MISSOURI PUBLIC SERVICE COMMISSION

STAFF REPORT

CLASS COST OF SERVICE

THE EMPIRE DISTRICT ELECTRIC COMPANY

CASE NO. ER-2019-0374

Jefferson City, Missouri
January 29, 2020

** Denotes Confidential Information **

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I. Executive Summary

Empire's current tariffed rates on an annualized and normalized basis produce revenues of $485 million. The temporary tax rider implemented on August 30, 2018 through Case No. ER-2018-0228 reduces this amount by approximately $17.8 million, to approximately $467.5 on an annualized and normalized basis.

In the Cost of Service Report filed on January 15, 2020, Staff determined that Empire's total cost of service is approximately $492 million, and once netted for the Empire Missouri retail jurisdictional portion of other revenues, that Empire's rate schedules should be revised to produce revenues of approximately $448.9 million, a reduction of approximately $36.4 million.[1]

Staff studied the rates of return produced by Empire's rate classes, as described further within this Report, at the revenues produced by current tariffed rates, with and without the impact of the temporary tax rider as a reduction to class revenues. Those results are provided below, as well as Staff's approximate recommended class revenues after implementing the above-described decrease to Empire's Missouri jurisdictional revenue requirement.[2]

Average Rate of Return by Class	Residential	CB/SH	GP/TEB	LPS	Feed & Grain	Contract Transmission	Lighting
Current tariffed rates	6.78%	12.83%	12.50%	12.10%	-36.17%	7.48%	30.35%
Current rates net of tax credit	5.53%	11.37%	11.12%	10.90%	-37.28%	6.30%	28.70%
Staff recommended class revenues	5.53%	8.06%	8.42%	8.33%	-36.17%	6.30%	28.70%

Staff recommends that the Feed & Grain rate schedule revert to its pre-tax reduction tariffed revenue level. Staff recommends that the Residential, Contract Transmission, and Lighting rate schedules retain the current level of revenue production which is net of the current

[1] Staff did not include the plug for expected changes due to true-up in this CCOS.

[2] All class revenue requirements and rate recommendations are subject to changes associated with the final ordered revenue requirement and any additional revisions in billing determinants. Energy efficiency cost recovery has not been segregated from overall revenues and cost of service in these values at this time.

temporary tax reduction rider, and that the CB/SH, GP/TEB, and LPS class revenue requirements be adjusted by the following process:[3]

> Reduce class revenue requirements by the level of the temporary tax reduction;
>
> Determine the amount of additional reduction available after the above-referenced reductions have been applied, (approximately $18.5 million at Staff's recommended revenue requirement);
>
> Further reduce the CB/SH and LPS revenue requirements by 25% each of the amount identified in step 2;
>
> Further reduce the GP/TEB revenue requirements by 50% of the amount identified in step 2.

II. Class Cost of Service ("CCOS") Results and Recommendation

Rate Design Recommendation Summary

Staff recommends the existing residential customer charge be maintained, and that the recommended reduction to the class revenue requirement be applied as an equal amount to each energy rate element. This results in customer effective rates being held constant to those currently experienced by customers pursuant to the temporary tax rider. The resulting rates at Staff's recommended residential revenue requirement are provided below[4]:

Residential	Staff Rate Design	
Customer Charge	$	13.00
Summer 0-600	$	0.12490
Summer 601+	$	0.12490
Winter 0-600	$	0.12490
Winter 600+	$	0.10058

Staff recommends that the CB and SH rate schedules be realigned for consistency of all rate elements except the charge for non-summer usage in excess of 700 kWh per customer per

[3] The provided class names refer to the indicated rate schedules: "Residential"- Residential Service; "CB/SH" – Commercial Service and Small Heating Service; "GP/TEB"- General Power Service and Total Electric Building Service; "LPS" - Large Power Service; "Feed & Grain" – Feed Mill and Grain Elevator Service, Schedule PFM; Contract Transmission - Special Transmission Service; and Lighting – Schedules SPL, PL, LS, MS, and other derivative schedules.

[4] In the event that changes to the non-customer portion of the residential revenue requirement are ordered, Staff provides further recommendations in the body of this Report.

month. Staff recommends the GP and TEB rate schedules be consolidated, and that the Feed & Grain rate schedule rates be held constant in this case and that the Feed & Grain rate schedule be merged into the consolidated GP and TEB rate schedule in a future proceeding. Staff generally recommends that non-residential revenue requirement changes from the revenues produced by existing rates be implemented as an equal percentage adjustment to all rate elements as isolated for the voltage-adjusted cost of energy obtained to serve load.

Other Recommendations Summary

Staff recommends the following:

1) Implementation of an RSM;
2) Improvement of load-data acquisition and retention;
3) Improvement of distribution system cost and usage data retention and accessibility;
4) Correction of any misalignments that have developed due to cyclical billing;
5) Certain FAC tariff changes.

Staff Expert/Witness: Sarah L.K. Lange

III. Sales Reconciliation to Levelized Expectations

Staff's proposed Sales Reconciliation to Levelized Expectations ("SRLE") is a rate mechanism designed to account for weather and conservation for customers served on the Residential, CB, and SH rate schedules. Staff recommends that while the mechanisms be identical, two separate reconciliations would occur, with one reconciliation and resulting rate to be applicable to customers served on the Residential schedule, and a separate reconciliation and resulting rate to be applicable to customers served on the CB and SH schedules. In its direct filing Empire requested a Revenue Stabilization Mechanism ("RSM") pursuant to 386.266.3 RSMo, which states:

> 3. Subject to the requirements of this section, any gas or electrical corporation may make an application to the commission to approve rate schedules authorizing periodic rate adjustments outside of general rate proceedings to adjust rates of customers in eligible customer classes to account for the impact on utility revenues of increases or decreases in residential and commercial customer usage due to variations in either

> weather, conservation, or both. No electrical corporation shall make an application to the commission under this subsection if such corporation has provided notice to the commission under subsection 5 of section 393.1400. For purposes of this section: for electrical corporations, "eligible customer classes" means the residential class and classes that are not demand metered; and for gas corporations, "eligible customer classes" means the residential class and the smallest general service class. As used in this subsection, "revenues" means the revenues recovered through base rates, and does not include revenues collected through a rate adjustment mechanism authorized by this section or any other provisions of law. This subsection shall apply to electrical corporations beginning January 1, 2019, and shall expire for electrical corporations on January 1, 2029.

Staff recommends Empire incorporate into its tariff a mechanism similar to the settled-upon Volumetric Indifference Reconciliation to Normal ("VIRN") that was approved in the Ameren Missouri gas rate case, Case No. GR-2019-0077 as an alternative to the Empire-proposed RSM. The relevant portion of Ameren Missouri's gas tariff is attached for reference as Appendix 3, Schedule SLKL-d1. Staff witness Michael L. Stahlman will address specific concerns with Empire's proposed RSM in his rebuttal testimony.

To develop breakpoints between blocks that are reasonably related to the portion of usage per customer per month that may be subject to variation due to weather and conservation, Staff has reviewed Empire's cumulative frequency distribution data to determine the maximum level of usage per customer per month that is more or less constant all year. Usage of approximately 400 kWh per customer per month appears unlikely to be impacted by weather or conservation in the immediate future. [5]

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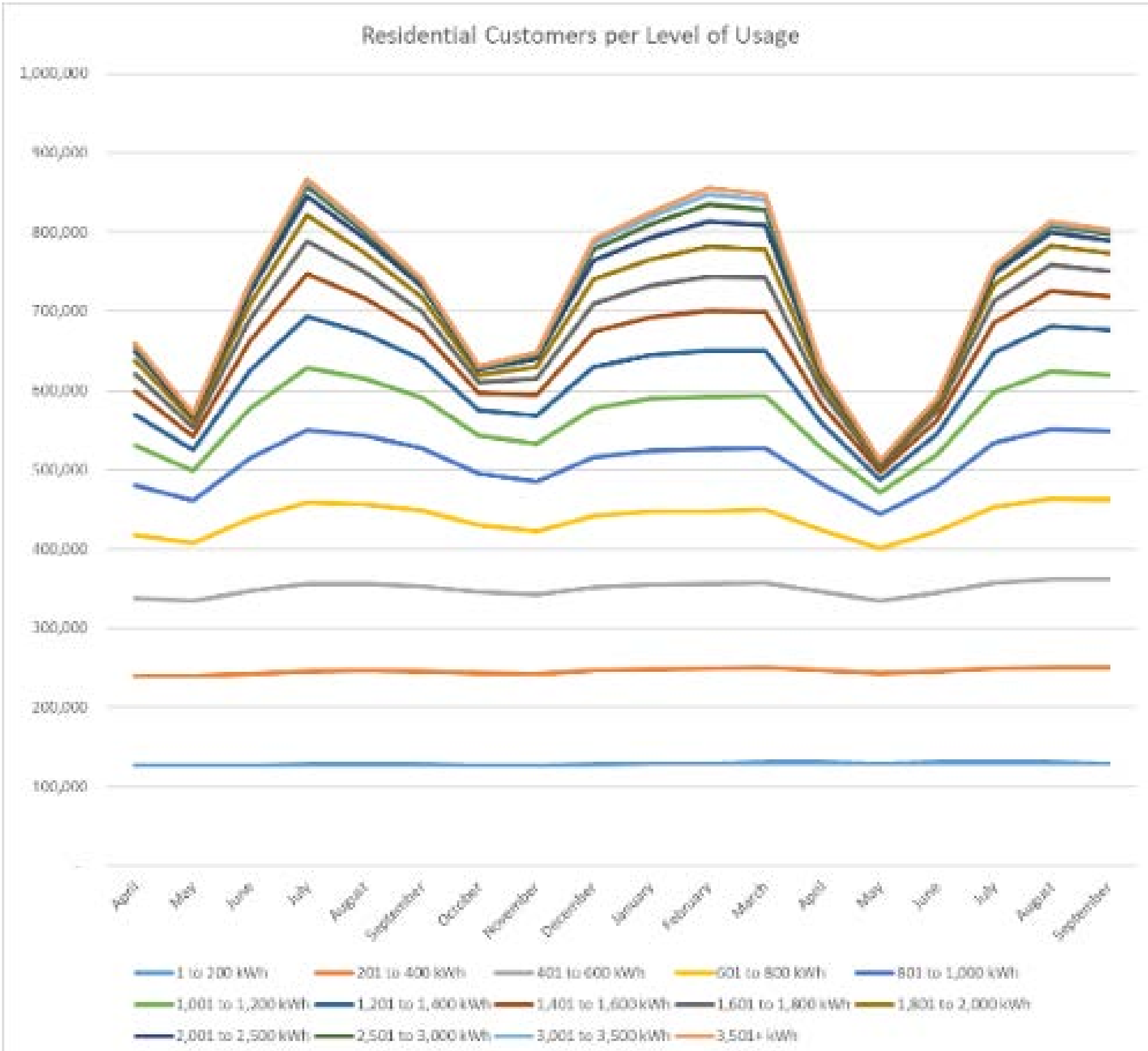
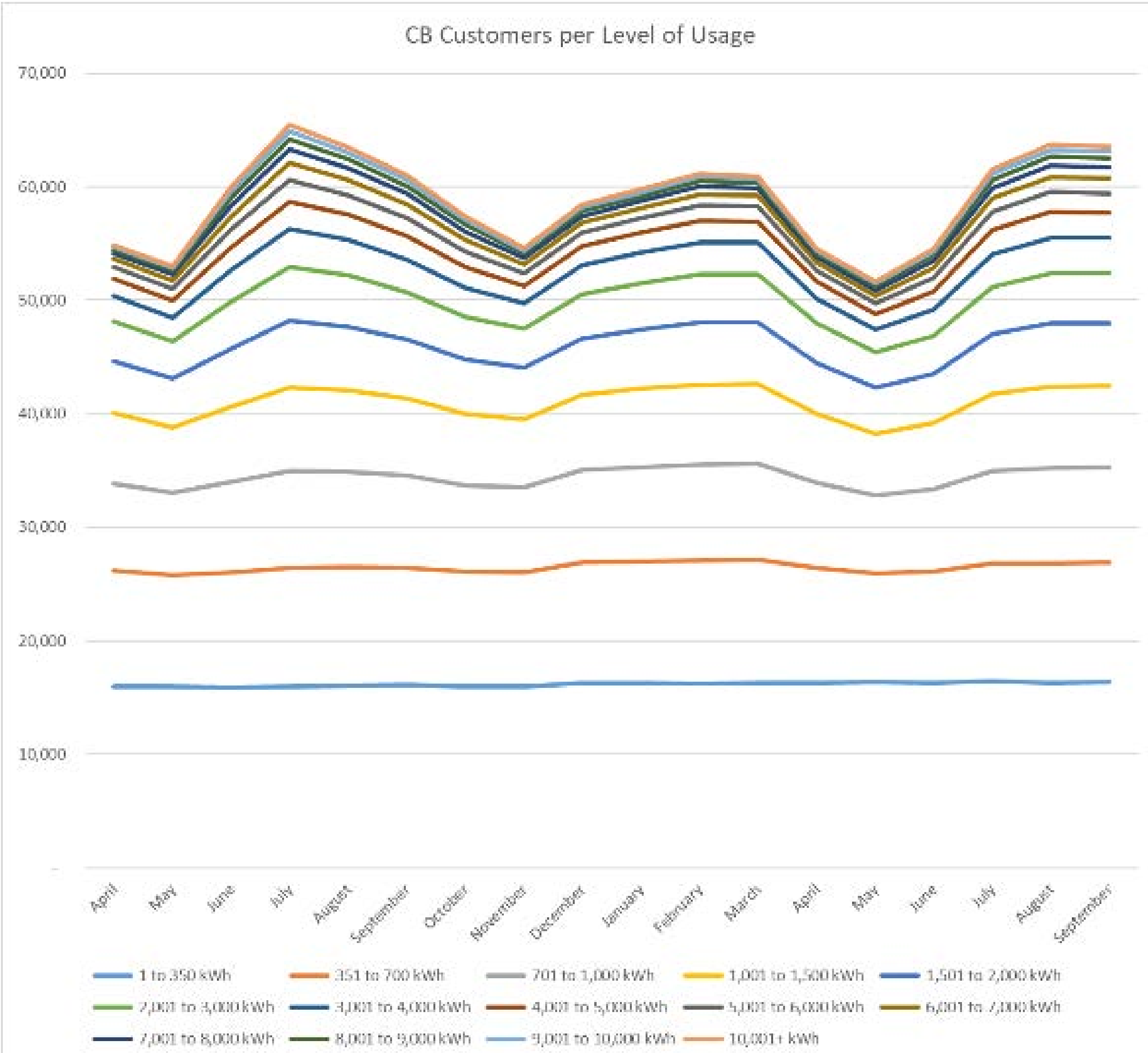
[5] It is possible that with sustained energy efficiency and conservation activities on the part of Empire's customers, or with a change in housing stock resulting in lower per-meter average consumption due to smaller and/or more efficient homes, that this level may change in future rate proceedings.



To facilitate reconciliation of expected revenues above 400 kWh per month per customer, while retaining Empire's exposure to changes in revenue below 400kWh per month per customer, Staff recommends creation of a third residential block within Empire's billing system at this breakpoint, while the rate that is in place for the first 400 kWh of each customer's usage each month would be identical to the rate that is in place for each customer's 401 – 600 kWh of usage each month.

Staff also reviewed the number of customers taking service on the CB and SH rate schedules per level of usage, as CB stand-alone, SH stand-alone, and with the classes combined. The maximum level of consistent usage was 700 kWh per customer per month under all three approaches, although the line indicating usage of 700 kWh per CB/SH customer per month is less consistent than the line indicating usage of 400 kWh per residential customer per month.



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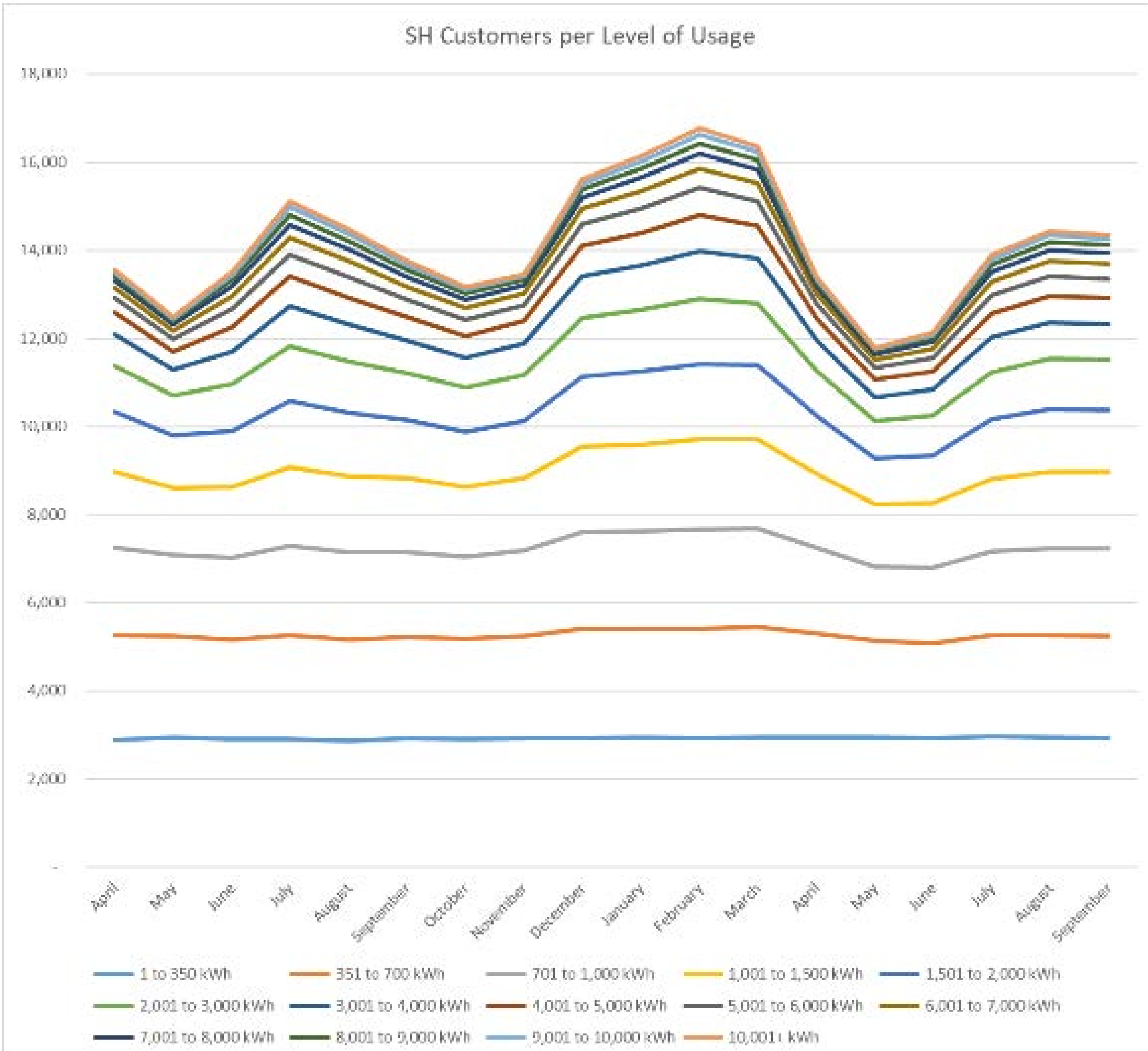

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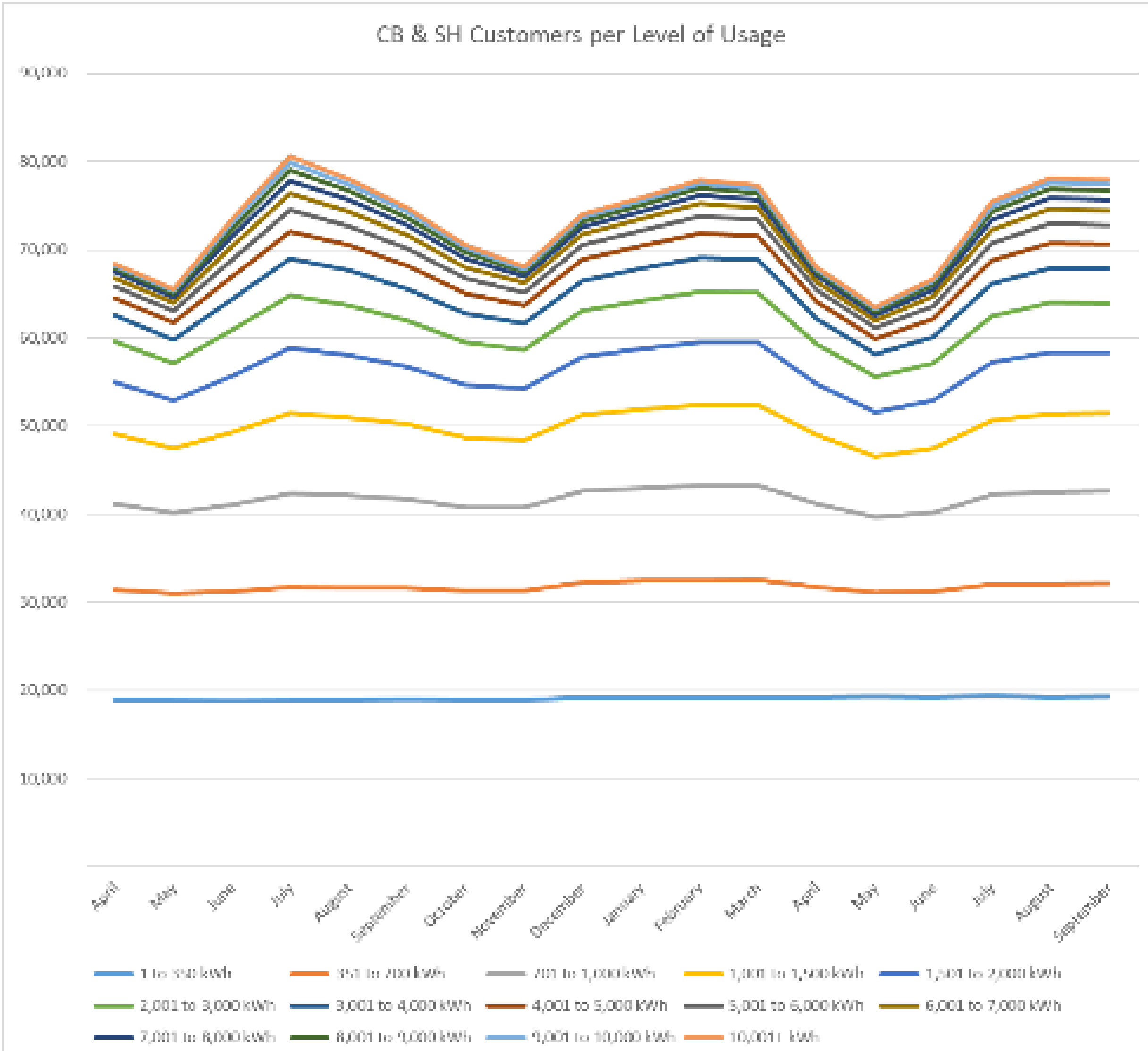

Because this break point of 700 kWh per customer per month aligns with the existing Empire rate structure for a block break point at 700 kWh per customer per month, no additional billing system changes are necessary to accommodate a CB/SH SRLE mechanism.

Staff's Residential SRLE is designed to, on an annual basis, reconcile the revenues realized from sales in excess of 400 kWh per customer per month, net of the FAC base factor per kWh, to the revenues that were assumed to be realized in aggregate from those sales, net of the FAC base factor per kWh.[6] At Staff's direct recommended revenue requirement and residential rate design, those assumed net revenues are provided below, by block, with the SRLE – reconciled totals shaded in blue.[7]

Sales Reconciliation to Levelized Expectations **Residential**	Staff Recommended Residential Rates	Rates Net of FAC Base Factor	Revenues per Block Net of FAC Base Factor
Summer 0-400	$ 0.12490	$ 0.10136	$ 20,991,121
Summer 401-600	$ 0.12490	$ 0.10136	$ 6,473,788
Summer 601+	$ 0.12490	$ 0.10136	$ 26,632,353
Winter 0-400	$ 0.12490	$ 0.10136	$ 41,982,241
Winter 401-600	$ 0.12490	$ 0.10136	$ 11,451,406
Winter 600+	$ 0.10058	$ 0.07704	$ 46,256,018

However, in the actual reconciliation process, the revenues per block are not relevant, only the aggregate amount, which is to be trued-up against actual sales on an annual basis. So if an atypically mild winter is experienced in the same annual period as an atypically warm summer, or vice versa, the resulting SRLE adjustment will reflect these offsetting impacts. The total SRLE protected revenues are to be reconciled against, as well as the other components of Staff's recommended residential revenue recovery (using Staff's direct-recommended FAC base factor), are provided below:[8]

Residential SRLE		
SRLE Protected Recovery	$	90,813,564
FAC Protected Recovery	$	39,117,380
Non-FAC / Non-SRLE Protected Recovery	$	62,973,362
Customer Charge Recovery	$	20,467,668

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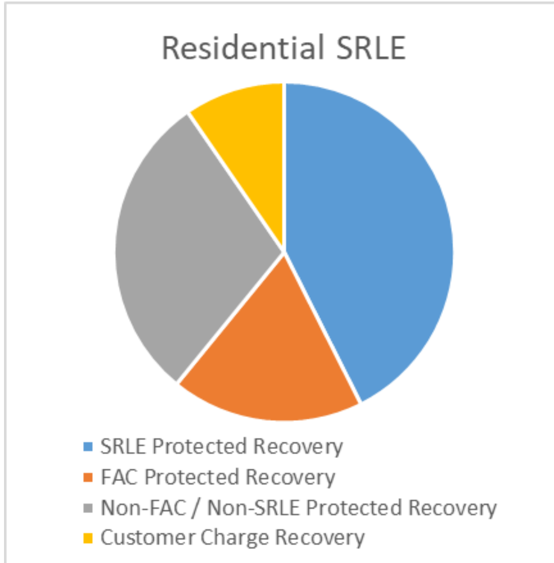
[6] Any energy efficiency charges or other riders would also be excluded.

[7] All values are subject to adjustment consistent with the final ordered revenue requirement, rate design, billing determinants, FAC base factor, and voltage adjustment factors.

[8] These amounts do not include the energy efficiency recovery charge.



Staff's CB/SH SRLE is designed to, on an annual basis, reconcile the revenues realized from sales in excess of 700 kWh per customer per month, net of the FAC base factor per kWh, to the revenues that were assumed to be realized in aggregate from those sales, net of the FAC base factor per kWh. [9]

An issue that complicates implementation of the SRLE or any RSM is the presence of extraordinarily large customers within the CB/SH class that are likely more appropriately served on a different rate schedule. For the twelve months of most recent customer data available, total usage by CB and SH customers was approximately 400 million kWh, by approximately 22,900 customers. However, only 525 of those customers (less than 3%) are responsible for over 71.5 million kWh of the usage (over 17%). The decision of one or more of these customers to switch to the GP class would result in a sizable adjustment under the SRLE to compensate Empire for either a customer terminating service, or even for a customer switching the rate schedule under which that customer receives service. The first is not the purpose of a RSM, and the second is neither the purpose of a RSM nor reasonable. While it is not feasible to track all changes in customer growth for segregation from the SRLE

[9] Any energy efficiency charges or other riders would also be excluded.

or similarly-designed RSM, Staff recommends that in implementing any RSM the following measures be taken:

1. RSM determinants will be reduced for the usage of any customer using more than 100,000 kWh in the prior year.

2. RSM determinants will be reduced for the usage of any customer switching the rate schedule under which that customer receives service.

Staff has estimated the impact of reducing the usage for customers using more than 100,000 kWh, as provided below:

CB/SH	Total	Adjustment	Adjusted
Customer Charge	242,244	6,300	235,944
Summer 0-700	37,735,810	4,410,000	33,325,810
Summer 701+	107,595,415	27,159,283	80,436,132
Winter 0-700	73,472,237	4,410,000	69,062,237
Winter 700+ CB	133,347,368	29,996,384	103,350,984
Winter 700+ SH	43,687,270	9,606,015	34,081,255

At Staff's direct recommended revenue requirement and CB/SH rate design, those assumed net revenues are provided below, by block: [10]

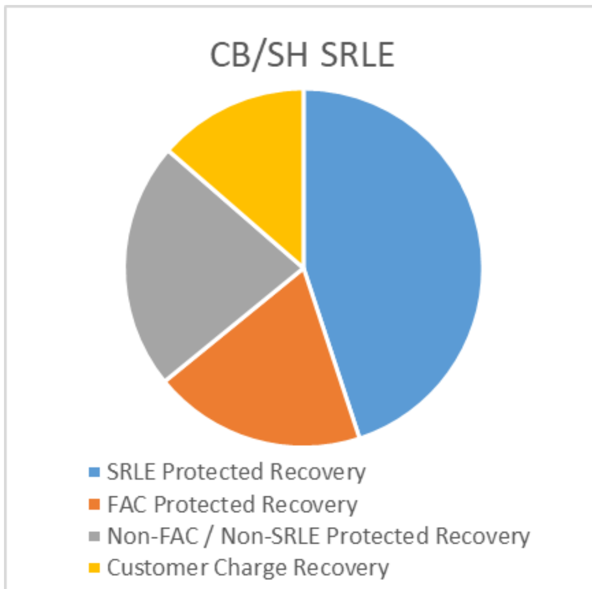
Sales Reconciliation to Levelized Expectations	Staff Recommended CB/SH Rates	Rates Net of FAC Base Factor	Revenues per Block Net of FAC Base Factor
CB/SH			
Summer 0-700	$ 0.10925	$ 0.08570	$ 2,856,121
Summer 701+	$ 0.10925	$ 0.08570	$ 6,893,616
Winter 0-700	$ 0.10925	$ 0.08570	$ 5,918,839
Winter 700+ CB	$ 0.10563	$ 0.08209	$ 8,483,908
Winter 700+ SH	$ 0.09140	$ 0.06785	$ 2,312,502

In the actual reconciliation process, the revenues per block are not relevant, only the aggregate amount. The total SRLE protected revenues to be reconciled against, as well as the other

[10] All values are subject to adjustment consistent with the final ordered revenue requirement, rate design, billing determinants, FAC base factor, and voltage adjustment factors.

components of Staff's recommended CB/SH revenue recovery (using Staff's direct-recommended FAC base factor) are provided below:

CB/SH SRLE		
SRLE Protected Recovery	$	17,690,026
FAC Protected Recovery	$	7,540,437
Non-FAC / Non-SRLE Protected Recovery	$	8,774,960
Customer Charge Recovery	$	5,353,569



An advantage of the SRLE is the elimination of the throughput disincentive, whether Empire promulgates energy efficiency programs pursuant to MEEIA[11] or otherwise, for the Residential, CB, and SH rate schedules. Thus, if Empire pursues a MEEIA program the "TD" adjustment found in the mechanisms of other utilities would be subsumed within the SRLE design for the Residential, CB, and SH rate schedules.

It is reasonable to reconcile the SRLE on an annual basis for a number of reasons. First, simplicity and consistency for both customers and the utility as they benefit from fewer filings and rate changes. While the Commission has placed increasing interest in the rate design of the residential rate schedules with an apparent eye towards incenting behaviors that will reduce

[11] Section 393.1075, RSMo.

overall system costs, those incentives are dampened by frequent shifts of total experienced rates due to changes in FAC and other rider rates. Second, the intent of an RSM is to stabilize utility revenues to reduce financial impact to the utility associated with customer responses to weather and customer conservation of energy, as discussed above. Finally, annual reconciliation under the SRLE will smooth some of the revenue and customer bill volatility that the FAC introduces through its operation within the integrated market paradigm that arose shortly after the FACs were implemented for Missouri electric utilities.[12] Full alignment of the SRLE and the FAC would not enable the offsetting of revenues within a year as discussed above, and is complicated by certain timing aspects. [13]

FAC Accumulation periods begin September 1st and March 1st of each year, and FAC Recovery Periods begin June 1st and December 1st. The summer billing period pursuant to the Residential, CB, and SH rate schedules begins June 16, and ends September 15. Also, a projection period is necessary for operation of the SRLE between the time a SRLE adjustment rate is calculated, the tariff sheet to implement the rate change is filed, and the tariff sheet is promulgated. The final design of the SRLE tariff will require significant input from Empire as to the dates that billing system data becomes available concerning appropriate start dates, filing dates, and the proration of partial years.

Staff Expert/Witness: Sarah L.K. Lange

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[12] For example, if winter weather is colder than normal, it is likely that Empire's sales will be up, and Empire will collect more revenue than under normalized conditions. However, Empire will have likely experienced higher Total Energy Costs under the FAC, due to procurement of more energy and at a higher cost from the integrated market than would have occurred under normalized conditions. In some but not all circumstances these additional costs of energy to serve load may be offset by the net proceeds of sales from Empire's generation fleet. However, given Empire's capacity position, it is likely that the additional revenues net of fuel of selling additional energy at a higher price will not fully offset the additional costs of obtaining more energy at a higher price to serve its load. So, in the short term, each Empire customer who used more energy in the colder month will pay a bigger bill in the cold month because they used more energy, and Empire will receive more non-FAC revenue than it would under normalized conditions. Then, a few months later, all Empire customers will see an increase in the FAC portion of their bill because Empire paid more for the energy it bought to serve those customers, offset by any additional profit Empire made selling energy into the market, and Empire will receive the FAC revenue. The reverse of this is also applicable to milder-than-normal conditions, when customers will pay lower bills, and Empire will receive lower revenues, through both base rates and the FAC rider. Thus, as currently implemented the FAC exacerbates revenue and bill volatility associated with changes in energy consumption due to weather – but it spreads it out over time. Spreading out the SRLE over an annual period allows for an offset of FAC-induced volatility as it relates to changes in the FAC associated with weather-related energy price volatility.

[13] As noted in the FAC section of this Report, while Staff witness Brooke Mastrogiannis recommends some modifications to the FAC, Staff recommends its continuation. This discussion is intended simply to illustrate the many considerations that should be taken into account in designing an RSM to work in conjunction with an FAC.

A. Residential Rate Design

Provided below are Empire's current tariff rates, the tariff rates net of the temporary tax rider, and Empire's proposed rates for this case[14]

	Current		Current Effective		Requested YE-2020-0029	
Residential						
Temp. Tax Reduction	$	0.00516				
Customer Charge	$	13.00	$	13.00	$	19.00
Summer 0-600	$	0.13006	$	0.12490	$	0.12754
Summer 601+	$	0.13006	$	0.12490	$	0.12754
Winter 0-600	$	0.13006	$	0.12490	$	0.12754
Winter 600+	$	0.10574	$	0.10058	$	0.10574

B. Residential Customer Charge

The functionalized residential customer charge calculated within Staff's CCOS is $11.91. Costs included in the calculation of the Residential customer charge are the costs necessary to make electric service available to the customer, regardless of the level of electric service utilized. Examples of such costs include monthly meter reading, billing, postage, customer accounting service expenses, as well as a portion of the costs associated with the required investment in a meter, the service line ("drop"), and other billing costs. The costs included for recovery through the customer charge consist of the following:[15]

- Distribution – services (investment and expenses)
- Distribution – meters (investment and expenses)
- Distribution – customer installations
- Customer deposit
- Customer meter reading
- Other customer billing expenses
- Uncollectible accounts (write-offs)

[14] The energy efficiency cost recovery charges are omitted from these tables.

[15] The $11.91 calculated customer charge does not include an allocated portion of costs related to income taxes and administrative and general expenses. The inclusion of these costs would increase the residential customer charge calculated.

- Customer service & information expenses
- Sales expense

Consistent with Staff's rate design recommendation to maintain the residential class' current cost responsibility net of the temporary tax rider, Staff recommends the customer charge be maintained at $13.00. This will mitigate potential rate shock in the next rate proceeding associated with the expected inclusion of AMI meter costs in Empire's revenue requirement.

Staff Expert/Witness: Robin Kliethermes

C. Residential Energy Charges

Consistent with the recommendation that the existing residential customer charge be maintained, Staff recommends that the recommended reduction to the class revenue requirement be applied as an equal amount to each energy rate element. This results in customer effective rates being held constant to those currently experienced by customers pursuant to the temporary tax rider, provided under the "current effective" heading above.

In the event that decreases to the non-customer portion of the residential revenue requirement are ordered that are in excess of those contemplated above, Staff recommends the decrease to the residential revenue requirement be implemented by first setting the charges for usage in excess of 600 kWh to the "current effective" rates that result from applying the temporary tax reduction to the current tariffed rates. The additional decrease would then be applied as the same percentage decrease to the charges applicable to 0-600 kWh of usage for each season.[16] An example of the implementation of this rate design, were the residential class to receive a system-average level of decrease, is provided below.

Residential	Staff Rate Design
Customer Charge	$ 13.00
Summer 0-600	$ 0.12284
Summer 601+	$ 0.12490
Winter 0-600	$ 0.12284
Winter 600+	$ 0.10058

[16] In the event the reduction applicable to residential energy charge recovery does not exceed the approximate $8.5 million currently generated by the application of the temporary tax reduction to the residential class, then the tail block charges should be set equal to the current tariff tail block charges, with the decrease applied as an equal percentage reduction to the charges for usage from 0-600 kWh per month, by season.

D. Non-Residential Rate Structures and Rate Design

1. CB/SH Alignment and Rate Design

	Current	Current Effective	Requested YE-2020-0029
CB			
Temp. Tax Reduction	$ 0.00502		
Customer Charge	$ 22.69	$ 22.69	$ 25.00
Summer 0-700	$ 0.13168	$ 0.12666	$ 0.13326
Summer 701+	$ 0.13168	$ 0.12666	$ 0.13326
Winter 0-700	$ 0.13168	$ 0.12666	$ 0.13326
Winter 700+	$ 0.11838	$ 0.11336	$ 0.11980
SH			
Temp. Tax Reduction	$ 0.00475		
Customer Charge	$ 22.69	$ 22.69	$ 25.00
Summer 0-700	$ 0.12872	$ 0.12397	$ 0.12987
Summer 701+	$ 0.12872	$ 0.12397	$ 0.12987
Winter 0-700	$ 0.12872	$ 0.12397	$ 0.12987
Winter 700+	$ 0.09616	$ 0.09141	$ 0.09702

The assumed distinction for the SH and CB rate schedules is that space heating customers will use significantly more energy in the non-summer months, and will have a higher load factor than similarly-sized CB customers. Under this assumption, it is not unreasonable to discount the tail block for non-summer usage of SH customers so they do not over-contribute to the cost of maintaining the transmission and distribution system; and it is also assumed that more usage will occur off-peak, thus a discount for off peak usage's lower energy cost and reduced impact on generating capacity is warranted.[17]

Realigning the charge for all non-tailblock rate elements results in a charge of approximately $0.13114 per kWh for all energy charges for both the CB and SH rate schedules, while maintaining the existing tail block rate for each rate schedule. Staff recommends this realignment be undertaken prior to any other rate design implementation, and that the like-charges be held constant on both rate schedules regardless of the rate design implemented.

[17] Any discrepancy in cost of service as discussed here is better recognized with time-variant charges, potentially including a coincident demand charge.

For implementing any overall reduction in the revenue requirement of the realigned CB and SH schedules, collectively the CB/SH class, Staff recommends a multistep process that includes isolating the cost of energy to serve load within the energy charge from further adjustment.[18] After isolating the energy costs, for the CB/SH class, Staff recommends the decrease be applied to the charges for usage within each rate schedule applicable to the first 700 kWh of usage each month, maintaining the consistency of these rate elements across the two rate schedules. At Staff's recommended level of class revenue responsibility, one third of the percentage reduction applied to the energy-isolated first blocks should be applied to the CB energy-isolated winter tail block, and one half of the percentage reduction applied to the energy-isolated CB winter tail block should be applied to the energy-isolated SH winter tail block. The adjustment of winter tail blocks is only appropriate if the failure to apply this step would result in inverted rate designs. The approximate rates that result from this design at Staff's recommended CB/SH revenue requirement are provided in the table below:

CB/SH	**Staff Rate Design**
Customer Charge	$ 22.69
Summer 0-700	$ 0.10925
Summer 701+	$ 0.10925
Winter 0-700	$ 0.10925
Winter 700+ CB	$ 0.10563
Winter 700+ SH	$ 0.09140

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[18] To simplify this process Staff uses the market average cost of Day-Ahead energy as adjusted for class-applicable voltage only, and has not attempted to incorporate the other costs associated with procurement of energy in the SPP integrated energy market.

2. GP/TEB Consolidation

	Current		Current Effective		Requested YE-2020-0029	
GP						
Temp. Tax Reduction	$	0.00370				
Customer Charge	$	69.49	$	69.49	$	80.00
Summer Demand	$	7.33	$	7.33	$	7.33
Winter Demand	$	5.71	$	5.71	$	5.71
Facilities Demand	$	2.07	$	2.07	$	2.07
Summer 1st 150 HU	$	0.09024	$	0.08654	$	0.09024
Summer 2nd 200 HU	$	0.07084	$	0.06714	$	0.07084
Summer Add. HU	$	0.06398	$	0.06028	$	0.06398
Winter 1st 150 HU	$	0.07799	$	0.07429	$	0.07799
Winter 2nd 200 HU	$	0.06420	$	0.06050	$	0.06420
Winter Add. HU	$	0.06368	$	0.05998	$	0.06368
TEB						
Temp. Tax Reduction	$	0.00408				
Customer Charge	$	69.49	$	69.49	$	72.00
Summer Demand	$	3.50	$	3.50	$	3.49
Winter Demand	$	2.88	$	2.88	$	2.87
Facilities Demand	$	2.13	$	2.13	$	2.13
Summer 1st 150 HU	$	0.10817	$	0.10409	$	0.10794
Summer 2nd 200 HU	$	0.08472	$	0.08064	$	0.08454
Summer Add. HU	$	0.07665	$	0.07257	$	0.07648
Winter 1st 150 HU	$	0.08272	$	0.07864	$	0.08254
Winter 2nd 200 HU	$	0.06705	$	0.06297	$	0.06690
Winter Add. HU	$	0.06580	$	0.06172	$	0.06566

The assumed distinction for the GP and TEB rate schedules is similar to that assumed for the SH and CB schedules.[19] There is not at this time an apparent cost-related distinction between the service of customers on these rate schedules. Due to the seasonality of Empire's demand charges and the hours use rate structure of these rate schedules, it is reasonable to merge these rate schedules at this time. The overall decrease expected in this case will mitigate any customer impacts that may preclude merger of these schedules under ordinary circumstances.

[19] Time-variant charges, potentially including a coincident demand charge better reflect any differences in cost causation between customers served on these rate schedules.

3. GP/TEB, LP, and Feed & Grain Rate Design

For implementing any overall reductions in the revenue requirement of the consolidated GP/TEB schedule, Staff recommends a multistep process that includes isolating the cost of energy to serve load within the energy charge from further adjustment.[20] After isolating the energy costs, Staff recommends the decrease be applied as an equal percentage within each schedule to the charges for usage net of energy and each other charge as tariffed. The approximate rates that result from this design at Staff's recommended revenue requirement are provided in the table below:

GP/TEB	Staff Rate Design
Customer Charge	$ 58.72
Summer Demand	$ 5.32
Winter Demand	$ 4.08
Facilities Demand	$ 1.77
Summer 1st 150 HU	$ 0.08542
Summer 2nd 200 HU	$ 0.06790
Summer Add. HU	$ 0.06088
Winter 1st 150 HU	$ 0.07200
Winter 2nd 200 HU	$ 0.05968
Winter Add. HU	$ 0.05885

Staff recommends the same process be applied to reduce the LP rates to produce a level of revenues consistent with Staff's recommended LP class revenue requirement. Empire's current tariff rates, the tariff rates net of the temporary tax rider, and Empire's proposed rates for the LP rate schedule are provided below, as well as the rates that result from Staff's recommended application of the Staff-recommended revenue requirement to the LP rate schedule:

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[20] To simplify this process Staff uses the market average cost of Day-Ahead energy as adjusted for class-applicable voltage only, and has not attempted to incorporate the other costs associated with procurement of energy in the SPP integrated energy market.

LP	Current		Current Effective		Requested YE-2020-0029	
Temp. Tax Reduction	$	0.00298				
Customer Charge	$	283.55	$	283.55	$	325.00
Summer Demand	$	15.69	$	15.69	$	15.69
Winter Demand	$	8.66	$	8.66	$	28.66
Facilities Demand	$	1.88	$	1.88	$	2.86
Summer 1st 350 HU	$	0.06809	$	0.06511	$	0.06809
Summer Add. HU	$	0.03683	$	0.03385	$	0.03683
Winter 1st 350 HU	$	0.06048	$	0.05750	$	0.06048
Winter Add. HU	$	0.03552	$	0.03254	$	0.03550

LP	Staff Rate Design	
Customer Charge	$	223.74
Summer Demand	$	12.38
Winter Demand	$	6.83
Facilities Demand	$	1.48
Summer 1st 350 HU	$	0.06002
Summer Add. HU	$	0.03536
Winter 1st 350 HU	$	0.05402
Winter Add. HU	$	0.03432

Staff recommends the currently tariffed Feed & Grain rates be retained, and that the Feed Mill rate schedule be consolidated into the GP/TEB schedule in a future rate proceeding. Given the relatively small number of customers taking service on this schedule, Staff encourages Empire to work one-on-one with customers to understand the impacts of this transition. If a well-designed time-variant rate is in place for the consolidated GP/TEB class at the time of transition, customer impacts should be minimal and may result in overall bill reductions for customers that utilize energy primarily in times of low capacity and energy costs.

continued on next page

Feed & Grain	Current	Current Effective	Requested YE-2020-0029
Temp. Tax Reduction	$ 0.00552		
Customer Charge	$ 27.65	$ 27.65	$ 28.50
Summer 0-700	$ 0.18020	$ 0.17468	$ 17.80000
Summer 701+	$ 0.18020	$ 0.17468	$ 17.80000
Winter 0-700	$ 0.18020	$ 0.17468	$ 17.80000
Winter 700+	$ 0.16370	$ 0.15818	$ 0.16170
EECR	$ 0.00071	$ 0.00071	$ 0.00071

Feed & Grain	Staff Rate Design
Customer Charge	$ 27.65
Summer 0-700	$ 0.18020
Summer 701+	$ 0.18020
Winter 0-700	$ 0.18020
Winter 700+	$ 0.16370

4. Contract Transmission Rate Design[21]

Contract Transmission	Current	Current Effective	Requested YE-2020-0029
Temp. Tax Reduction	$ 0.00245		
Customer Charge	$ 259.01	$ 259.01	$ 275.00
On Peak Summer Demar	$ 25.16	$ 25.16	$ 25.74
On Peak Winter Demanc	$ 17.10	$ 17.10	$ 17.50
Facilities Demand	$ 0.50	$ 0.50	$ 0.51
Summer On-Peak	$ 0.05412	$ 0.05167	$ 0.05537
Summer Shoulder	$ 0.04371	$ 0.04126	$ 0.04472
Summer Off-Peak	$ 0.03373	$ 0.03128	$ 0.03451
Winter On-Peak	$ 0.03838	$ 0.03593	$ 0.03927
Winter Off-Peak	$ 0.03184	$ 0.02939	$ 0.03258
Demand Credit	$ 4.01	$ 4.01	$ 4.01

Staff recommends the existing relationship of on-peak, off-peak, and shoulder rates be realigned to reflect the relationship observed in the simple averages of the test period market energy prices used to determine the cost of energy to serve load in Staff's production modeling.

[21] The described adjustments are also applicable to the Special – Contract Praxair schedule.

Provided below are the actual simple average $/MWH from the indicated time periods within the test period.

Summer On	$ 39.92	212%	of Summer Off Peak Price
Summer Shoulder	$ 28.56	152%	of Summer Off Peak Price
Summer Off	$ 18.83		
NonSummer On	$ 32.46	129%	of NonSummer Off Peak Price
NonSummer Off	$ 25.19		

Using these average prices, Staff isolated the energy costs from the observed energy cost recovery during the test period of a customer taking service pursuant to a transmission contract. Those determinants produced revenues of approximately $640,000 in excess of the energy costs.[22] This generated margin should next be reduced by the class-applicable energy-isolated equal percentage adjustment. The resulting value on a per-kWh basis is approximately $0.00856/kWh. The energy prices by time and season should then be added back into the rate. The resulting rate design at Staff's recommended class revenue requirement is provided below, as well as an indication of the relative prices for each period within each season:

Contract Transmission	Staff Rate Design		
Customer Charge	$ 243.73		
On Peak Summer Demand	$ 23.68		
On Peak Winter Demand	$ 16.09		
Facilities Demand	$ 0.47		
Summer On-Peak	$ 0.04857	177%	of Summer Off Peak Rate
Summer Shoulder	$ 0.03721	135%	of Summer Off Peak Rate
Summer Off-Peak	$ 0.02747		
Winter On-Peak	$ 0.04111	121%	of NonSummer Off Peak Rate
Winter Off-Peak	$ 0.03384		
Demand Credit	$ 3.77		

Staff suggests, based on observed trends in market prices, that in Empire's next rate proceeding, it present a proposal to better capture the seasonality of rates, such as through shifting the

[22] Recall that these energy costs reflect only day-ahead energy costs, and do not include all integrated market costs associated with procuring energy to serve load. For purposes of rate design, this simplified approach is not unreasonable given the relative margins produced from the energy charges over the cost of day-ahead energy for most rate schedules at this time.

summer season to begin in mid-May as opposed to mid-June, and through implementing shoulder month pricing and peak winter month pricing.

5. Movement towards modern rate structures

When sufficient metering and billing technology has been deployed, Staff recommends that Empire adopt time-variant rate structures as discussed 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. In the more immediate future, pending Empire's deployment of AMI and broad-scale billing technology which are necessary for more broadly-deployed ToU, Staff recommends Empire work towards a more seasonally appropriate incorporation of a "shoulder" season. Empire has consistently high demands and usage in the months of December, January, and February. It is most appropriate to charge out the usage in these months at a higher rate than is charged for usage in October, April or similar months. Empire should also begin retaining determinants associated with creation of a coincident peak demand charge to facilitate study of this charge type as a potential element of a more modern rate structure in the future.

Staff Expert/Witness: Sarah L.K. Lange

IV. Market Energy Costs

Staff studied the simple averages of the test period market energy prices used to determine the cost of energy to serve load in Staff's production modeling, as applied to the estimated hourly loads of each class as studied.[23] The annual load-weighted average price, by class, is provided by indicated voltage in the table below:

	Residential	CB/SH	GP/TEB	Large Power	Feed & Grain	Contract Transmission	Lighting	System Average
Average price per kWh @ transmisison volatage:	$ 0.0323	$ 0.0319	$ 0.0311	$ 0.0300	$ 0.0312	$ 0.0293	$ 0.0275	$ 0.0314
Average price per kWh @ customer meter:	$ 0.0310	$ 0.0307	$ 0.0301	$ 0.0293	$ 0.0300	$ 0.0293	$ 0.0264	$ 0.0303

[23] Recall that these energy costs reflect only day-ahead energy costs, and do not include all integrated market costs associated with procuring energy to serve load. For purposes of rate design, this simplified approach is not unreasonable given the relative margins produced from the energy charges over the cost of day-ahead energy for most rate schedules at this time.

The simple average price per hour by month of actual Empire day-ahead energy prices is provided in the table below. Red shading indicates hours in which the average price is at or above 75% of the observed average highest price:

Hour	January	February	March	April	May	June	July	August	September	October	November	December
1	$ 24.18	$ 22.90	$ 23.53	$ 16.82	$ 26.25	$ 16.37	$ 16.26	$ 25.81	$ 17.59	$ 23.99	$ 30.57	$ 28.42
2	$ 23.82	$ 21.26	$ 24.81	$ 17.46	$ 23.13	$ 14.16	$ 14.75	$ 24.88	$ 17.41	$ 23.91	$ 30.55	$ 28.57
3	$ 23.54	$ 20.72	$ 24.24	$ 15.35	$ 19.89	$ 11.89	$ 13.24	$ 22.95	$ 16.04	$ 21.72	$ 30.21	$ 27.63
4	$ 23.67	$ 21.12	$ 23.54	$ 15.31	$ 19.23	$ 10.73	$ 12.16	$ 22.32	$ 15.58	$ 21.19	$ 30.33	$ 27.89
5	$ 23.41	$ 21.06	$ 24.09	$ 15.68	$ 19.38	$ 10.32	$ 11.39	$ 21.61	$ 15.18	$ 21.09	$ 30.39	$ 27.90
6	$ 24.54	$ 22.28	$ 26.57	$ 18.14	$ 20.06	$ 11.02	$ 12.01	$ 21.42	$ 15.76	$ 21.97	$ 33.02	$ 29.88
7	$ 28.14	$ 24.46	$ 34.13	$ 22.00	$ 22.88	$ 13.58	$ 13.41	$ 22.59	$ 17.40	$ 25.74	$ 39.82	$ 33.20
8	$ 33.81	$ 31.77	$ 45.07	$ 30.55	$ 25.98	$ 15.29	$ 14.80	$ 24.31	$ 19.40	$ 32.68	$ 53.86	$ 39.37
9	$ 35.03	$ 31.36	$ 44.75	$ 30.24	$ 29.32	$ 18.46	$ 17.22	$ 25.52	$ 19.58	$ 33.20	$ 52.26	$ 41.79
10	$ 33.50	$ 30.82	$ 42.85	$ 30.88	$ 32.50	$ 21.48	$ 20.16	$ 28.76	$ 21.01	$ 34.42	$ 49.56	$ 40.14
11	$ 36.07	$ 32.87	$ 44.08	$ 32.39	$ 33.03	$ 23.04	$ 22.30	$ 32.04	$ 22.83	$ 38.06	$ 52.76	$ 40.97
12	$ 33.08	$ 30.03	$ 40.94	$ 29.70	$ 33.75	$ 25.22	$ 25.98	$ 35.94	$ 25.25	$ 38.89	$ 47.22	$ 37.96
13	$ 29.96	$ 26.95	$ 37.54	$ 29.13	$ 35.67	$ 29.26	$ 29.23	$ 42.21	$ 29.07	$ 38.18	$ 41.85	$ 35.35
14	$ 27.95	$ 25.34	$ 35.14	$ 29.09	$ 38.22	$ 32.88	$ 31.62	$ 49.00	$ 33.46	$ 38.61	$ 38.33	$ 32.24
15	$ 26.26	$ 24.48	$ 33.37	$ 29.43	$ 42.32	$ 36.13	$ 33.48	$ 51.33	$ 35.54	$ 39.31	$ 37.23	$ 31.50
16	$ 24.63	$ 22.83	$ 30.97	$ 28.90	$ 45.06	$ 37.49	$ 35.70	$ 52.55	$ 35.67	$ 38.93	$ 34.56	$ 30.01
17	$ 24.65	$ 22.57	$ 29.82	$ 28.59	$ 46.02	$ 38.68	$ 42.26	$ 58.99	$ 37.24	$ 39.65	$ 33.09	$ 29.39
18	$ 26.44	$ 23.20	$ 29.33	$ 29.96	$ 48.14	$ 38.13	$ 41.26	$ 56.91	$ 36.80	$ 41.05	$ 39.62	$ 34.12
19	$ 35.04	$ 26.79	$ 32.45	$ 29.39	$ 45.96	$ 35.81	$ 37.74	$ 52.51	$ 32.86	$ 38.26	$ 53.28	$ 42.46
20	$ 34.88	$ 34.34	$ 37.30	$ 27.70	$ 42.70	$ 32.27	$ 32.35	$ 49.60	$ 30.16	$ 41.69	$ 47.44	$ 37.02
21	$ 31.83	$ 29.33	$ 42.21	$ 32.06	$ 39.76	$ 28.40	$ 28.70	$ 44.49	$ 29.32	$ 43.26	$ 44.68	$ 38.44
22	$ 31.41	$ 28.53	$ 39.11	$ 39.43	$ 43.11	$ 25.06	$ 23.58	$ 39.85	$ 25.44	$ 35.76	$ 44.69	$ 39.24
23	$ 28.93	$ 27.03	$ 34.52	$ 28.37	$ 36.06	$ 22.88	$ 21.25	$ 33.99	$ 21.68	$ 31.49	$ 39.88	$ 36.13
24	$ 27.26	$ 24.12	$ 30.00	$ 22.59	$ 31.02	$ 19.28	$ 18.65	$ 29.30	$ 19.77	$ 27.16	$ 35.37	$ 32.47

The simple average price per hour by month of the energy price to obtain energy for load used in Staff's production modeling is provided in the table below. Red shading indicates hours in which the average price is at or above 75% of the observed average highest price:

Hour	January	February	March	April	May	June	July	August	September	October	November	December
1	$ 29.99	$ 22.22	$ 21.66	$ 20.04	$ 20.87	$ 18.55	$ 19.24	$ 23.52	$ 17.20	$ 23.19	$ 26.72	$ 26.90
2	$ 30.27	$ 23.00	$ 23.18	$ 20.84	$ 19.39	$ 17.12	$ 17.85	$ 22.61	$ 17.12	$ 23.25	$ 26.17	$ 27.44
3	$ 29.87	$ 22.48	$ 22.98	$ 19.51	$ 17.36	$ 15.43	$ 16.52	$ 21.10	$ 15.03	$ 22.18	$ 25.75	$ 26.84
4	$ 29.69	$ 22.58	$ 22.81	$ 19.65	$ 16.83	$ 14.41	$ 15.79	$ 20.31	$ 13.91	$ 21.77	$ 25.86	$ 26.88
5	$ 30.04	$ 22.86	$ 23.29	$ 19.61	$ 16.70	$ 13.95	$ 15.23	$ 19.74	$ 13.46	$ 21.30	$ 25.91	$ 26.99
6	$ 30.67	$ 23.92	$ 24.55	$ 21.01	$ 17.30	$ 14.16	$ 15.54	$ 19.99	$ 14.19	$ 21.88	$ 27.52	$ 28.50
7	$ 33.91	$ 26.35	$ 28.54	$ 24.00	$ 19.68	$ 15.76	$ 16.45	$ 21.32	$ 16.50	$ 23.99	$ 31.42	$ 31.91
8	$ 39.50	$ 31.87	$ 35.99	$ 31.15	$ 22.37	$ 16.87	$ 17.20	$ 23.17	$ 18.77	$ 29.46	$ 40.76	$ 38.06
9	$ 40.90	$ 30.85	$ 35.82	$ 31.63	$ 25.23	$ 19.60	$ 19.09	$ 24.46	$ 19.26	$ 29.77	$ 40.34	$ 39.36
10	$ 38.10	$ 30.02	$ 34.62	$ 32.34	$ 28.08	$ 22.49	$ 22.12	$ 27.39	$ 20.92	$ 30.43	$ 38.54	$ 38.42
11	$ 38.98	$ 31.69	$ 35.07	$ 33.15	$ 28.93	$ 24.40	$ 24.68	$ 29.93	$ 22.68	$ 33.09	$ 39.26	$ 37.94
12	$ 36.06	$ 28.64	$ 32.57	$ 31.73	$ 30.40	$ 27.82	$ 28.70	$ 33.43	$ 25.81	$ 34.92	$ 36.29	$ 34.83
13	$ 32.92	$ 26.32	$ 30.71	$ 31.07	$ 32.37	$ 31.92	$ 32.50	$ 38.52	$ 30.35	$ 36.43	$ 33.46	$ 32.28
14	$ 30.62	$ 24.53	$ 29.35	$ 30.87	$ 35.13	$ 36.47	$ 35.79	$ 43.46	$ 35.42	$ 38.11	$ 31.49	$ 29.79
15	$ 29.07	$ 23.85	$ 28.56	$ 31.09	$ 38.55	$ 39.07	$ 37.87	$ 46.53	$ 38.85	$ 39.59	$ 30.86	$ 28.94
16	$ 27.77	$ 22.71	$ 27.84	$ 30.55	$ 41.09	$ 41.16	$ 39.91	$ 49.55	$ 40.85	$ 40.06	$ 29.72	$ 28.21
17	$ 27.56	$ 22.34	$ 27.05	$ 30.43	$ 42.33	$ 43.58	$ 44.77	$ 55.21	$ 44.56	$ 40.98	$ 29.39	$ 27.54
18	$ 28.96	$ 22.68	$ 27.08	$ 30.92	$ 44.15	$ 44.35	$ 44.45	$ 53.59	$ 43.96	$ 41.66	$ 32.20	$ 30.80
19	$ 38.14	$ 25.34	$ 28.48	$ 31.08	$ 42.22	$ 41.41	$ 40.49	$ 48.37	$ 38.83	$ 38.81	$ 40.83	$ 40.39
20	$ 38.03	$ 31.92	$ 32.26	$ 30.31	$ 38.36	$ 37.40	$ 36.09	$ 44.05	$ 33.91	$ 39.49	$ 37.86	$ 36.16
21	$ 36.24	$ 28.15	$ 35.91	$ 33.02	$ 34.77	$ 32.68	$ 32.98	$ 39.24	$ 31.51	$ 41.94	$ 35.94	$ 36.24
22	$ 36.60	$ 27.53	$ 34.65	$ 39.05	$ 36.48	$ 29.11	$ 28.13	$ 35.75	$ 27.55	$ 35.28	$ 35.21	$ 36.19
23	$ 34.29	$ 25.93	$ 30.09	$ 30.43	$ 30.49	$ 25.98	$ 25.10	$ 30.99	$ 22.56	$ 29.57	$ 32.38	$ 33.47
24	$ 32.52	$ 24.17	$ 26.40	$ 24.98	$ 25.19	$ 22.11	$ 21.68	$ 26.71	$ 19.89	$ 26.19	$ 29.22	$ 30.49

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

A. Production and Market Participation Related Costs

The Regulatory Assistance Project ("RAP"), has published a handbook "Electric Cost Allocation for a New Era," by Jim Lazar, Paul Chernick and William Marcus, edited by Mark LeBel, attached as Appendix 3, Schedule SLKL-d2. Staff continues to review the handbook, which addresses many of the concerns Staff has raised in recent filings. As stated in the handbook, its intent is to "both describe[] the current best practices that have been developed over the past several decades and point[] toward needed innovations. The authors of this manual believe strongly that charting a new path forward on cost allocation is an important part of creating the fair, efficient and clean electric system of the future." Staff's implementation of the methods included in this handbook as well as the methods employed by Staff in other cases was hindered by the unavailability of data. Empire's peak data, which is the basis to a greater or lesser extent to the vast majority of the costs allocated in a CCOS did not appear reasonable. Staff has had significant difficulty in producing reasonable peak data and hourly loads from the data Empire had available. Going forward, Staff recommends Empire employ more detailed data collection and retention for establishing hourly loads by rate schedule, particularly leveraging AMI meters for 100% load sampling, if applicable.[24]

Staff studied the following rate classes:

1) "Residential " - Residential Service
2) "CB/SH"[25] – Commercial Service and Small Heating Service
3) "GP/TEB"- General Power Service and Total Electric Building Service
4) "LPS" - Large Power Service

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[24] Staff's specific recommendations are provided in Section VI. B., C. and D. of this Report. As discussed at page 64 of the RAP handbook, loading information of distribution system components is an emerging determinant.

[25] As discussed in the section concerning Staff's recommended RSM implementation, these schedules include a relatively small number of customers which are responsible for a relatively high percentage of the class's load, and which should presumably be migrated to the GP/TEB class. This would shift both revenues and cost responsibility in a manner that is not readily studied.

5) "Feed & Grain"[26] – Feed Mill and Grain Elevator Service, Schedule PFM

6) Contract Transmission[27] - Special Transmission Service[28]

7) Lighting – Schedules SPL, PL, LS, MS, and other derivative schedules.

Factors to consider in determining the appropriate production-related methodology are: (1) availability of data, (2) Empire's participation in the SPP integrated energy market, (3) the lack of a liquid SPP capacity market, (4) Empire's overall gross capacity position, and, (5) the suitability of Empire's generation fleet to serve its retail load in the absence of an energy market.

While Staff has historically performed a method developed in-house referred to as the Detailed Base Intermediate Peak, this method is data intensive and Staff was unable to compile the necessary information to accommodate the timing of this direct filing. In its recent filing in Case No. ER-2019-0335, Staff offered a functionalized approach that recognized the MISO capacity market, and the overall size and makeup of the Ameren Missouri generation fleet relative to the requirements of its retail load. Given the lack of a liquid SPP capacity market, and Empire's diversified generation fleet that is generally consistent with its retail demands, as well as the direction provided by the recently-published RAP handbook,[29] for Empire Staff recommends use of a "highest hours" method discussed in the RAP handbook.[30] This method also mitigates Staff's concerns with the reliability of the hourly load data, as less emphasis is placed on the reliability of a relatively small number of hours than would occur using more simplistic traditional capacity allocation methods.

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[26] Staff imputed the Feed & Grain hourly shape based on the GP/TEB shape, reflecting the variability of the load served on this schedule and the reality that customers could elect to time processing events different than occurred in the test period.

[27] Staff imputed the Special Contract hourly shape based on the Large Power shape, reflecting the variability of the load served on this schedule and the potential that the current customer receiving service pursuant to a contract rate may not be reflective of all customers electing service. This treatment is also consistent with the availability of a demand credit as applicable.

[28] Currently, no customers are served pursuant to this literal rate schedule found at tariff sheet number 13. However, the rates found at tariff sheet number 9 for "Special Transmission Service Contract: Praxair, Schedule SC-P" should be set to correspond to the recommendations stated herein for tariff sheet number 13.

[29] Section 9.3 of the RAP handbook discusses the allocation of demand-related generation costs.

[30] See page 131, "If data are not available for a comprehensive loss-of-energy expectation analysis, a demand allocator based on all hours within a specified percentage of the peak (e.g., 80% to 95%) or based on a significant number of the highest hours in the year (e.g., 100) is preferable to a coincident peak analysis."

Staff analyzed the usage by class as a percentage of total usage for the 100 highest hours of system loading, hours within 80% of peak, 85% of peak, 90% of peak, and 95% of peak. The resulting percentages, as well as the number of hours at which the indicated percent of peak was demanded are provided in the table below, by class:[31]

		Residential	CB/SH	GP/TEB	Large Power	Feed & Grain	Contract Transmission	Lighting
Highest	**100**	48.7664%	10.3855%	26.1872%	13.4408%	0.0098%	1.1171%	0.0931%
80%	**310**	48.1597%	10.2725%	26.3679%	13.8533%	0.0098%	1.1514%	0.1854%
85%	**135**	48.5836%	10.3398%	26.2783%	13.5471%	0.0098%	1.1260%	0.1155%
90%	**51**	49.1203%	10.3220%	26.0510%	13.3171%	0.0097%	1.1069%	0.0730%
95%	**12**	50.4752%	10.4954%	25.0635%	12.8405%	0.0091%	1.0672%	0.0490%

After reviewing the above allocators for reasonableness, Staff selected the Highest 100 Hours allocator as a moderate and reliable approach.

To allocate the cost of energy to serve load, Staff relied on the load-weighted average market prices described in the preceding section.

B. Distribution Costs

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. A utility's distribution plant includes distribution substations, poles, wires, conductors, and transformers, as well as service and labor expenses incurred for the operation and maintenance of these distribution facilities. Voltage level is a factor that Staff considered when allocating distribution costs to customer classes. A customer's use or non-use of specific utility-owned equipment is directly related to the voltage level needs of the customer. All residential customers are served at secondary voltage; non-residential customers are served at secondary, primary, substation, or transmission level voltages. Prior to allocating distribution plant costs to customer rate classes, the individual distribution plant accounts are classified between customer and demand related costs. Demand-related costs are further divided between primary

[31] During the test period, and historically, Empire has had significant winter peaks.

demand reflecting customers served at primary voltage and secondary demand reflecting customers served at secondary voltage.

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 Empire's distribution system using the Zero-Intercept Cost Minimum System method. The remaining classification of Account 364 relied on Empire's 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.[32] 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.

Account 365

Staff reviewed account data and the Company's classification. Because the Company's classification did not appear unreasonable, Staff used the Company's classification.

[32] 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."

Account 366

For the underground conduit account Staff conducted a similar zero-intercept study as conducted for the distribution plant account 364. Staff found that the zero-load cost per foot was $6.33 which is close to Empire's cost of $6.90, therefore, Staff used Empire cost of $6.90 per foot to calculate the customer-related portion of plant account 366. The remaining classification of Account 366 relied upon Empire's study provided within its workpapers.

Account 367

Staff reviewed account data and the Company's classification calculation. Staff used the Company's average cost per foot of $6.47, to calculate the customer-related portion of distribution plant account 367. The remaining classification of Account 367 relied upon Empire's study provided within its workpapers.

Account 368

For line transformers account 368, Staff conducted a similar zero-intercept study as conducted for the distribution plant accounts 364 and 366 to calculate the customer-related portion.[33] The remaining classification of account 368 relied upon Empire's study provided within its workpapers.

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

Staff allocated the costs of the primary distribution facilities on the basis of the sum of each class's coincident peak demands measured at primary voltage for each month of the test period. All customers, except those served at transmission level, (i.e., primary and secondary customers), were included in the calculation of the primary distribution allocation factor, so Staff only allocated distribution primary costs to those customers that used these facilities. Staff allocated substation costs using the same allocator but with the inclusion of all customer classes.

Staff allocated the costs of the secondary distribution system, including line transformers, based on the sum of each class's coincident peak demands at secondary voltage. Consideration of load diversity is important in allocating demand-related distribution costs

[33] In response to Staff's data request Empire provided limited information concerning the sizes of transformers. Staff relied on this limited information given the lack of more robust data.

because the greater the amount of diversity among customers within a class or among classes, the smaller the total capacity (and total cost) of the equipment required for the utility company to meet those customers' needs. Load diversity exists when the peak demands of customers do not occur at the same time. The spread of individual customer peaks over time within a customer class reflects the diversity of the class load. Therefore, when allocating demand-related distribution costs that are shared by groups of customers, it is important to choose a measure of demand that corresponds to the proper level of diversity.

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

Staff recommends allocating service lines and meter costs using the same allocation methodology that Empire used to allocate these costs, except Staff used the number of meters installed on Empire's systems instead of the number of customers. These allocators are based on an Empire study that weights the number of installations by class and by the cost of the meter and service used to serve that class. In addition, Staff recommends using the same allocators that Empire used for allocating meter reading costs, uncollectible accounts, and customer service expense. These allocators are derived using Empire studies that directly assign the costs of meter reading, uncollectible accounts, and customer service expense to each customer class. The allocators are the fraction of total costs in these accounts assigned to each class, respectively.

Staff Expert/Witness: Robin Kliethermes

D. Energy Efficiency

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

Staff Experts/Witness: Robin Kliethermes

E. CCOS Results and Interclass Cost Responsibility Recommendation

Empire's current tariffed rates on an annualized and normalized basis produce revenues of $485 million. The temporary tax rider implemented on August 30, 2018 through Case No. ER-2018-0228 reduces this amount by approximately $17.8 million, to approximately $467.5 on an annualized and normalized basis.

In the Cost of Service Report filed on January 15, 2020, Staff determined that Empire's total cost of service is approximately $492 million, and once netted for the Empire Missouri retail jurisdictional portion of other revenues, that Empire's rate schedules should be revised to produce revenues of approximately $448.9 million, a reduction of approximately $36.4 million.[34]

Staff studied the rates of return produced by Empire's rate classes at the revenues produced by current tariffed rates, with and without the impact of the temporary tax rider as a reduction to class revenues. The results are provided below:

	Residential	CB/SH	GP/TEB	LPS	Feed & Grain	Contract Transmission	Lighting
Cost of service by class	$244,576,301	$51,072,726	$121,731,306	$64,979,733	$177,096	$5,133,300	$4,599,387
CCoS net of other revenues	$224,981,009	$46,746,697	$110,232,440	$57,878,241	$172,494	$4,543,122	$4,363,258
Revenue produced by tariffed rates	$222,592,677	$54,735,420	$128,659,792	$66,825,848	$82,171	$4,588,888	$7,817,187
Tax credit	$8,505,642	$2,059,225	$4,729,095	$2,156,806	$2,319	$156,100	$245,100
Revenue produced by tariffed rates reduced by tax credit	$214,087,035	$52,676,195	$123,930,697	$64,669,042	$79,852	$4,432,788	$7,572,087
Rate of return provided by tariffed rates	6.78%	12.83%	12.50%	12.10%	-36.17%	7.48%	30.35%
Rate of return provided with tariffed rates reduced by tax credit	5.53%	11.37%	11.12%	10.90%	-37.28%	6.30%	28.70%
$ change to tariffed rates to equalize rate of return	$ 2,388,332	$ (7,988,723)	$ (18,427,352)	$ (8,947,607)	$ 90,323	$ (45,766)	$ (3,453,929)
$ change to tariffed rates reduced by tax credit to equalize rate of return	$ 10,893,974	$ (5,929,498)	$ (13,698,257)	$ (6,790,801)	$ 92,642	$ 110,334	$ (3,208,829)
% change to tariffed rates to equalize rate of return	1.07%	-14.60%	-14.32%	-13.39%	109.92%	-1.00%	-44.18%
% change to tariffed rates reduced by tax credit to equalize rate of return	4.89%	-10.83%	-10.65%	-10.16%	112.74%	2.40%	-41.05%
% (Under) Over contribution at current tariffed rates	-1.06%	17.09%	16.72%	15.46%	-52.36%	1.01%	79.16%
% (Under) Over contribution at current rates reduced by tax credit	-4.67%	12.15%	11.92%	11.31%	-52.99%	-2.35%	69.63%

[34] Staff did not include the plug for expected changes due to true-up in this CCOS.

These results indicate that

1) The Residential class is contributing within 5% of its cost of service with its current rates net of the tax credit, but this calculation does not include the further reduction to Empire's overall revenue requirement recommended by Staff.[35]
2) The changes indicated by the study to the Feed & Grain classes to equalize rates of return would cause significant rate shock to customers receiving service on the rate, and would almost certainly result in rate switching.
3) The lighting customers as a class appear to be overcontributing to the system rate of return, but given the nature of the class it is difficult to recommend specific changes to rate elements within the various lighting schedules without significant further study.[36]
4) The CB/SH, GP/TEB, and LPS classes are overcontributing to the system rate of return.

Staff's recommended revenue requirement indicates that a decrease in the Empire revenue requirement of approximately $36.4 million annually is appropriate. The resulting revenue requirement net of offsets produced by other revenues is approximately $448.9 million. To apply this decrease to the revenue requirements of the studied classes, Staff recommends that all rate classes except Feed & Grain[37] retain the current level of revenue production, net of the temporary tax rider, and that the CB/SH, GP/TEB, and LPS rate schedules be adjusted by the following process:

1) Reduce class revenue requirements by the level of the temporary tax reduction,
2) Determine the amount of additional reduction available after the above-referenced reductions have been applied, (approximately $18.5 million at Staff's recommended revenue requirement),

[35] Typically Staff does not recommend revenue responsibility shifts for classes within a 5% plus or minus "deadband" of contribution to cost of service at an equal rate of return. This deadband is due to the inherent inaccuracy of class cost of service studies at a high level of precision in general, despite the appearance of a high level of precision in the results as presented.

[36] There is significant disagreement among experts and complications with studying lighting customers within a CCOS. Staff is not asserting that the Lighting schedules collectively are providing a significantly above-average rate of return nor has Staff evaluated the rates of return produced among the various lighting schedules.

[37] Staff recommends the Feed & Grain class revenue requirement be maintained at the level produced by current tariff rates, not reflecting a reduction associated with the temporary tax rider.

3) Further reduce the CB/SH and LPS revenue requirements by 25% each of the amount identified in step 2,

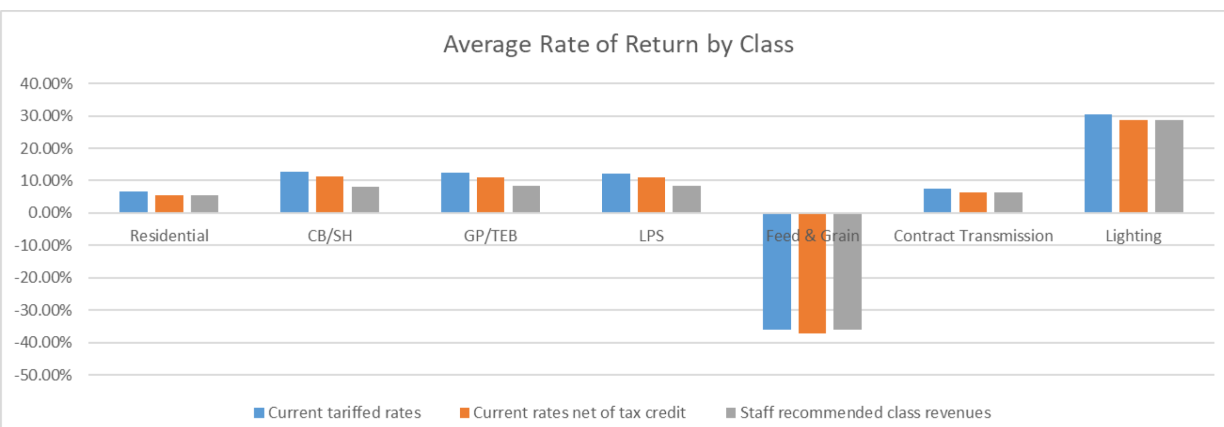
4) Further reduce the GP/TEB revenue requirements by 50% of the amount identified in step 2.

The application of this process at Staff's recommended revenue requirement is provided below:

	Residential	CB/SH	GP/TEB	LPS	Feed & Grain	Contract Transmission	Lighting
Revenue produced by tariffed rates	$222,592,677	$54,735,420	$128,659,792	$66,825,848	$82,171	$4,588,888	$7,817,187
All classes except Feed & Grain reduced to current revenue net of taxes	$214,087,035	$52,676,195	$123,930,697	$64,669,042	**$82,171**	$4,432,788	$7,572,087
SB/SH, GP/TB, and LPS receive indicated shares of remaining decrease		25%	50%	25%			
Additional reduction		$ 4,633,188	$ 9,266,377	$ 4,633,188			
Class Revenue Requirement	$214,087,035	$48,043,007	$114,664,320	$60,035,854	$82,171	$4,432,788	$7,572,087
Rate of Return produced	5.53%	8.06%	8.42%	8.33%	-36.17%	6.30%	28.70%
Reduction by class	$8,505,642	$6,692,413	$13,995,472	$6,789,994	$0	$156,100	$245,100

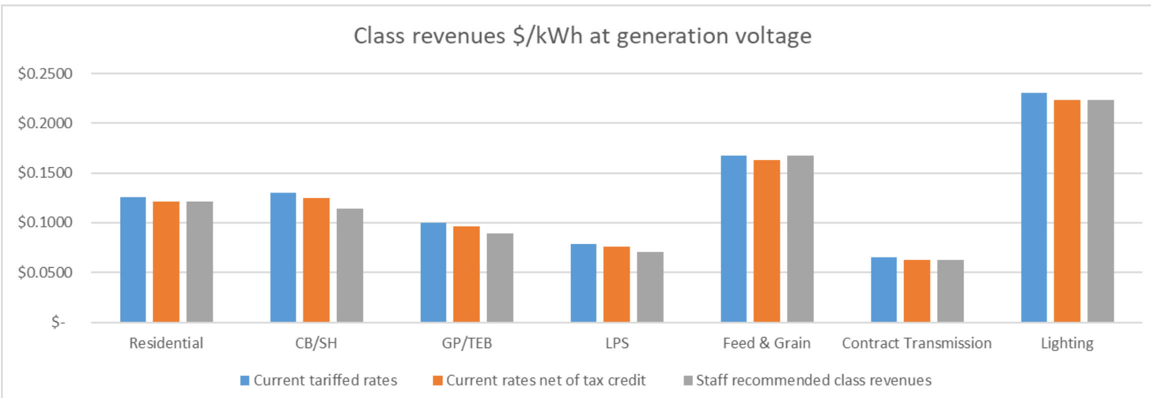
The average rate of return by class produced by current rates, current rates net of taxes, and Staff's recommended class revenues are provided in the chart and graph below:

Average Rate of Return by Class	Residential	CB/SH	GP/TEB	LPS	Feed & Grain	Contract Transmission	Lighting
Current tariffed rates	6.78%	12.83%	12.50%	12.10%	-36.17%	7.48%	30.35%
Current rates net of tax credit	5.53%	11.37%	11.12%	10.90%	-37.28%	6.30%	28.70%
Staff recommended class revenues	5.53%	8.06%	8.42%	8.33%	-36.17%	6.30%	28.70%



The class-average experienced $/kWh that results from dividing the indicated revenue level by total class-level kWh at generation are provided in the chart and graph below. Please note that these $ per kWh values are not indicative of the $/kWh experienced by any particular customer taking service within the indicated studied class.

Class revenues $/kWh at generation voltage	Residential	CB/SH	GP/TEB	LPS	Feed & Grain	Contract Transmission	Lighting
Current tariffed rates	$ 0.1261	$ 0.1301	$ 0.0997	$ 0.0788	$ 0.1676	$ 0.0651	$ 0.2306
Current rates net of tax credit	$ 0.1213	$ 0.1252	$ 0.0961	$ 0.0762	$ 0.1629	$ 0.0629	$ 0.2234
Staff recommended class revenues	$ 0.1213	$ 0.1142	$ 0.0889	$ 0.0708	$ 0.1676	$ 0.0629	$ 0.2234



Staff Expert/Witness: Sarah L.K. Lange

VI. Tariff and Other Recommendations

A. Multiple-Family Dwellings

Currently, multiple-family dwellings within a single building that are served from one meter instead of separately metered are served on the residential tariff. The customer's bill is calculated by multiplying each customer charge and kWh block by the number of dwelling units. Unless a customer obtains a variance from the Commission, multiple-family dwellings, such as apartment buildings have been required to be separately metered after June 1, 1981 according to Commission Rule 20 CSR 4240-20.050.2. However, there are buildings that were built prior to June 1, 1981 that are grandfathered and continue to be metered from one meter point. Staff suggests Empire modify its tariff to allow such master-metered customers to be served on the CB tariff instead of the Residential tariff. [38]

Staff Expert/Witness: Robin Kliethermes

[38] If existing residential customers are migrated to the CB/SH schedule an adjustment to the SRLE would be appropriate.

B. Data Retention Measures

Staff's recommends that Empire record its costs in a manner to facilitate identification of the following items:[39]

1. The cost of the primary distribution system, including relevant transformers and substations, by voltage;
2. The cost of the secondary distribution system, including relevant transformers and substations, by voltage;
3. The cost of the portions of the primary distribution system that are dedicated to serving individual customers receiving service at primary voltage, by voltage;
4. The costs of infrastructure offset by customer contributions pursuant to the line extension policy, by voltage and rate schedule;
5. The costs of meters by voltage and rate schedule.

For rights-of-way and substations that hold equipment associated with more than one voltage, as well as land, poles, or conduit that carry multiple lines, Staff recommends amounts be identified for allocation between voltages as necessary from time to time in rate cases.

C. Load Research

Staff is aware of 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 Empire include elements in its customer information systems to leverage AMI meter data with customer data – such as voltage, rate schedule, applicable voltage 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.

[39] I am not an accountant, and I am not alleging that Empire's current booking practices are inconsistent with the requirements of the USOA or any applicable accounting standards. Staff is hopeful that a cost-effective tracking system can be implemented to more accurately identify these discrete costs in the manner identified above than is possible under the current USOA major account accounting alone.

If possible, retention of load research data by circuit would be beneficial in that it may enable targeted demand response programs in the future.

D. Hourly Customer Data

To facilitate future customer selection of rate options and to estimate the impact of a transition to time-variant rate structures, Staff recommends that Empire retain the data necessary to develop a minimum of the 12 most recent months' comparison bills for customers upon installation of AMI metering.

Staff Expert/Witness: Sarah L.K. Lange

E. Energy Efficiency Recovery Charge Rates

Staff's Costs of Service filed on January 15, 2020 included a revenue requirement of approximately $2 million for Empire's non-MEEIA energy efficiency programs. Currently this revenue requirement is recovered from a separate charge referred to as Energy Efficiency Cost Recovery. Staff recommends that the non-MEEIA energy efficiency program revenue requirement be recovered from each non-lighting class based on kWh sales per class less the kWh sales from customer who have opt-out of participating in the energy efficiency programs.

Staff Expert/Witness: Robin Kliethermes

VII. Fuel and Purchased Power Adjustment Clause Tariff Sheet Recommendations

In its *Staff Report - Cost of Service* in this case, Staff's recommendations for issues impacting Empire's fuel adjustment clause ("FAC") and FAC tariff sheets included the following:

1. Continue Empire's FAC with modifications;
2. Include a revised Base Factor[40] in the FAC tariff sheets calculated from the Base Energy Cost[41] that the Commission

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

[41] Base Energy Cost is defined in Empire's Original Revised Tariff Sheet No. 17u as "Base energy cost is ordered by the Commission in the last rate case consistent with the costs and revenues included in the calculation of the Fuel and Purchased Power Adjustment ("FPA").

includes in the revenue requirement upon which it sets Empire's general rates in this case;

3. Order Empire to continue to provide monthly filings that will aid the Staff in performing FAC tariff, prudence, and true-up reviews;

4. Order Empire to include Schedule E from the Stipulation and Agreement that was approved by Commission Order in Case. No ER-2016-0023 on August 10, 2016, either within the tariff or as an attachment to the tariff, to clarify the list of sub-accounts included and excluded within the Fuel Adjustment Clause; and

5. Clarify that only transmission costs and revenues that are included in Empire's FAC are those that Empire incurs for Purchased Power and Off-System Sales.[42]

Staff indicated[43] it did not have its estimate for the Base Factor, but would provide it in its CCOS Report. Staff's method for calculating the Base Factor is shown in Appendix 2, Confidential Schedule BM-d1 of this report.

A. Fuel Adjustment Tariff Sheet Modifications

Staff reviewed the current Empire FAC tariff sheets the Commission approved in Case No. ER-2020-0093, which became effective December 1, 2019. The current FAC tariff sheets reflect Empire's participation in the Southwest Power Pool's ("SPP") Integrated Market and account for transmission costs in a manner consistent with the treatment of transmission costs in Ameren Missouri's, Evergy Missouri West's, and Evergy Missouri Metro's current FACs.

Staff proposes the following modifications to the Empire tariff:

1. Replace the current Base Factor with the revised Base Factor of $0.02216 per kWh.

2. Replace the current transmission percentage to be included in the FAC with 50% for MISO transmission costs and 32.04% for SPP transmission costs.

[42] Staff *Direct Report*, pg. 90.

[43] Staff *Direct Report*, pg. 91.

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

$VAF_{PRIM} = 1.0429$ and $VAF_{SEC} = 1.0625$

B. Revised Base Factor

Staff calculated the Base Factor of $0.02216 per kWh. This is a decrease from the current Base Factor of $0.02415 per kWh established in Case No. ER-2016-0023, which is a further decrease from the previous Base Factor of $0.02684 established in Case No. ER-2014-0351. Staff used the Base Energy Costs and Revenues from Staff's accounting, fuel model, and fuel and purchased power work papers developed in this rate case when calculating the Base Factor.

Staff will true-up its recommended Base Factor in its True-up surrebuttal testimony to be filed on March 27, 2020.

C. Revised Base Factor Calculation

Staff calculated the Base Factor of $0.02216 per kWh using the Base Energy Costs and Revenues from Staff's accounting schedules found in Staff's COS Report in this rate case. Appendix 2, Confidential Schedule BM-d1 contains Staff's calculation of the Base Factor. Components of the Base Factor calculation are fuel costs incurred to support sales, purchased power costs, native load costs, net emission allowances costs, transmission costs, net auction revenue rights and transmission congestion rights (ARR/TCR), revenues from off-system sales and renewable energy credit revenues.

Empire's fuel costs include the variable cost of fuel used in the production of electricity. Staff excluded administrative and labor expenses, which are also excluded in Empire's current FAC. In addition, Staff excluded the labor component found in other undistributed and unit train costs. Staff excluded these costs because variable fuel and purchased power expenses, as well as emission allowance expenses and off-system sales revenues are designed to flow through Empire's FAC, not administrative and labor expenses. The amount of fuel costs incurred to support sales found in Staff's accounting and fuel and purchased power workpapers, was used in the Base Factor calculation.

Staff's Base Factor calculation includes the purchased power energy costs from long term purchased power agreements ("PPAs") for energy from the Plum Point, Elk River, and Meridian facilities. Purchased power energy costs also includes variable Operations and Maintenance ("O&M") cost from the 50 MW Plum Point contract.

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

Transmission costs used to transmit energy from non-company sources to Empire's service territory are included in the FAC. These costs are developed using Staff's accounting and fuel model summary work papers. Staff calculated the percentage of MISO transmission service costs to be 50% and SPP transmission service costs to be 32.04%. Staff excluded SPP Schedule 1-A, Tariff Administration Service, and SPP Schedule 12, FERC Assessment Charge from its Base Factor calculation. These charges are excluded in the current FAC tariff sheets and are administrative costs, not variable fuel and purchased power costs.

As described above, Staff also included in its Base Factor calculation auction revenue rights and transmission congestion rights as components of Empire's FAC and are included in the Base Factor calculation. The amount is found in Staff accounting work papers.

The amount of Renewable Energy Credit Revenues found in Staff's accounting work papers was used in the Base Factor calculation. Energy from Empire's generation resources is sold into the SPP's Integrated Market. Revenue from Off-System Sales is taken from Staff's fuel model summary work papers.

D. Revised FAC Voltage Adjustment Factors

As provided in *Staff's Report - Cost of Service*, filed in this case, Staff witness Alan J. Bax used the information in Empire's line loss study to develop the following primary and secondary voltage level adjustment factors:[44]

Voltage Level	Voltage Adjustment Factor
Primary	1.0429
Secondary	1.0625

These voltage adjustment factors adjust for energy losses in the delivery of electricity from the generator to customers at primary and secondary voltage levels. Staff will use these

[44] Staff *Direct Report*, pg. 100.

factors to determine Fuel Adjustment Rates (FARs) on the FAC tariff sheets for the two voltage service levels.

Staff Expert/Witness: Brooke Mastrogiannis

VIII. Energy Efficiency

A. Commercial and Industrial Custom Rebate Program

In Case No. EW-2019-0351, Staff was ordered to file a report regarding the creation and administration of Empire's Commercial & Industrial Custom Rebate Program ("C&I Custom Rebate Program") after Commissioner Rupp was informed in April 2019 that Empire had denied a customer's application under Empire's C&I Custom Rebate Program. The customer had contacted Empire to apply for its C&I Custom Rebate Program after the customer had hired an electrician to replace several light bulbs and fixtures with LED bulbs and fixtures. Empire denied the customer's application due to the C&I Custom Rebate Program requiring the customer receive preapproval from Empire before starting the project. The customer asked Empire for a variance from the preapproval requirement and to accept them into the program. Empire denied this request stating that the customer needed to receive preapproval prior to starting the project like it states in the C&I Custom Rebate Program tariff sheet. Staff investigated how the C&I Custom Rebate Program was created and how Empire administers its C&I Custom Rebate Program through a series of informational questions that Staff sent Empire about the program. Staff reviewed information received in Case No. EW-2019-0351 and found Empire is administering the C&I Custom Rebate Program within the guidelines outlined in the C&I Custom Rebate Program tariff sheets.

The C&I Custom Rebate Program requires preapproval prior to purchase and/or installation of equipment. The preapproval process allows both Empire and the customer to know the exact amount of a rebate per project and allows Empire to be able to accurately track the budget for the C&I Custom Rebate Program. It allows Empire and the customer to be in alignment as to what is expected from both parties before committing to the project. By preapproving applications before a project is started, Empire is able to allocate the budget accurately across multiple projects and also ensures that the customer knows the specific rebate amount it will receive. The preapproval process also allows the program implementer to perform a desk review which will help determine if the equipment qualifies for a rebate, test whether the project is cost effective, and the payback period for the customer. If a preapproval process was not in place, Empire would have a more difficult time keeping the program on budget and if a preapproval process was not in place customers could be starting projects without the assurance of getting a rebate for that project. Having a preapproval process allows Empire to accurately track the budget and allows Empire to let customers know if they will be able to receive a rebate for their project or if they will need to postpone their project for another year so it will get the rebate in the next budget year.

Staff's report for Case No. EW-2019-0351 stated it would further review the C&I Custom Rebate Program preapproval process again in Empire's next general rate which is the present case, Case No. ER-2019-0374. Staff sent additional data requests (DR Nos. 0153-0163) in this case regarding the C&I Custom Rebate Program. After reviewing the additional information from the data request responses, Staff recommends that Empire continue the preapproval process for its C&I Custom Rebate Program. In reviewing the C&I Custom Rebate Program, Staff also reviewed Empire's other Energy Efficiency programs and recommends those programs continue as currently structured.

Staff Expert/Witness: Mark Kiesling

B. LED Lighting

On March 12, 2018, Empire filed its Notice of LED Report ("Report") in Case No. ER-2012-0345. The Report concluded that the major outcome of Empire's LED pilot program was the exposure of energy efficient LED street lights to community leaders and residents. The participating communities were pleased with the performance of the LED street lights and gained valuable knowledge regarding the benefits of switching to LED street lights. The communities preferred the LED fixtures over the previously used High Pressure Sodium ("HPS") fixtures and confirmed that the LED lights provided better uniformity and quality of light on roadway surfaces while limiting glare and the unintended spill of light. The LED streetlights demonstrated much lower energy usage in comparison to HPS lights of similar lumens. In fact, Empire found that the LED lights used less than half of the kWh used by lights over the course of a year during the pilot program. The Report also stated that Mercury vapor ("MV") light bulbs are still available, however, the MV fixtures are not still available in the market. LED lights are more energy efficient than MV lights, have reduced maintenance costs, have a longer life, and are environmentally friendly.

Since July 27, 2018, Empire has provided Municipal Street Lighting Service[45]. Empire had researched the suitability and feasibility of deploying LED based lighting and found LED lighting was a viable option for municipalities served by Empire. The LED street lighting program was implemented after the pilot program was conducted to determine the benefits of LED lights compared to HPS fixtures. The pilot program stemmed from a Commission-approved stipulation and agreement[46].

Staff recommends the continuation of Empire's LED municipal street lighting tariff.

Staff Expert/Witness: Krishna Poudel

IX. Appendices

Appendix 1 - Staff Credentials

Appendix 2 – Brooke Mastrogiannis
(Schedule BM-d1)

Appendix 3 - Sarah L.K. Lange
(Schedule SLKL-d1 and SLKL-d2)

[45] On June 27, 2018, The Empire District Electric Company ("Empire") filed with the Missouri Public Service Commission ("Commission") two (2) revised tariff sheets for a new service under the Municipal Street Lighting Service Light Emitting Diode ("LED") Tariff Schedule SPL-LED. The tariff sheets allowed Empire to initiate a LED lighting service for outdoor lighting of streets, alleys, parks, and public places of municipalities served by Empire. The tariff sheets went into effect on July 27, 2018.

[46] Commission Case No. ER-2012-0345, and the pilot tariff schedule was assigned Tracking No. JE-2015-15 0004.

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of The Empire District Electric Company's Request for Authority to File Tariffs Increasing Rates for Electric Service Provided to Customers in its Missouri Service Area	))))	Case No. ER-2019-0374

AFFIDAVIT OF MARK KIESLING

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

COMES NOW MARK KIESLING and on his oath declares that he is of sound mind and lawful age; that he contributed to the foregoing *Staff Class Cost of Service Report*; and that the same is true and correct according to his best knowledge and belief.

Further the Affiant sayeth not.

Mark Kiesling

MARK KIESLING

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 28th day of January 2020.

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 The Empire District Electric Company's Request for Authority to File Tariffs Increasing Rates for Electric Service Provided to Customers in its Missouri Service Area	))))	Case No. ER-2019-0374

AFFIDAVIT OF ROBIN KLIETHERMES

STATE OF MISSOURI	)	
	)	ss.
COUNTY OF COLE	)	

COMES NOW ROBIN KLIETHERMES and on her oath declares that she is of sound mind and lawful age; that she contributed to the foregoing *Staff 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

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 28th day of January 2020.

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 The Empire District Electric Company's Request for Authority to File Tariffs Increasing Rates for Electric Service Provided to Customers in its Missouri Service Area	))))	Case No. ER-2019-0374

AFFIDAVIT OF SARAH L.K. LANGE

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

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 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 29th day of January 2020.

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 The Empire District Electric Company's Request for Authority to File Tariffs Increasing Rates for Electric Service Provided to Customers in its Missouri Service Area	))))	Case No. ER-2019-0374

AFFIDAVIT OF BROOKE MASTROGIANNIS

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

COMES NOW BROOKE MASTROGIANNIS and on her oath declares that she is of sound mind and lawful age; that she contributed to the foregoing *Staff 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.

Brooke Mastrogiannis
BROOKE MASTROGIANNIS

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 28th day of January 2020.

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 The Empire District Electric Company's Request for Authority to File Tariffs Increasing Rates for Electric Service Provided to Customers in its Missouri Service Area	))))	Case No. ER-2019-0374

AFFIDAVIT OF KRISHNA POUDEL

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

COMES NOW KRISHNA POUDEL and on his oath declares that he is of sound mind and lawful age; that he contributed to the foregoing *Staff Class Cost of Service Report*; and that the same is true and correct according to his best knowledge and belief.

Further the Affiant sayeth not.

KRISHNA POUDEL

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 28th day of January 2020.

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