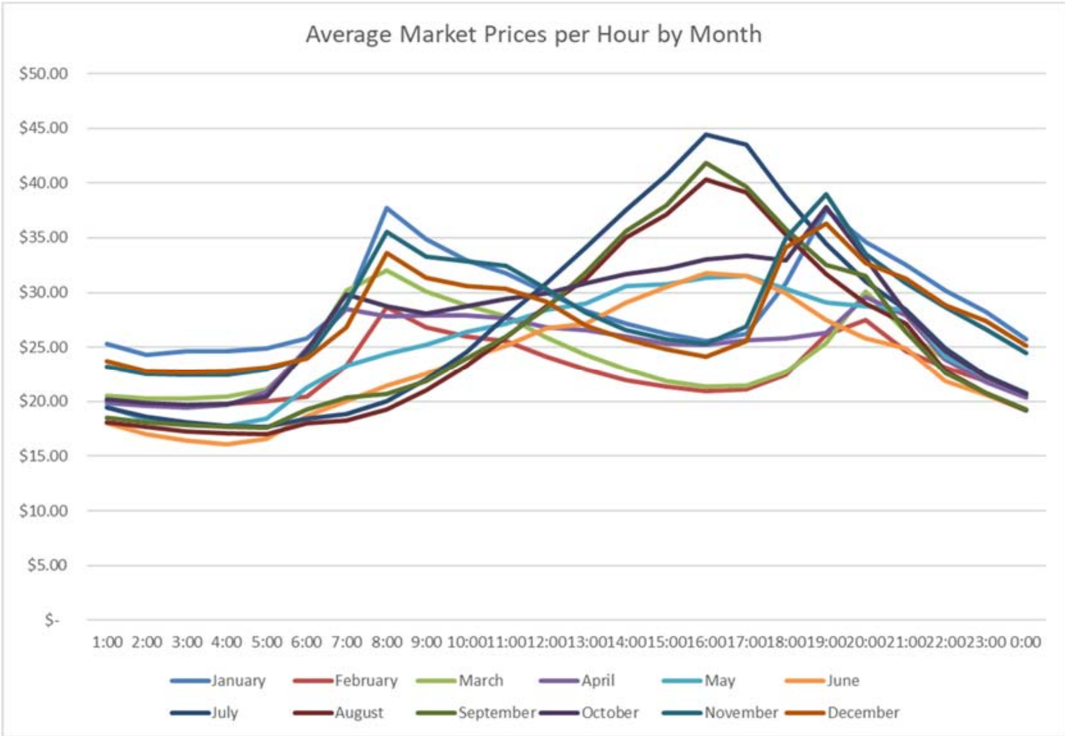
A. Residential Time of Use

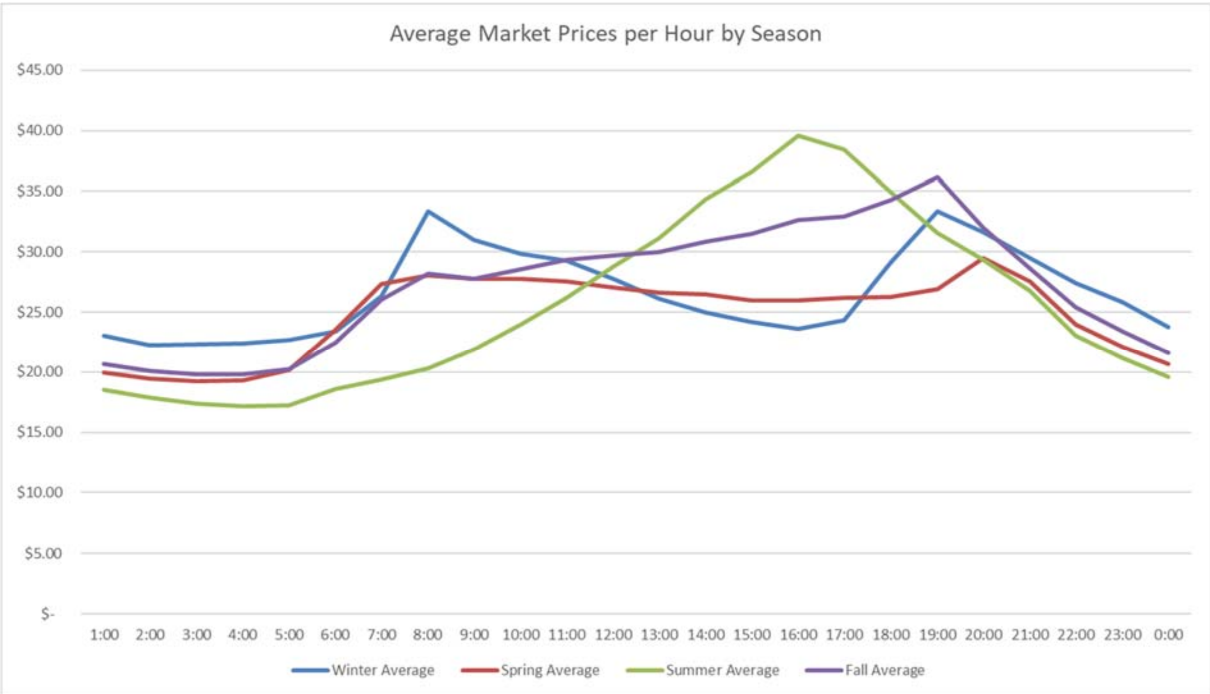
Considerations in defining reasonable bounds for a ToU rate design include: (1) the cost of energy across time; (2) the cost of system transmission and distribution capacity, and identification of the times driving those costs; (3) the cost of production or RTO capacity, and identification of the times driving those costs; (4) understandability of rates to all impacted customers; and (5) for purposes of this initial case, mitigation of rate impacts to all impacted customers in recognition of the intent of these rates as customer education. In the interest of understandability, impact mitigation, and in recognition of the unfamiliarity of customers with ToU rates, Staff selected a relatively long on-peak period as the basis for its recommended ToU rates. This enables consistency of the on-peak definition across the year and across classes, and lays the groundwork for future implementation of seasonally-appropriate super-peak rates and super-off-peak discounts.

The ToU rates designed and studied below are based on Ameren Missouri's residential revenue recovery embedded in current rates, including the current residential customer charges. Any changes to class revenue responsibility and customer charges would necessarily be incorporated in the rates resulting from this case. Decreases to class revenue responsibility and increases to customer charges would tend to decrease the rate impact of a switch to ToU rates.

1. Energy Cost Considerations

The average price of energy to serve Ameren Missouri's load varies by time of day and by time of year. This variability is summarized in the graphs below, by month and by season:



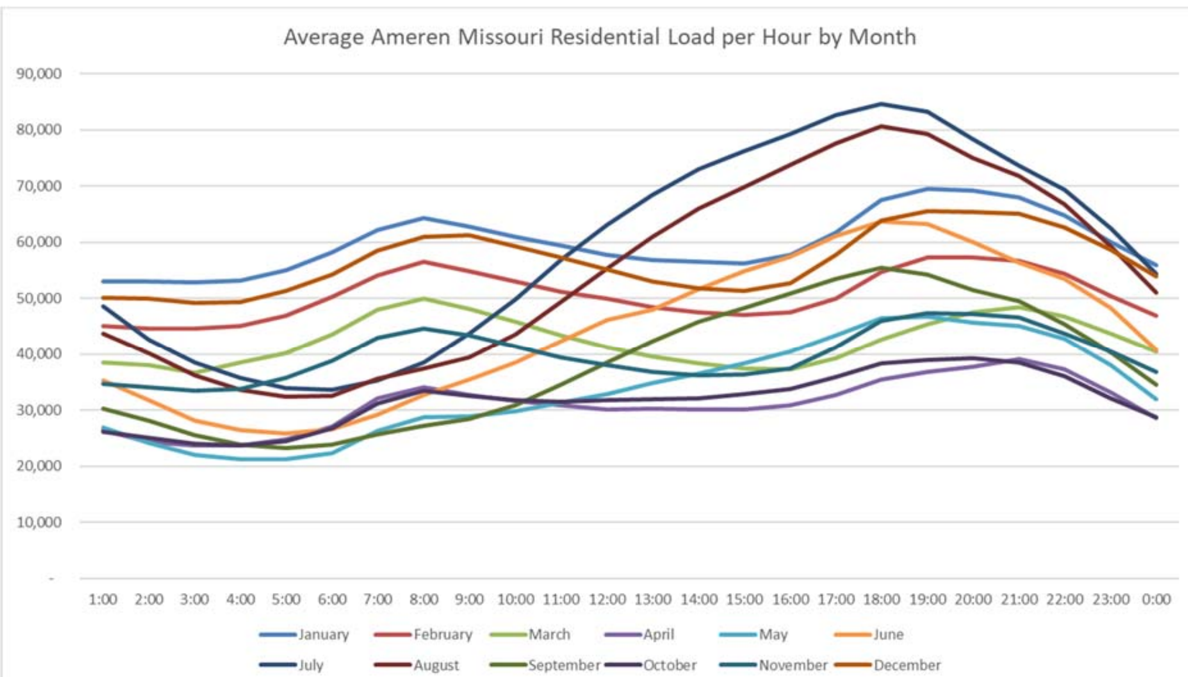


Energy costs demonstrate that the highest valued energy is the energy used during summer late afternoon and early evening hours.[20] This also demonstrates that fall and winter late evening hour energy is high-valued, and that a peak is experienced during winter mornings.

2. Distribution System Considerations

Staff also reviewed system utilization across hours of the day, at both the residential class and system levels to determine hours of the day associated with fuller utilization of the distribution system and local elements of the transmission system.

The graphs below demonstrate the average residential load and total system load by hour and month, and by hour and season:



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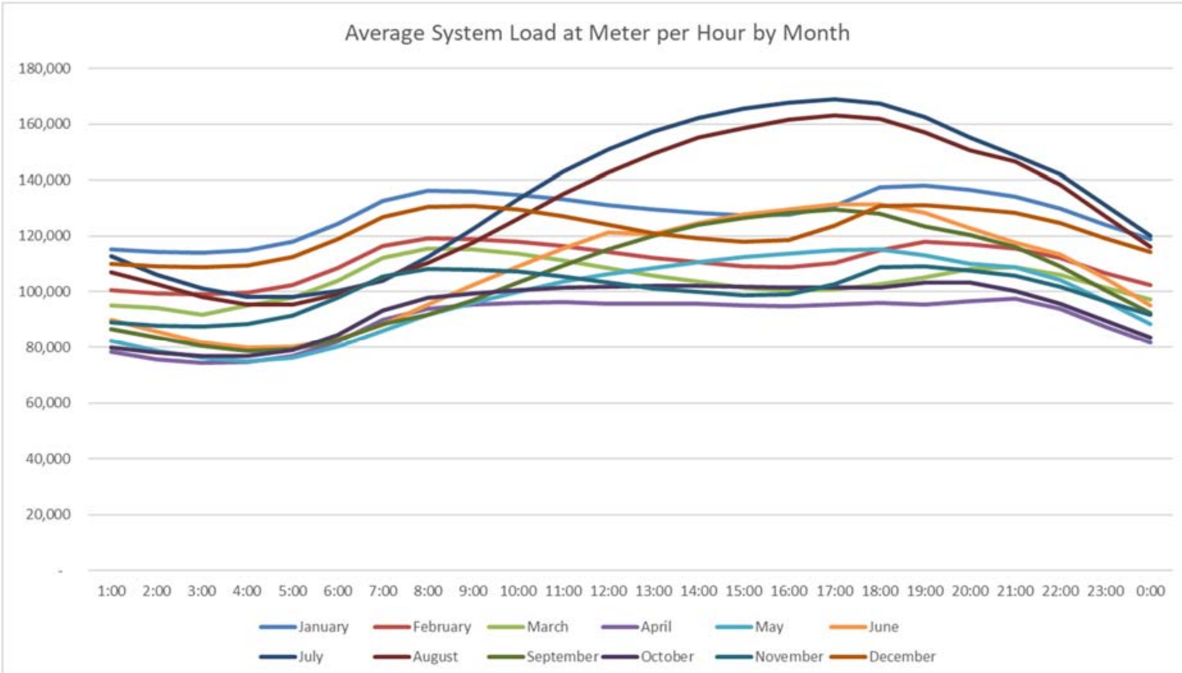
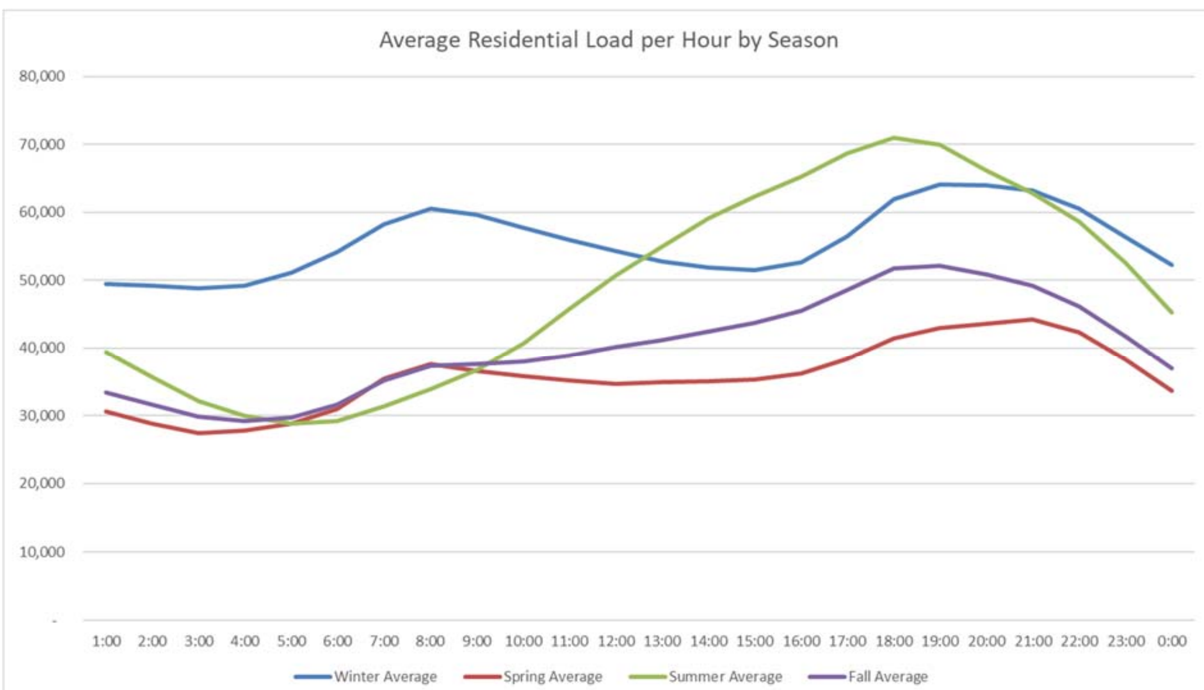
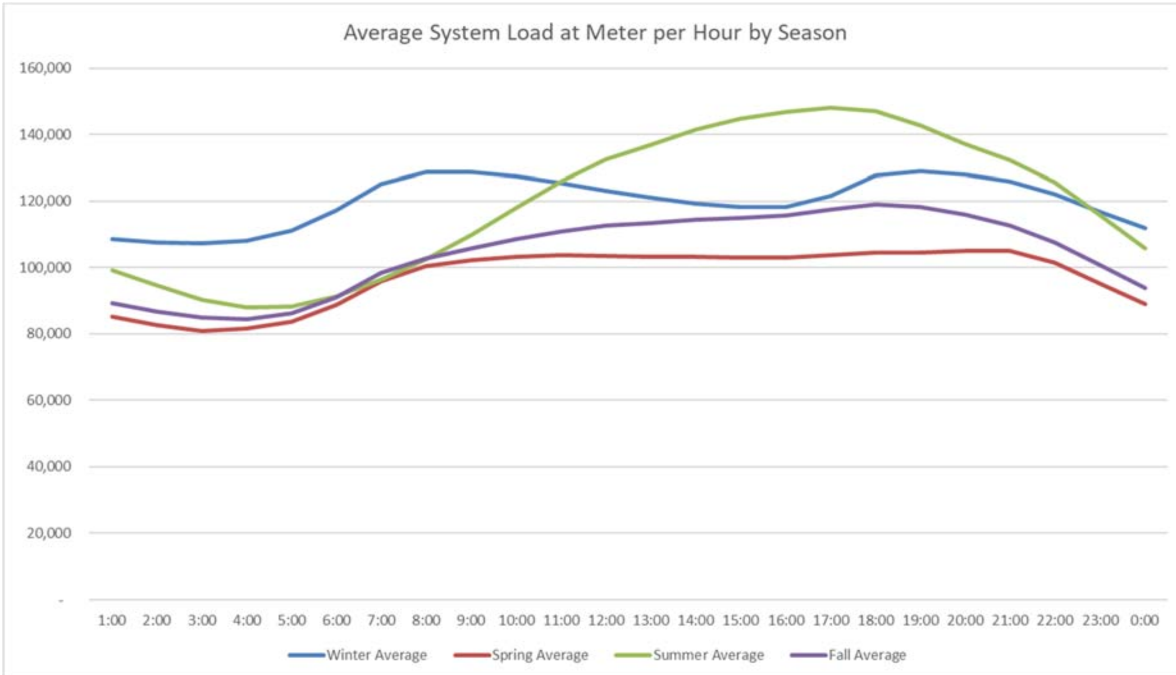
[20] This is also the time associated with MISO peaks used for resource adequacy purposes.


Average System Load at Meter per Hour by Month
180,000
160,000
140,000
120,000
100,000
80,000
60,000
40,000
20,000
-
1:00 2:00 3:00 4:00 5:00 6:00 7:00 8:00 9:00 10:00 11:00 12:00 13:00 14:00 15:00 16:00 17:00 18:00 19:00 20:00 21:00 22:00 23:00 0:00
January
February
March
April
May
June
July
August
September
October
November
December


Average Residential Load per Hour by Season
80,000
70,000
60,000
50,000
40,000
30,000
20,000
10,000
-
1:00 2:00 3:00 4:00 5:00 6:00 7:00 8:00 9:00 10:00 11:00 12:00 13:00 14:00 15:00 16:00 17:00 18:00 19:00 20:00 21:00 22:00 23:00 0:00
Winter Average
Spring Average
Summer Average
Fall Average



The graphed loads indicate that the time of the most usage is summer late afternoon and evening, with nearly dual winter peaks in morning and late evening. While a small peak occurs in spring mornings and fall evenings, usage is less variable in spring and fall months than summer and winter months. When total system load is compared to residential load, the daytime hours are significantly smoothed.

3. ToU Rate Design

In selecting on peak and off peak periods for a time of use rate design, price signals should be sent that reflect that system costs are driven by times of high system utilization. Price signals should not be sent to increase use of the system during times of high system utilization. Selection of reasonable on-peak and off-peak time periods is complicated by two factors, (1) utilization patterns vary by season, and (2) the residential class itself has a different utilization pattern than the total system. In the interest of having one pricing period in place throughout the year, and in the interest of not incenting the residential class to consume additional energy during times when residential class utilization is not high, but total system utilization is high, it is most reasonable for this initial implementation of ToU rates to utilize a longer on-peak period that (1) encompasses the times of high system utilization across various seasons and (2) encompasses high levels of system utilization by both the residential class and the total system.

i. Understandability and Customer Impact Mitigation

At this time, based on rate impact mitigation and energy-cost drivers, Staff recommends the on-peak period be defined as beginning at 9:00 am and ending at 8:59 pm, in all months.

In the Staff Report on Distributed Energy Resources, filed April 5, 2018, in File No. EW-2017-0245, concerning residential and utility-wide rate design, Staff recommended the following:

> *Initial steps to be taken during or prior to applicable rate cases:*
> a. Residential Rate Design:
> i. Improve customer education regarding cost composition and energy cost differences over time of day and season.
> ii. Review rates on an unbundled basis, with potential to provide tariffed rates on an unbundled basis.
> iii. Implement a Low-differential TOU rate design related only to energy price difference or existing rate design blocks, with relatively long on-peak periods.
> iv. Study determinants for an on-peak demand charge.
>
> c. Utility-wide
> i. Study bifurcating Fuel and Purchased Power costs into the TOU time periods for recovery of differences through bifurcated FACs.
> ii. Study distribution of DER on existing system.
> iii. Identify locations on the distribution and transmission systems where DER may be an alternative to expansion or replacement of the system.
> iv. Develop strategies to encourage strategic placement and deployment of DER to reduce overall system investment needs and operation expenses, including transmission congestion including study of locational rate designs and location-dependent compensation schemes.
> v. Study located DER scenarios as part of Chapter 22 planning consistent with Staff's recommendations contained in *Section VII. Changes to IRP process or Chapter 22*.
> vi. Study energy cost distribution and system utilization to find opportunities for efficient utilization and pricing – for example, some utilities experience significant winter night and evening usage – to refine time periods applicable to time of use rates and develop super on-peak or super off-peak rates.
>
> *Phase 2 (approximately 2025 time frame, will vary by utility and rate case timing):*
> a. Residential:
> i. Continued and increased customer education regarding cost composition and energy cost differences over time of day and season.
> ii. Increase TOU differential to recover some generation capacity costs on-peak.
> iii. Incorporate super on-peak and super off-peak TOU elements, which may vary by season.

iv. Implement a 12 month demand charge for recovery associated with local distribution facilities.

c. Utility-wide

i. Study distribution locational pricing determinants for locational rate designs; study location-dependent compensation schemes.

ii. Revenue Decoupling.

iii. Based on outcomes of studies of beneficial DER location, locate DER or incent the location of DER using reasonably designed compensation designs.

Anticipated goals (approximately 2030 time frame, will vary by utility and rate case timing):

a. Residential:

i. Continued and increased customer education regarding cost composition and energy cost differences over time of day and season.

ii. Implement on-peak demand charge to nearly fully recover generation capacity costs on peak, not already included in on-peak and super on-peak elements.

iii. Consider and implement, if appropriate, distribution locational rates or rate elements.

c. Utility-wide

i. Study distribution locational pricing determinants.

ii. Based on outcomes of studies of beneficial DER location, locate DER or incent the location of DER using reasonably designed compensation designs.

A low-impact, low-differential, long time period time-of-use rate design is an excellent customer education opportunity. As provided below, Staff's rate design recommendation is intended to produce little to no bill variation to customers. However, this rate design will impart to customers the concept that, in general, energy used during the daytime is more cost-intensive, and energy used during the night time is less cost-intensive.

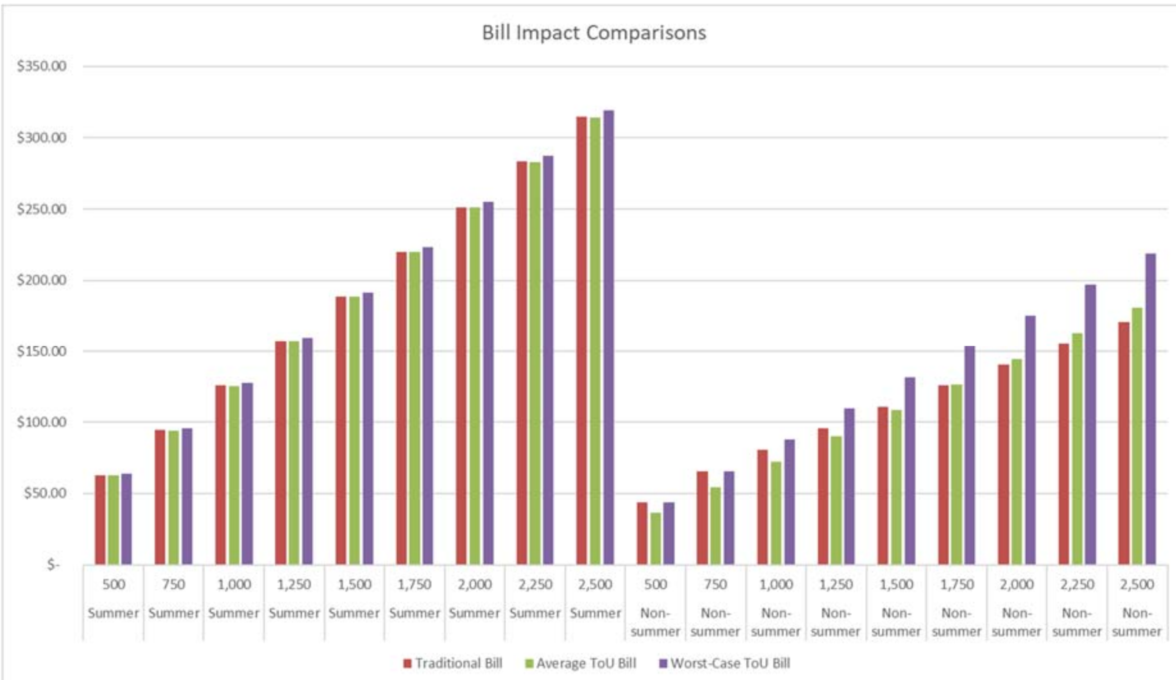
ii. ToU Rates and Bill Impacts

Staff's proposed ToU rate design, on a revenue neutral basis, designed based on current customer charges is provided below[21]:

	Off Peak	On Peak
Summer	$ 0.1245	$ 0.1277
Non-summer	$ 0.0600	$ 0.0876

[21] These bill calculations do not include the customer charge, MEEIA, FAC, or RESRAM.

These rates will be subject to change based on the overall revenue to be collected from Ameren Missouri's residential class, and subject to any change in the residential customer charge.[22] The estimated impact of this design is depicted below across a range of monthly kWh consumptions:



The intent of this ToU design is to establish a "Time of Use Training Wheel" framework that is consistent across the year, but upon which more complex elements that will vary by season can be established. For example, in future cases, it is likely that Staff will recommend implementation of:

(1) an additional summer on-peak charge priced consistent with pricing signals associated with RTO capacity costs or production capacity costs, for example, an additional approximate $0.02-5 / kWh during summer afternoon hours of approximately 2:00 pm – 6:00 pm; and

(2) an additional spring/fall (and possibly summer) super-off-peak charge associated with times of very low energy prices and capacity costs, for example, a discount of approximately $0.02-5 / kWh during shoulder months during approximately the hours of 11:00 pm – 5:00 am.

[22] Any increase in customer charge would tend to decrease these energy rates in a manner that is generally consistent with mitigating customer impact to above-average use customers.

Rate elements to encourage pre-cooling thermal storage during the summer mornings or system-coincident demand charges to recover capacity costs associated with summer afternoons are also possibilities that, while ideal from a pure cost-recovery perspective, cannot be expected to be understandable to customers at this time.

iii. ToU Implementation

Because Ameren will not complete deployment of AMI meters for some time, and in the interest of using these introductory ToU rates to educate customers about ToU with minimal customer impact, Staff's recommended ToU design focused on minimizing customer impact, and applying a gradual rollout of the rates. Specifically, Staff recommends that when a customer's AMI meter is installed, the customer begins receiving a "shadow bill" indicating the usage in each interval, and what the customer's energy charges would have been on the Staff-designed ToU rate. Then, approximately 6 months to 1 year after the AMI installation, Staff recommends that Ameren Missouri interact directly with that customer to educate the customer as to what that customer's bill would have been during the prior period on the recommended default ToU rate schedule, as well as any of the alternative Ameren ToU schedules that may be approved at that time. Staff recommends that for new customers or new accounts, if an AMI is in place at that premise, that new customers be placed on the default ToU rate schedule unless they specifically request otherwise.

Staff Expert/Witness: Sarah L.K. Lange

iv. ToU Pilot Costs and Tracker

For its proposed TOU pilot program, Ameren Missouri anticipates incurring costs for conducting focus groups, recruiting and retaining participants, developing educational materials, developing tools to communicate usage information back to participants, conducting participant surveys, and analyzing and reporting results of participant load impacts. Ameren Missouri estimates that the costs incurred will be $1 million per year. Ameren Missouri proposes to include an annual amount of $1 million in base rates each year for a two year period. In addition, Ameren Missouri recommends use of a one-way tracker for TOU pilot program costs during this two year period.[23]

[23] Case No. ER-2019-0335 Steven M. Wills Direct Testimony, pages 61- 62.

Staff is opposed to inclusion of an estimated annual amount in base rates for the pilot program costs in this proceeding. Instead, Staff recommends that Ameren Missouri defer, beginning with the effective date of rates in this current rate proceeding, the TOU pilot program costs that include but are not limited to marketing, education, evaluations and administration costs, for potential recovery of prudently incurred costs in a subsequent general rate case through an amortization. Staff's recommendation is consistent with the terms of the Stipulation and Agreement[24] approved by the Commission on October 31, 2018 for Kansas City Power & Light Company and KCPL Greater Missouri Operations Company in their last general rate cases, Case Nos. ER-2018-0145 and ER-2018-0146.[25]

Staff Expert/Witness: Karen Lyons

B. Residential General Service

Staff recommends that any decreases ordered in this case for the residential general service class be applied to the first energy blocks for both summer and winter. This will result in a slight incline design for the summer, and a reduction of the decline design for the winter. The approximate rates under this design are provided below:

	Current		Staff Recommended	
Summer first 750	$	0.12580	$	0.11992
Summer over 750	$	0.12580	$	0.12580
Winter first 750	$	0.08760	$	0.08387
Winter over 750	$	0.06000	$	0.06000

The approximate bill impact, compared to existing bills without the temporary tax rider, existing bills with the temporary tax rider, and bills with an equal percent adjustment to the energy charges are provided below:[26]

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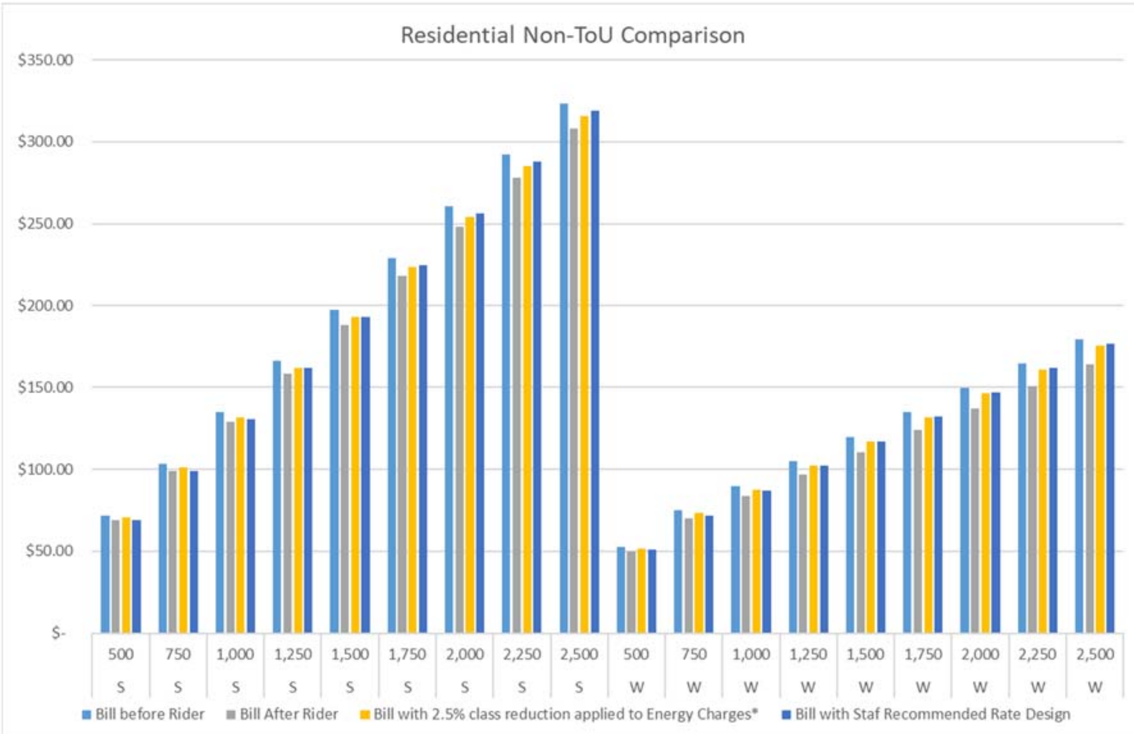
[24] Case No. ER-2018-0145 and ER-2018-0146, *Non-Unanimous Partial Stipulation and Agreement concerning Rate Design Issues*, approved October 31, 2018.

[25] Kansas City Power & Light Company is now known as Evergy Missouri Metro and KCPL Greater Missouri Operations is now known as Evergy Missouri West.

[26] This includes customer charge, but not FAC, MEEIA and RESRAM charges.



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

C. Non Residential Rate Design

Pursuant to the Commission Approved Unanimous Stipulation and Agreement in ER-2016-0179, Ameren Missouri's non-residential demand-related rates were increased disproportionately to the non-residential energy rates. Staff recommends that any decreases ordered for non-residential non-lighting classes in this case be applied to the demand-related rates.

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

IV. Tariff and Other Recommendations

A. Paperless Billing

In an effort to increase customer participation in paperless billing, Ameren Missouri is proposing a $0.50 credit incentive per bill to each new enrollee in Ameren Missouri's paperless billing program. The proposed $0.50 incentive, over a one-year period, will total $6.00 for each new paperless billing enrollee. Existing paperless billing participants will not qualify for the incentive.

According to Ameren Missouri, the total cost of issuing a paper bill per customer is $0.4707 and approximately $0.007 for paperless.[27] The $0.04 difference between the incentive offered ($0.50) and the Company's savings per customer ($0.46) would be absorbed by the Company.[28] The incentive is intended to reasonably approximate the amount of cost savings resulting from customers converting from a paper bill to paperless billing. Ameren Missouri is not seeking recovery in rates in this proceeding of the cost associated with the bill credit incentives. Given no customers will bear the cost of the incentives, Ameren Missouri's request is that the Commission approve the tariff[29] change as filed to initiate the incentives.

Staff is opposed to Ameren's paperless billing credit proposal and will address this issue as part of its rebuttal testimony scheduled to be filed on January 21, 2020.

Staff Experts/Witnesses: Contessa King, Karen Lyons

B. Ameren Missouri's Application of "Billing Period"

Ameren Missouri has 21 billing cycles. Customers are distributed amongst the billing cycles so that not all customers' meters are read and billed on the same day. For example, 50,000 residential customers' meters may be read in the first billing cycle on the first day of the month and another 55,000 residential customers' meters may be read in the second billing cycle on the second day of the month. The use of billing cycles allow for customers to be billed throughout the month instead of all at one time. Ameren Missouri also uses a three-day billing window, which means the Company has three days to read all the meters in a billing cycle.

Staff found that Ameren Missouri's current billing cycles have been staggered over the years to avoid meters being read on weekends and holidays to the point where customers are receiving their appropriate billing month bill before the first of the billing month. For example, in 2019 customers in the first billing cycle for the billing month of October 2019, could have had their meter read as early as September 24, 2019 or as late as September 26, 2019. All customers in the first billing cycle would have received their October bill no later than September 30, 2019. Since a billing cycle, on average, includes 30 days of usage, these customer's bills would have included some usage that occurred in August 2019. However, because it is the customer's October

[27] ER-2019-0335, Direct Testimony of Mark C. Birk, p. 4.
[28] ER-2019-0335, Direct Testimony of Mark C. Birk, p. 4-5.
[29] 3rd Revised Tariff Sheet No. 63.

bill all the usage on the bill, including the customer's usage that occurred in August, would be charged a winter rate. This is problematic in that it mutes the price signals sent by seasonal pricing. For example, customers will be billed for "summer usage" for usage occurring in April, and "winter usage" for usage occurring in August. This does not align cost causation with revenue responsibility, and does not send appropriate price signals to customers regarding the differential cost of energy from a high-cost summer month and a low-cost shoulder month.

As AMI technology and compatible billing systems are deployed, Ameren Missouri could update its tariffs and use end-of-month calendar reads to accurately prorate the rates in effect – by calendar month – on each customer's bill.[30] In the meantime, to align a customer's bill with the appropriate billing month, Staff recommends that Ameren Missouri adjust its billing cycle read dates so that no customer's meter is read prior to the first day of the customer's appropriate billing month and no later than three days before the end of the billing month. Lastly, Staff recommends that Ameren Missouri read each customer's meter on the same day each month. The revenue impact associated with these updated billing determinants should be incorporated through the true-up revenue adjustment.

C. Staff recommends a number of data retention measures be implemented

1. Tracking meter installations by service classification and voltage level;

Staff recommends the Commission order Ameren Missouri to track meter installations by service classification and by voltage level, and integrate the ability to identify the general characteristics of the premise meter within its customer information systems to be deployed to utilize AMI metering. For example, Ameren Missouri is currently unable to identify which meters are utilized by customers in which classes.[31] The difference in the costs of meters capable of handling higher voltages from a typical residential or SGS meter are significant. Apportioning the cost of meters among classes will become more important with the $245 million in additional capital due to the "Smart Meter" program announced in File No. EO-2019-0044.

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[30] This would also facilitate the use of shoulder rates to more accurately reflect the disparity in cost-causation between peak-winter months of December, January, and February, and the shoulder months that are currently included in the "winter" billing season.

[31] See response to Staff Data Request No. 0244, attached as Schedule SLKL-d2.

2. Implement more thorough record keeping or data accessibility practices to better associate distribution system costs with the voltage of energy distributed;

Ameren Missouri has announced approximately $4.6 billion in planned infrastructure spending in File No. EO-2019-0044. Staff recommends that Ameren Missouri develop tracking systems to assign the associated plant balances to distribution classifications high voltage, substation, primary, and secondary, as appropriate. Staff further recommends that Ameren Missouri take steps to identify the portions of the primary distribution system that are used to serve primary customers only, and do not provide service or redundant interconnection to the secondary system.

3. Take steps necessary in its AMI deployment process to provide accurate load research data at a high level of precision, by implementing practices to leverage AMI meter data for load research purposes;

Staff is aware of other utilities that have deployed AMI and have deployed new customer information systems in a manner that does not facilitate the collection of interval data by class or by customer aggregations. Staff recommends that Ameren Missouri include elements in its customer information systems to leverage AMI meter data with customer data – such as voltage, rate schedule, applicable rider B adjustments, net metering customer, etc, in order to produce accurate load research data in a variety of configurations when sufficient AMI meters have been deployed. Class-level or sub-class level hourly load information is necessary for weather normalization studies, and to produce class-level coincident and non-coincident peak information which is used for allocations, among other things.

4. On an ongoing basis, Ameren Missouri should retain interval data for customers with AMI meters be retained for a minimum of a rolling 12 month time period so that customers may compare ToU options;

Staff has recommended implementation of a low-differential residential ToU rate in this case. Ameren Missouri has requested approval of a variety of time-varying rates.[32] To facilitate customer selection of rate options, Staff recommends that Ameren Missouri retain the data necessary to develop a minimum of the 12 most recent months' comparison bills. Until the point that a full 12 months of data becoming available, Ameren Missouri should facilitate the number

[32] Staff will address Ameren Missouri's requested ToU options in rebuttal.

of comparison bills that are available, but include an explanation of the variability of bills over the months of the year.[33] Also, the comparison bills should accurately reflect the subject customer's bill cycle, for example, if a customer's September usage is billed on the winter rate due to the customer's billing cycle, all bill comparisons should be based on the winter rate for the customer's bill.

5. Study and retain determinants associated with the creation of a coincident peak demand charge for all classes.

In the Staff Report on Distributed Energy Resources, filed April 5, 2018, in File No. EW-2017-0245, concerning residential and utility-wide rate design, Staff recommended progress towards a rate design that would incorporate an on-peak demand charge to reflect the revenue requirement associated with resource adequacy and capacity costs. Staff recommends Ameren Missouri begin retaining data associated with the potential determinant associated with the creation of a coincident peak demand charge for all classes. An example of the data to be retained would include the highest 15 minute level of usage at any time between 12:01 pm and 6:00 pm on weekdays during the calendar months of June – September, leveraging AMI data as available.[34]

D. Staff recommends certain tariffs be updated as part of the compliance process in this case consistent with processes identified within those tariffs:

1. Update the Facilities Charge on Tariff Sheet 158 (Community Solar Pilot Program) to reflect the changes made to the related energy charges, if applicable;

Tariffs for Ameren Missouri's Community Solar Pilot Program became effective on October 13, 2018.

Per the Amended Unanimous Stipulation and Agreement filed in EA-2016-0207 on May 14, 2018, the Facilities Charge portion of the total solar block charge will be adjusted when rates are reset in future rate cases. The Stipulation further provides that the Facilities Charge rate will be adjusted by the percentage change to volumetric rates in future rate cases, unless a party

[33] For example, if 6 months of bills are available, but those bills are for September through February the explanation should mention that during summer months energy usage associated with cooling will tend to fall during the "on peak" period.

[34] Billing determinants are the quantity of each charge type to be billed to collect an allowed revenue requirement. Every charge type that appears in a company's rate structure must have an associated billing determinant.

provides a cost study demonstrating that it would be unreasonable to adjust the Total Facilities Charge rate by percentage change to volumetric rates in future rate cases post-File No. ER-2016-0179. Ameren Missouri did not request that the Facilities Charge be adjusted as part of this case nor did Ameren Missouri provide a cost study demonstrating that the Facilities Charge should not be adjusted as part of this case. Based on the rate reduction contemplated in this case at this time Staff recommends the Facilities Charge rate be adjusted by the percentage change to the relevant residential and SGS volumetric rates.

2. Update the Renewable Energy Standard Rate Adjustment Mechanism ("RESRAM") Tariff Sheet No. 93.4 to reflect the RESRAM base amount determined in this case;

3. Update the MEEIA margin rates used for calculating the throughput disincentive within the MEEIA mechanism.

E. Staff recommends this case be taken as an opportunity to implement solutions to certain issues that have arisen in other contexts

1. Clarify the billing process for ToU customers

Staff has become aware that a difference may result - due at least in part to the decimals of precision used – between the sum of the on-peak kWh and off-peak kWh used in ToU billing, and the total kWh used in a billing period as indicated by the first and last meter reads.[35] Staff recommends that the Commission clarify that beginning and end meter reads are the appropriate determinant of kWh consumed; in the alternative Staff would not object to a provision in Ameren Missouri's ToU tariff schedules stating that if it is necessary to adjust interval usage for purposes of bill calculations, that the total usage as determined by beginning and ending meter reads should be prorated based on the interval usage recorded for that billing period.

i. Revenue Treatment for Potential Customer Renewable Energy Credit Program

On November 8, 2019, Ameren Missouri filed to extend its Pure Power Program through June 30, 2020. Based, on Ameren Missouri's filing letter in JE-2020-0077, discussions with other

[35] Tariff Sheet No. 63 was filed with the tariffs initiating this case, as well as in EE-2019-0382. The ToU billing issue appears to be related to the existing ToU rate, Ameren Missouri's proposed ToU rates, and Staff's recommended ToU rates.

parties are ongoing to discuss and consider changes that Ameren Missouri has proposed in conjunction with eliminating the pilot status of the program. Depending on the outcome of those discussions, Ameren Missouri's current REC purchase and retirement facilitation program may expire on June 30, 2020. Should this program, or a revised program continue, Staff will likely recommend that revenues should offset the capital cost of the investment with which the related RECs are associated. Staff will further explore this proposal with Ameren Missouri during the Pure Power Program discussions, but wanted to tee it up in the rate case to establish the framework to potentially record the revenue as an offset to rate base.

ii. Stipulation and Agreement in ET-2018-0132 concerning line extension record retention

In the October 4, 2018 Stipulation and Agreement in ET-2018-0132 Ameren Missouri committed to record customer contribution values by voltage and service classification. Ameren Missouri was unable to produce records consistent with this commitment when requested in this case. See Data Request No. 0470 and Response, attached in its entirety as Schedule SLKL-d1. Staff is pursuing additional discovery concerning Ameren Missouri's compliance with this matter.

F. Staff recommends establishment of a ToU rate schedule to be applicable to separately-metered EV charging equipment, on an opt-in basis.[36]

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

V. FAC Tariff Issues

Staff provides its recommendations for the issues that have an impact on Ameren Missouri's FAC and FAC tariff sheets, as listed below.

Revised Base Factors

Staff recommends the Base Factor ("BF") rates be rebased as follows: summer BF $2.087 and winter BF $0.761 cents/kWh[37] based upon an analysis of data compiled during the 12 months

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[36] At this time, Staff does not object to the general design proposed by Ameren Missouri for this purpose. Final design of this rate is dependent on the revenue requirement established in this matter.

[37] Months included in each corresponding BF: Summer (June – September); Winter (October – May).

ending December 2018 (*see* Confidential Schedule LMW-d1[38]). Staff will true-up its recommended BF summer and winter rates in its True-up surrebuttal testimony to be filed on February 14, 2020.

Revised Transmission Percentage

Staff calculated the percentage of MISO-related transmission services costs and revenues arising from sales and purchases for load to be 1.35%.[39]

Staff Expert/Witness: Lisa Wildhaber

VI. Appendices

Appendix 1 - Staff Credentials

Appendix 2 - Other Staff Schedules

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[38] Confidential Schedule LMW-d1 information is included in the work papers of Staff witness Lisa M. Ferguson.

[39] See Work paper titled "C_ER-2019-0335_MISO Rev Exp_Ferguson".

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 Decrease Its Revenues for Electric Service	)))	Case No. ER-2019-0335

AFFIDAVIT OF CONTESSA KING

STATE OF MISSOURI	)	
	)	ss.
COUNTY OF COLE	)	

COMES NOW CONTESSA KING and on her oath declares that she is of sound mind and lawful age; that she contributed to the foregoing *Staff's Direct Class Cost of Service Report*; and that the same is true and correct according to her best knowledge and belief.

Further the Affiant sayeth not.

Contessa King

CONTESSA KING

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 17th day of December, 2019.

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 Decrease Its Revenues for Electric Service	)))	Case No. ER-2019-0335

AFFIDAVIT OF ROBIN KLIETHERMES

STATE OF MISSOURI COUNTY OF COLE	)))	ss.

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

Further the Affiant sayeth not.

Robin Kliethermes

ROBIN KLIETHERMES

JURAT

Subscribed and sworn before me, a duly constituted and authorized Notary Public, in and for the County of Cole, State of Missouri, at my office in Jefferson City, on this 18th day of December, 2019.

D. SUZIE MANKIN
Notary Public - Notary Seal
State of Missouri
Commissioned for Cole County
My Commission Expires: December 12, 2020
Commission Number: 12411070

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 Decrease Its Revenues for Electric Service	)))	Case No. ER-2019-0335

AFFIDAVIT OF SARAH L.K. LANGE

STATE OF MISSOURI COUNTY OF COLE	)))	ss.

COMES NOW SARAH L.K. LANGE and on her oath declares that she is of sound mind and lawful age; that she contributed to the foregoing *Staff's Direct Class Cost of Service Report*; and that the same is true and correct according to her best knowledge and belief.

Further the Affiant sayeth not.

Sarah L.K. Lange

SARAH L.K. LANGE

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 18th day of December, 2019.

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 Decrease	)	Case No. ER-2019-0335
Its Revenues for Electric Service	)	

AFFIDAVIT OF KAREN LYONS

STATE OF MISSOURI	)	
	)	ss.
COUNTY OF JACKSON	)	

COMES NOW KAREN LYONS and on her oath declares that she is of sound mind and lawful age; that she contributed to the foregoing *Staff's Direct Class Cost of Service Report*; and that the same is true and correct according to her best knowledge and belief.

Further the Affiant sayeth not.

Karen Lyons

KAREN LYONS

JURAT

Subscribed and sworn before me, a duly constituted and authorized Notary Public, in and for the County of Jackson, State of Missouri, at my office in Kansas City, on this 18th day of December, 2019.

NOTARY PUBLIC NOTARY SEAL STATE OF MISSOURI

M. RIDENHOUR
My Commission Expires
July 22, 2023
Platte County
Commission #19603483

M. Ridenhour

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 Decrease Its Revenues for Electric Service	)))	Case No. ER-2019-0335

AFFIDAVIT OF LISA WILDHABER

STATE OF MISSOURI	)	
	)	ss.
COUNTY OF COLE	)	

COMES NOW LISA WILDHABER and on her oath declares that she is of sound mind and lawful age; that she contributed to the foregoing *Staff's Direct Class Cost of Service Report*; and that the same is true and correct according to her best knowledge and belief.

Further the Affiant sayeth not.

Lisa Wildhaber

LISA WILDHABER

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 18th day of December, 2019.

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