Exhibit No.: _____
Issues: Class Cost of Service Study, Rate Design, and Cash Working Capital
Witness: Timothy S. Lyons
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Before the Public Service Commission
of the State of Missouri

Direct Testimony

of

Timothy S. Lyons

on behalf of

The Empire District Electric Company

May 2021

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THE EMPIRE DISTRICT ELECTRIC COMPANY
BEFORE THE MISSOURI PUBLIC SERVICE COMMISSION
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DIRECT TESTIMONY OF TIMOTHY S. LYONS
THE EMPIRE DISTRICT ELECTRIC COMPANY
BEFORE THE MISSOURI PUBLIC SERVICE COMMISSION
CASE NO. ER-2021-0312

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Timothy S. Lyons. My business address is 1900 West Park Drive, Suite 250, Westborough, Massachusetts, 01581.

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

A. I am a Partner at ScottMadden, Inc. ("ScottMadden").

Q. On whose behalf are you testifying in this proceeding?

A. I am testifying on behalf of The Empire District Electric Company ("Empire" or "Company").

Q. Please describe your professional and educational experience.

A. I have more than 30 years of experience in the energy industry. I started my career in 1985 at Boston Gas Company, eventually becoming Director of Rates and Revenue Analysis. In 1993, I moved to Providence Gas Company, eventually becoming Vice President of Marketing and Regulatory Affairs. Starting in 2001, I held a number of management consulting positions in the energy industry, first at KEMA and then at Quantec, LLC. In 2005, I became Vice President of Sales and Marketing at Vermont Gas Systems, Inc. before joining Sussex Economic Advisors, LLC ("Sussex") in 2013. Sussex was acquired by ScottMadden in 2016.

I hold a bachelor's degree from St. Anselm College, a master's degree in Economics from The Pennsylvania State University, and a master's degree in Business Administration from Babson College.

Q. Have you previously testified before the Missouri Public Service Commission ("Commission") or any other regulatory agency?

A. Yes. My testimony experience is included in **Schedule TSL-1**.

Q. What is the purpose of your Direct Testimony?

A. The purpose of my testimony is to sponsor the proposed electric rates for Empire's Missouri jurisdiction. My Direct Testimony includes: (a) a description of the current rate classes; (b) development of the allocated or Class Cost of Service Study ("CCOS"); (c) development of the proposed revenue targets, rate design, and bill impact analyses for each rate class; and (d) development of the lead-lag study used to determine the Company's cash working capital requirement.

Q. Have you prepared schedules to support this testimony?

A. Yes. **Schedules TSL-2 through TSL-11** summarize the results of the CCOS, rate design proposals, and Cash Working Capital requirement. These Schedules were prepared by me or under my direction.

II. OVERVIEW

Q. Please summarize your Direct Testimony.

A. The results of the Company's CCOS show that the current rate design produces a disparity in class rates of return ("ROR"). The Residential General ("RG"), Miscellaneous Service ("MS"), Municipal Street Lighting ("SPL"), and Special Lighting ("LS") rate classes produce RORs that are less than the system or overall ROR, indicating their rates recover less than their cost of service. The remaining commercial and industrial ("C&I") and Lighting rate classes produce RORs that are more than the system ROR, indicating their rates recover more than their cost of service. Except as described in this testimony, the CCOS was prepared consistent with the methodologies used in the Company's 2019 rate case filing (ER-2019-0374).

The results of the CCOS support a movement toward a more equitable rate structure where class RORs move closer to the system ROR. However, the proposed movement to the system ROR was subject to certain limitations to address customer bill impact considerations.

The proposed rate design reflects improved alignment between monthly customer charges and customer-related costs and billing demand charges and billing-related costs.

The Company prepared a bill impact analysis to evaluate the impact of the proposed base rate changes. The bill impact analysis evaluated a wide range of customer usage. The bill impact analysis was prepared in two ways:

1. Proposed Base Rates vs. Current Base Rates, comparing (i) the proposed base rates, and (ii) the current base rates; and
2. Proposed Total Bill vs. Current Total Bill, comparing (i) the proposed base rates plus the Energy Efficiency Cost Recovery ("EECR") charge and Winter Storm Uri charge, and (ii) the current base rates plus the EECR charges and Winter Storm Uri charge.

Overall, the proposed base rates will increase a monthly bill for a Residential General customer using 1,000 kWh per month by $12.76 per month. [1]

The proposed base rates reflect three important rate design principles: (a) rates should recover the overall cost of providing service; (b) rates should be fair, minimizing inter- and intra-class inequities to the extent possible; and (c) rate changes should be tempered by rate continuity concerns.

Q. Did the Company evaluate the CCOS and rate design proposals by other intervenor parties in the Company's most recent rate proceeding (Case No. ER-2019-0374)?

A. Yes, the Company evaluated CCOS and rate design proposals by Commission Staff ("Staff") and Midwest Energy Consumers Group ("MECG") in Case No. ER-2019-0374.

1. In preparation of the CCOS study, the Company:
    a. Evaluated the allocation of production-related costs proposed by Staff and MECG in the prior case.
    b. Revised its classification of distribution plant accounts 364 and 366 to reflect the zero-intercept study proposed by Staff.[2]
    c. Evaluated the allocation of primary and secondary distribution plant facilities proposed by Staff and MECG in the prior case.[3]
    d. Firmed-up interruptible revenues to properly match with cost allocation of all fixed production plant, as proposed by MECG in the prior case.
2. In preparation of the rate design for this case, the Company:

[1] Based on a monthly bill for a Residential General customer using 1,000 kWh per month, including EECR of $0.00045 per kWh and Storm Uri charge of $0.00708 per kWh.
[2] ER-2019-0374 Staff CCOS Report, p. 27-29.
[3] ER-2019-0374 Staff CCOS Report, p. 29; Direct Testimony of Kavita Maini, p. 22-23

a. Evaluated consolidation of customer charge, head block and summer tail block rates for Schedules CB and SH, while maintaining distinct tail block rates for each schedule, as proposed by Staff in the prior case.[4]

b. Evaluated consolidation of Schedules General Power ("GP") and Total Electric Building ("TEB"), as proposed by Staff in the prior case.[5]

Evaluated consolidation of Schedules Feed Mill and Grain Elevator Service ("PFM") with Schedules CB and SH. While Staff proposed consolidation of Schedule PFM with Schedules GP and TEB,[6] the Company evaluated consolidation with Schedules CB and SH as these rate schedules are similar in rate structure and class cost of service to PFM.

Q. Please briefly describe Empire's service area.

A. Empire is a regulated utility providing electric service in parts of Missouri, Kansas, Oklahoma, and Arkansas. In the Missouri jurisdiction, the Company provides electric service to residential, C&I, and street lighting customers. The Company serves approximately 157,958 electric customers in Missouri, including 133,243 (84.4 percent) residential customers, 24,341 (15.4 percent) C&I customers, and 374 (0.2 percent) lighting customers.

Customers are presently served under one of twelve rate classes based on type of service and load characteristics. The rate classes consist of one Residential class, eight C&I classes, and three Lighting classes. Current rates, excluding lighting classes, are shown in Figure 1 (below).

[4] ER-2019-0374 Staff CCOS Report, p. 16.
[5] Id., p. 18.
[6] Id., p. 20.

Figure 1: Current Rate Structure

Empire District Electric (MISSOURI) Summary of Rates	Residential General RG	Commercial Service CB	Small Heating SH	General Power GP	PRAXAIR Contract SC-P	Total Electric Building TEB	Feed Mill Grain Service PFM	Large Power LP
Current Rates								
Customer Charge	$ 13.00	$ 22.69	$ 22.69	$ 69.49	$ 259.01	$ 69.49	$ 27.65	$ 283.55
kWh Charge - Winter								
1st Block kWh Charge	0.12535	0.12712	0.12441	0.07464	0.03614	0.07897	0.17527	0.05778
2nd Block kWh Charge	0.10093	0.11377	0.09172	0.06078	-	0.06324	0.15871	0.03270
3rd Block kWh Charge				0.06027	0.02956	0.06197		
kWh Charge - Summer								
1st Block kWh Charge	0.12535	0.12712	0.12441	0.08694	0.05198	0.10453	0.17527	0.06543
2nd Block kWh Charge	0.12535	0.12712	0.12441	0.06745	0.04150	0.08098	0.17527	0.03400
3rd Block kWh Charge				0.06056	0.03147	0.07286		
Facility Demand kW				$2.07	0.50	2.13		1.88
Billed Demand kW				$5.71	17.10	2.88		8.66
Facility Demand kW				$2.07	0.50	2.13		1.88
Billed Demand kW				$7.33	25.16	3.50		15.69

Q. Please describe the Company's current rate structure.

A. The Company's current rate structure includes base rates, a FAC factor, and an EECR charge.[7] The base rates include monthly customer charges, energy (kWh) charges, and demand (kW) charges. For certain rate classes, the energy charges vary by season and consist of declining rate steps or blocks; i.e., the rates decrease as monthly consumption increases. For example, the energy charges for the RG class vary by winter (October through May) and summer (June through September) seasons. In addition, the first 600 kWh of monthly energy consumption during the winter season (i.e., first rate block) is charged $0.12535 per kWh while consumption greater than 600 kWh (i.e., second rate block) is charged $0.10093 per kWh. The current base rates took effect on September 16, 2020.

[7] The Company's tariffs are available at: https://www.empiredistrict.com/CustomerService/Rates/Electric/MO.

Q. Please describe the Company's rate classes.

A. Figure 2 (below) provides a breakdown of test year customers and kWh sales by rate class. The test year represents the period October 1, 2019 through September 30, 2020. The usage in Figure 2 has been normalized for weather.

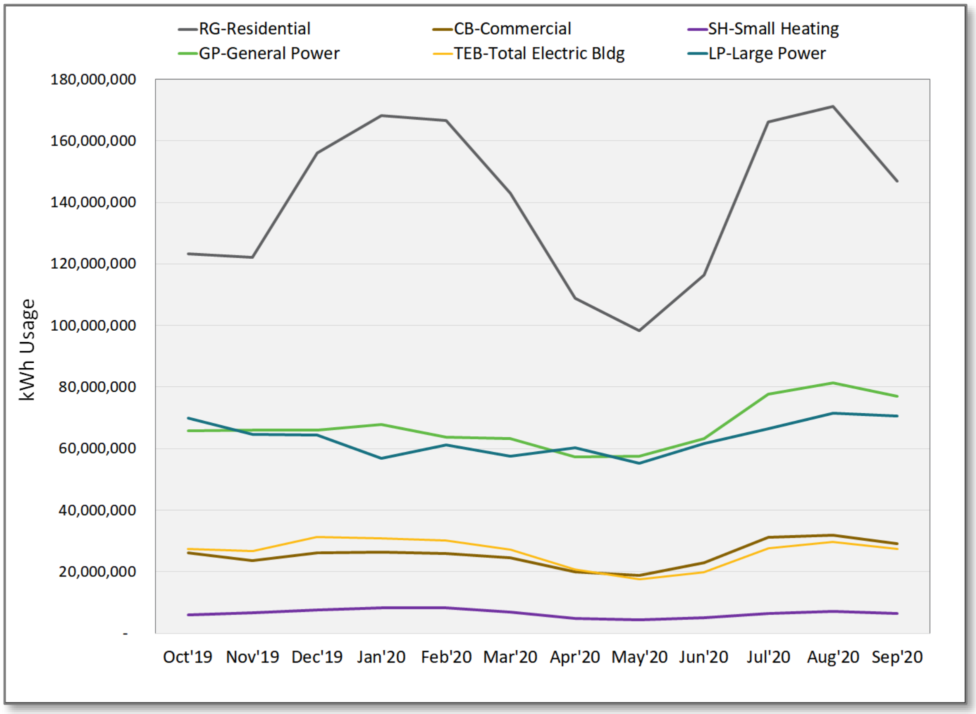
Figure 2: Test Year Customers and Sales

Rate Class	Number of Customers	% of Customers	Sales kWh	% of Sales	kWh Usage per Customer
RG-Residential	133,243	84.4%	1,672,672,383	39.6%	12,554
CB-Commercial	18,355	11.6%	314,901,557	7.5%	17,156
SH-Small Heating	3,196	2.0%	79,755,494	1.9%	24,954
GP-General Power	1,804	1.1%	837,325,668	19.8%	464,149
SC-P PRAXAIR Transmissio	1	0.0%	69,477,754	1.6%	69,477,754
TEB-Total Electric Bldg	932	0.6%	340,335,347	8.1%	365,167
PFM-Feed Mill/Grain Ele\	10	0.0%	452,711	0.0%	45,652
LP-Large Power	43	0.0%	874,735,928	20.7%	20,370,297
MS-Miscellaneous	2	0.0%	136,106	0.0%	62,818
SPL-Municipal St Lighting	6	0.0%	17,854,334	0.4%	3,060,743
PL-Private Lighting	245	0.2%	12,566,733	0.3%	51,380
LS-Special Lighting	122	0.1%	405,972	0.0%	3,332
Total	157,958	100.0%	4,220,619,987	100.0%	26,720
Residential	133,243	84.4%	1,672,672,383	39.6%	12,554
C&I	24,343	15.4%	2,517,120,565	59.6%	103,402
Lighting	372	0.2%	30,827,039	0.7%	82,813

The Figure shows the RG class represents a majority of the Company's customers. The Figure also shows variations in annual use per customer among the rate classes. RG customers, for example, use on average 12,554 kWh per year, while Large Power customers use on average 20,370,297 kWh per year.

Figure 3 (below) shows monthly kWh sales by rate class throughout the year. The Figure shows sales vary seasonally for certain rate classes.

Figure 3: Monthly kWh Sales by Rate Class



The RG rate class, for example, shows a seasonal load pattern, with monthly sales increasing during the winter and summer months, reflecting heating and cooling use, respectively. The C&I rate classes show relatively consistent load patterns throughout the year, with slight increases during the summer months in some cases. The load pattern differences, as discussed below, have implications on the allocation of costs in the CCOS.

III. ALLOCATED COST OF SERVICE STUDY

Q. Please describe the purpose of a CCOS.

A. The purpose of a CCOS is to allocate a utility's overall cost of service to each rate class in a manner that reflects its underlying cost of service. The CCOS sponsored in this testimony was developed by identifying the relationship between the service requirements for each rate class and their respective cost drivers. This approach is well established in industry literature[8] and is consistent with the methodologies described in the Company's prior rate cases, Case No. ER-2014-0351 and Case No. ER-2019-0347.

Q. Please describe the approach used to develop the CCOS for this case.

A. The CCOS study was based on three steps. First, costs were functionalized or assigned into one of five functional categories: production, transmission, primary distribution, secondary distribution, and customer service. Next, functionalized costs were classified into one of three cost drivers: whether costs are related to serving peak demands, providing energy, or meeting customer service requirements. Finally, classified costs were allocated to each rate class based on a set of methods that best represents how costs are incurred.

Each of the three steps was performed using two types of assignments: direct assignment and indirect assignment. Direct assignments utilized the Company's financial data, knowledge of its system, and special studies to assign plant investments and expenses to certain functions, classifications and rate classes. Indirect assignments utilized composite allocators based on direct and indirect assignments developed during the functionalization, classification and allocation process. A description of the functional factors, classifiers and allocators is included in **Schedule TSL-3**.

Q. What is functionalization?

A. Functionalization is the process of assigning rate base and expense items into four operational components, including production, transmission, distribution, and customer service.

[8] See Principles of Public Utility Rates by James C. Bonbright.

Q. How were costs functionalized for the CCOS?

A. The functionalization of costs in this study was generally based on accounting data arranged by the Federal Energy Regulatory Commission's ("FERC") Uniform System of Accounts ("USOA"). Generation plant and associated costs were functionalized into production accounts and allocated based on demand and energy allocators. Transmission plant and associated costs were functionalized into transmission accounts and allocated based on demand allocators. Distribution facilities and associated costs were functionalized into primary and secondary distribution since certain customers take service from only the primary distribution system while other customers take service from the secondary distribution system.

Q. What is classification?

A. Classification is the process of assigning rate base and expense items into categories that reflect cost-causation. There are three principle causes or drivers of costs related to the electric system: (a) Customer-related, costs that vary with the number of customers, such as costs associated with connecting customers to the electric system and providing basic customer services, such as metering and billing; (b) Demand-related, costs that vary with maximum customer demands at the time of the system peak, at the time of the rate class peak, or at the time of the customer peak; and (c) Energy-related, costs that vary with the production, transmission and delivery of energy, such as fuel and purchased power expenses.

Q. What is allocation?

A. Allocation consists of assigning rate base and expense items to individual rate classes based on allocators that reflect their underlying cost of service.

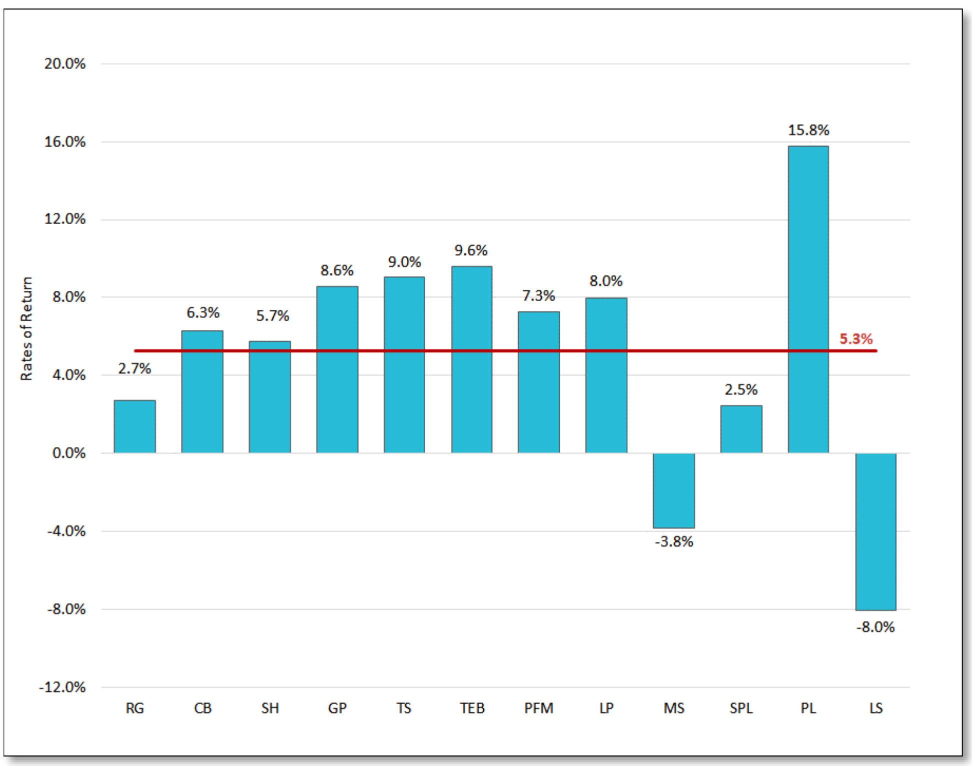
Q. Earlier, you described the approach used to develop the CCOS for this case. How, specifically, was the CCOS study developed?

A. The CCOS study was based on a spreadsheet model developed by ScottMadden for this filing. Each rate base and expense item in the CCOS study was assigned to each rate class in Figure 1 based on the three-step process described above.

Q. Please describe the overall results of the Company's cost of service study.

A. The results of the CCOS are shown in Figure 4 (below). The Figure compares the calculated ROR for each rate class (based on current rates) to the system or overall ROR.

Figure 4: Class vs. Overall Rates of Return at Current Base Rates

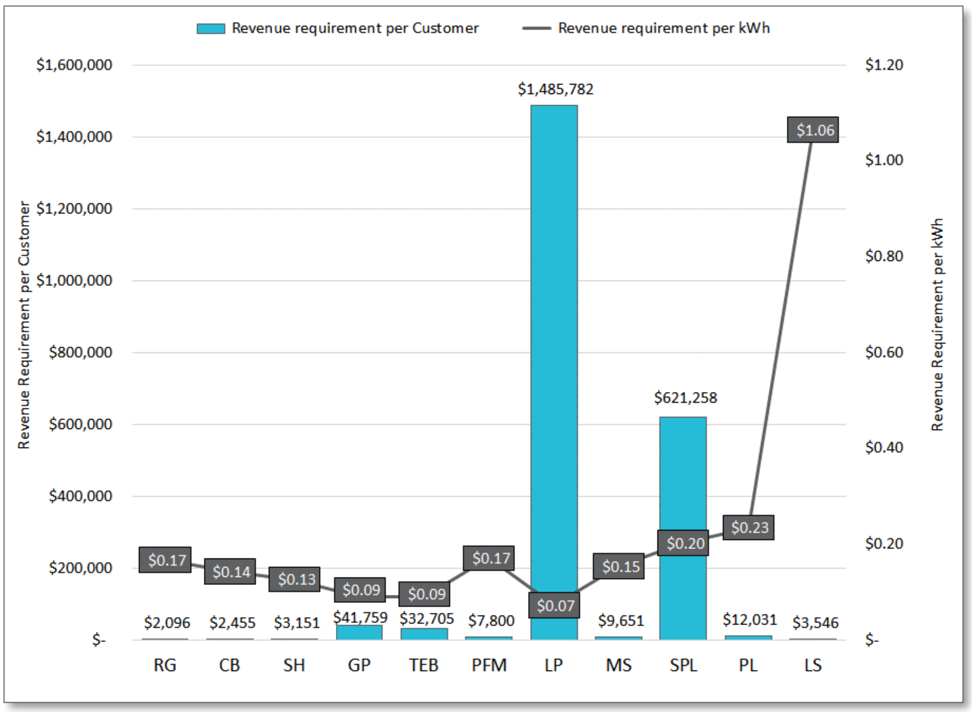


The Figure shows the Company's Residential General ("RG"), Miscellaneous Service ("MS"), Municipal Street Lighting Service ("SPL"), and Special Lighting ("LS") rate classes produce a ROR below the system ROR. The C&I and remaining Lighting rate classes produce a ROR above the system ROR. Further details are included in **<u>Schedule TSL-3</u>**.

Q. Does the cost of service vary across the Company's rate classes?

A. Yes, the cost of service per customer and per kWh (i.e., the unit cost of service) varies across the Company's rate classes, as shown in Figure 5 (below).

Figure 5: Unit Cost of Service by Rate Class[9]



The Figure shows, for example, the unit cost of service for the Residential General ("RG") rate class is $2,096 per customer, while the unit cost of service for the Large Power ("LP") rate class is $1,485,782 per customer. By comparison, the unit cost of service for the Residential General ("RG") class is $0.17 per kWh, while the unit cost of service for the Large Power ("LP") rate class is $0.07 per kWh.

[9] For confidentiality purpose, TS rate class average cost of service is not shown in this testimony.

Q. How do variations in the unit cost of service relate to the class rates of return?

A. Variations in the unit cost of service support the need for separate classes since a rate that is equal to the unit cost of service produces a ROR for each rate class that is equal to the system ROR.

Q. What conclusions can be reached when a rate class ROR is higher or lower than the system ROR?

A. If a rate class produces a ROR that is lower than the system ROR, then the revenues recovered from the rate class are less than its cost of service. Conversely, if a rate class produces a ROR that is higher than the system ROR, then the revenues recovered from the rate class are more than its cost of service. As discussed below, the CCOS study results were used as a guide to establish revenue targets for each rate class, subject to bill continuity concerns, that move the Company's proposed rates in aggregate closer to the system ROR to achieve more fair and equitable rates across customer classes.

Q. Please describe the data used to prepare the CCOS.

A. The CCOS study was based on test year data for the period October 1, 2019 through September 30, 2020. The CCOS includes the number of customers, sales and revenues by rate class. Sales and revenues have been adjusted to reflect the impact of normal weather, COVID-19 impact and other factors. The CCOS also includes rate base items, including intangible plant, production, transmission, distribution and general plant-in-service as well as (a) additions to plant-in-service, including materials and supplies, prepayments, cash working capital, and other regulatory assets, and (b) reductions to plant-in-service, including accumulated deferred income taxes ("ADIT"), customer deposits, customer advances for construction, and other regulatory liabilities. The CCOS also includes operations and maintenance ("O&M") expenses, including transmission, distribution, customer service, customer account, sales, and administrative and general expenses as well as taxes other than income, such as payroll and property taxes, and income taxes.

Q. Please describe the functionalization process used in developing the CCOS.

A. As discussed earlier, functionalization is an important first step in development of the CCOS study. The functionalization process in this study generally followed the USOA. However, distribution plant was further functionalized into primary and secondary distribution facilities to ensure that the cost of service at these functional levels was separately identified and applied.

The overall cost of service was functionalized into one of the following categories:

- Production – plant investment and expenses associated with the Company's generation facilities. These include production plant, accumulated depreciation, depreciation expense, and production expenses.
- Transmission – plant investment and expenses associated with the Company's high voltage transmission facilities. These include transmission plant, accumulated depreciation, depreciation expense, and related O&M expenses.
- Primary Distribution – plant investment and expenses associated with the Company's primary voltage distribution facilities. These include primary distribution plant, accumulated depreciation, depreciation expense, and related O&M expenses. Some costs that support both the primary and secondary distribution systems were functionalized into primary and secondary functions. Such costs include poles and towers, overhead conductors and devices, underground conduit, and underground conductors and devices.

- Secondary Distribution – plant investment and expenses associated with the Company's secondary voltage distribution facilities. These include secondary distribution plant, accumulated depreciation, depreciation expense, and related O&M expenses. The secondary portion of poles and towers, overhead conductors and devices, underground conduit, and underground conductors and devices are also included in this function.
- Customer Service – expenses associated with providing customer service. These costs are largely related to customer service, customer accounts, and sales expenses.

The remaining rate base and cost of service accounts were assigned to one of five functional categories based on composite functionalization of the plant accounts. For example, general plant and labor-related administrative and general ("A&G") expenses were assigned to all five functional categories based on the composite functionalization of labor-related production, transmission, and distribution expenses. Further descriptions of the functionalization factors are included in **Schedule TSL-4**.

Q. Please describe the classification process used in developing the CCOS study.

A. The CCOS study was classified into one of the following three categories:

- Customer-related – costs associated with providing customer access to the electric system as well as providing on-going customer service, such as meter reading and billing services.
- Demand-related – costs associated with meeting customer peak demand requirements.
- Energy-related – costs associated with meeting customer energy requirements.

In some cases, costs were classified into only one of three categories. The cost of meter reading, for example, was classified as customer-related. In other cases, costs were classified into more than one category. For example, the costs associated with primary distribution plant were classified based on their underlying characteristics. Some costs were classified as customer-related, while others were classified as demand-related.

Q. Please explain the classification of distribution facilities.

A. Distribution plant represents 32.6 percent of the Company's investment in utility plant. The classification of distribution plant reflects two primary cost drivers. The first cost driver is the number of customers, i.e., distribution facilities are designed to provide customer access to the electric system. The second cost driver is peak demands, i.e., distribution facilities are designed to meet customer peak demands throughout the year. The approach to classification of distribution facilities is well-established and recognized by the National Association of Regulatory Commissioners ("NARUC"). Specifically, NARUC states:

> Distribution plant accounts 364 through 370 involve demand and customer costs. The customer component of distribution facilities is that portion of costs which varies with the number of customers. Thus, the number of poles, conductors, transformers, services and meters are directly related to the number of customers on the utility's system…each primary plant account can be separately classified into demand and customer components.[10]

The classification of distribution plant in this study is consistent with the approach described in the NARUC manual as well as the approach described in the Company's prior rate case filing (ER-2019-0374). As discussed earlier, distribution plant and related costs are separated into two functions: primary and secondary distribution. The primary

[10] NARUC Electric Utility Cost Allocation Manual, p. 90.

distribution facilities and line transformers are classified as customer- or demand-related, while Secondary distribution facilities are generally classified as customer-related.

Q. Please explain the approach used to classify primary distribution plant.

A. Distribution plant accounts were classified based on their specific functions. For distribution plant related to facilities associated with distribution substations (360-363), the plant was classified as demand and allocated to each rate class based on class Non-Coincidental Peak ("NCP") demands. Substations generally reflect the peak demands of customers served from the substation and thus can peak at times different than the system peak. The class NCP reflects peak demands of customers served from the substations.

For distribution plant related to facilities associated with overhead and underground lines (Accounts 364-368), the costs were classified as both customer and demand. The customer-related costs are allocated to each rate class based on the number of customers. The demand-related costs are allocated to each rate class based on customer peak demands.

Q. Please describe the methods to classify Accounts 364-368 costs between customer and demand.

A. There are two methods recognized in the NARUC manual for classifying Accounts 364-368 costs between customer and demand: the 'minimum-size' and 'zero-intercept' methods.

The minimum-size method represents the cost of connecting customers to the system to serve minimum demands. The minimum-size method assumes that a minimum size distribution system can be built to serve minimum demand requirements of customers. The "minimum system" costs are classified as customer-related, while distribution plant in excess of the minimum system reflect the cost of serving customer peak demands and is classified as demand-related. The approach is described in the NARUC manual:

> Classifying distribution plant with the minimum-size method assumes that a minimum size distribution system can be built to serve the minimum loading requirements of the customer. The minimum-size method involves determining the minimum size pole, conductor, cable, transformer, and service that is currently installed by the utility.[11]

The zero-intercept method represents the cost of connecting customers to the system with a hypothetical "zero size" facility. The method includes a regression analysis conducted to examine the relationship between the facility sizes and their average costs. The intercept of the regression equation represents the average cost of a hypothetical zero size facility. The "zero size" facility costs are classified as customer-related, while distribution plant in excess reflects the cost of serving customer peak demands and is classified as demand-related. The approach is described in the NARUC manual:

> The minimum-intercept method seeks to identify that portion of plant related to a hypothetical no-load or zero-intercept situation….The technique is related to installed cost to current carrying capacity or demand rating, creating 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.[12]

Q. Please describe the Company's approach to classify Accounts 364-368 costs between customer and demand in this proceeding.

A. The Company classified distribution plant for accounts 365, 367 and 368 based on using the minimum-size method and for accounts 364 and 366 based on using the zero-intercept methods. The minimum-size and zero-intercept methods utilized the Company's installed

[11] NARUC Electric Utility Cost Allocation Manual, p. 90.
[12] Id. at p. 92.

costs for each plant account adjusted for current dollars utilizing the Handy-Whitman Index of Public Utility Construction Costs ("Handy-Whitman").

Q. Please summarize the results of the zero-intercept and minimum-size studies.

A. The results of the studies are provided in **<u>Schedule TSL-5</u>**.

- Poles, Towers, and Fixtures (Account 364): The Company's minimum-size and zero-intercept studies for Account 364 resulted in, respectively, 49.1 percent and 42.0 percent of costs classified as customer-related. Since both methods are recognized by NARUC, the Company used the lower of the two results for use in the CCOS study, i.e., 42.0 percent of costs are classified as customer-related with the remaining portion classified as demand-related.
- Overhead conductors and devices (Account 365): The Company's minimum-size study for Account 365 resulted in 29.1 percent of costs classified as customer-related with the remaining portion as demand-related.
- Underground Conduits (Accounts 366): The Company's minimum-size and zero-intercept studies for Account 366 resulted in, respectively, 55.6 percent and 45.6 percent of costs classified as customer-related. Since both methods are recognized by NARUC, the Company used the lower of the two results for use in the CCOS study, i.e., 45.6 percent of costs are classified as customer-related with the remaining portion classified as demand-related.
- Underground Conductors and Devices (Accounts 367): The Company's minimum-size study for Account 367 resulted in 38.5 percent of costs classified as customer-related with the remaining portion as demand-related.

- Line Transformers (Account 368): The Company's minimum size study resulted in 42.5 percent of costs classified as customer-related with the remaining portion classified as demand-related. The Company did not have adequate supporting data to prepare a zero-intercept study for Account 368.

Q. Please discuss the classification of other rate base items.

A. Other rate base items were similarly classified based on their underlying cost drivers. For example, meter cost, meter installation and service cost investments were classified as customer-related since they enable customers access to the electric system. Rate base items not directly associated with one of the classification categories, such as intangible plant, were classified using a composite classifier based on the classification of total plant.

Q. Please discuss the classification of operations and maintenance expenses.

A. Operations and maintenance ("O&M") expenses were classified in a manner similar to their respective plant items. For example, Maintenance of line transformers (Account 595) was classified based on the classification of Line Transformers (Account 368).

O&M expense items not directly associated with one of the classification categories, such as non-labor related A&G expenses, were classified through a composite classifier based on related costs.

Q. Please describe the allocation process used in developing the CCOS study.

A. Costs were allocated to each rate class based on how costs are incurred to serve that class. In other words, for each component of cost, the Company developed an allocator that best reflected how costs are incurred.

Q. Please describe the allocators used in developing the CCOS.

A. The CCOS was based on three types of allocators:

1. Class determinants – class characteristics, such as number of customers, peak demands, kWh sales, and revenues by rate class;
2. Special studies – detailed analysis of specific plant or expense items, such as meters and uncollectible expenses; and
3. Indirect – composite allocators based on how other costs were allocated.

Schedule TSL-3 contains a description of each allocator used in the CCOS, including what costs are allocated, how each allocator was derived, and the rationale for utilizing the allocator. For example, the 'number of customers' allocator is used to allocate meter reading expenses based on the number of customers in each rate class. The rationale is that meter reading expenses are driven primarily by the number of customer meters that are read monthly. Further details on the allocation factors developed for this study are included in **Schedule TSL-6**.

Q. Please describe the Staff and MECG's proposals in Case No. ER-2019-0374 related to the allocation of production plant in the CCOS study?

A. Staff proposed to allocate production-related costs based on a 100 Highest Hours allocator. MECG proposed to allocate production-related costs utilizing the Average & Excess (A&E) method based on 3 summer and 3 winter month non-coincidental demands (6 NCP).

Q. Did the Company evaluate these methods?

A. Yes. The Company reviewed and evaluated several methods to allocate production cost allocation, as shown in Figure 6 (below). The allocation methods included: 1) Average & Excess (12 NCP) allocation method, consistent with the Company proposed approach in Case No. ER-2019-0374; 2) Average & Excess (6 NCP) allocation method, consistent with the approach recommended by MECG; and 3) 100 Hours method, consistent with the approach recommended by Staff.

The Company's analysis shows that Staff's 100 Hours method results in allocation of production-related costs generally consistent with the A&E 12NCP method, while the A&E 6NCP method results in higher cost allocation to RG rate class and lower cost allocation to GP and LP rate classes.

Figure 6: Production Cost Allocation Factors

Rate Class	A&E 12NCP Allocator	A&E 6NCP Allocator	100 Hours Allocator
RG-Residential	47.42%	49.27%	47.48%
CB-Commercial	8.21%	8.32%	8.94%
SH-Small Heating	1.93%	1.99%	1.87%
GP-General Power	18.00%	17.26%	18.54%
SC-P PRAXAIR Transmission	0.92%	0.84%	0.78%
TEB-Total Electric Bldg	7.06%	7.14%	6.87%
PFM-Feed Mill/Grain Elev	0.02%	0.02%	0.01%
LP-Large Power	15.34%	14.13%	15.48%
MS-Miscellaneous	0.00%	0.00%	0.00%
SPL-Municipal St Lighting	0.58%	0.53%	0.01%
PL-Private Lighting	0.45%	0.43%	0.01%
LS-Special Lighting	0.07%	0.09%	0.00%
Total	100.00%	100.00%	100.00%

The Figure shows that the residential customer class would be allocated 47.42 percent costs using the A&E 12NCP method, 49.27 percent costs using the A&E 6NCP method, and 47.48 percent costs using the 100 hours method.

Q. What is the Company's proposed methodology for the allocation of production plant costs?

A. The Company continues to support using the A&E 12NCP method for the allocation of production-related costs as the method is consistent with the Company's approach to design and build production facilities.

Q. Please describe the development of the A&E allocator.

A. The A&E allocator incorporates both energy consumption and peak demand since it follows the purpose of production plants to provide both energy and meet peak demands.

The A&E allocator consists of two components. The first component of the A&E allocator is average demand, which represents the energy portion of production plant. It represents each rate class's share of the average demand. This component is calculated as each class's share of total kWh sales. The average demand component is weighted by the system load factor representing that portion of the utility's generating capacity that would be needed if all customers used energy at 100.0 percent load factor.

The second component of the A&E allocator is excess demand, which represents the peak demand portion of production plant. It represents each rate class's share of the peak demand – i.e., the demand in excess of the average demand. This component is calculated as each rate class's share of the excess demand – or the difference between the class peak demand and the class average demand. The rate class peak demand is based on NCP demands, consistent with the methodology described in the NARUC Manual.[13] The approach to calculate the A&E allocator in the Company's class cost of service study followed the methodology described in the NARUC Manual, which utilizes NCP demands rather than Coincident Peak ("CP") demands.[14] The NARUC Manual points out that it is a "mistake" to use CP demands instead of NCP demands since it produces an allocator that is equivalent to a CP allocator.[15] Thus, using the CP demands approach is contrary to the

[13] NARUC Electric Utility Cost Allocation Manual, p. 49-52.
[14] Id. at p. 50.
[15] NARUC Electric Utility Cost Allocation Manual states at page 50: "If your objective is -- as it should be using this method -- to reflect the impact of average demand on production plant costs, then it is a mistake to allocate the excess demand with a coincident peak allocation factor because it produces allocation factors that are identical to those derived using a CP method. Rather, use the NCP to allocate the excess demands."

purpose of the A&E allocator since the A&E allocator is designed to allocate costs based on peak and average demands. The excess demand component is weighted by the remaining portion of production plant – i.e., by 1 minus the system load factor – and then added to the average demand component to derive the A&E allocator. As discussed earlier, the Company evaluated two A&E allocators: first, one allocator with NCP demands NCP demands based on an average of the twelve-monthly NCP demands (12NCP); and the second allocator based on an average of three months of winter and three months of summer NCP demands (6NCP).

The A&E allocators were developed utilizing average demand (kWh), and CP and NCP demand data gathered by the Company for each customer class through load research. The CP demand represents class demand at the time of the system peak, while NCP represents aggregate customer peak demand. Further details on the A&E allocator developed for this study are included in **Schedule TSL-7**.

Q. Why did the Company use 12NCP demands in the A&E allocator?

A. The A&E allocator in this study used 12NCP since it is consistent with the design of production plant. The Company's production plant is designed to meet peak demands throughout the year since monthly peak demands are within a relatively narrow range and the monthly reserve margins are similar across the year when considering maintenance schedules, as shown in Figure 7 (below).

Figure 7: Production Plant Generating Capacity and Reserve Margin

	Peak Load	Generating Capacity	Unit Derating	Wtd. Scheduled Maintenance	Assumed Wtd. Forced Outage	Net Generating Capacity	Reserve Margin	Peak Plus Outages
Jan	1,126	1,445	-	-	107	1,337	84.2%	1,233
Feb	1,029	1,445	-	-	111	1,334	77.1%	1,140
Mar	868	1,408	37	60	104	1,207	71.9%	1,069
Apr	672	1,371	74	177	105	1,015	66.2%	1,028
May	776	1,371	74	296	102	899	86.3%	1,248
Jun	996	1,307	138	-	99	1,070	93.1%	1,233
Jul	1,061	1,307	138	-	96	1,072	99.0%	1,296
Aug	1,057	1,307	138	-	96	1,073	98.5%	1,291
Sep	961	1,307	138	107	96	965	99.6%	1,303
Oct	794	1,371	74	243	104	950	83.6%	1,215
Nov	841	1,371	74	150	103	1,043	80.6%	1,169
Dec	942	1,445	-	-	108	1,337	70.4%	1,050
Total	11,123	16,452	886	1,034	1,230	13,303	83.6%	1,189

The Figure shows that the peak demands plus outages are similar across each month of the year; thus, changes in demand in any month can have implications on production capacity decisions.

In addition, the Company's planners stated they consider peak loads throughout the year when making production capacity decisions.

Q. Please describe the results of the A&E method.

A. Figure 8 (below) shows the results of the A&E method.

Figure 8: Results of A&E Method

Average and Excess (12 NCP)						
Rate Class	Peak Demand 12 NCP (MW)	Average Demand (MW)	Excess Demand (MW)	Average Demand (%)	Excess Demand (%)	A&E Allocator (%)
RG-Residential	457,094	205,124	251,970	39.85%	57.60%	47.42%
CB-Commercial	78,646	38,617	40,029	7.50%	9.15%	8.21%
SH-Small Heating	18,367	9,781	8,586	1.90%	1.96%	1.93%
GP-General Power	169,969	102,431	67,538	19.90%	15.44%	18.00%
TS-Transmission Service	8,306	8,179	127	1.59%	0.03%	0.92%
TEB-Total Electric Bldg	66,491	41,736	24,755	8.11%	5.66%	7.06%
PFM-Feed Mill/Grain Elev	186	56	130	0.01%	0.03%	0.02%
LP-Large Power	142,411	105,009	37,402	20.40%	8.55%	15.34%
MS-Miscellaneous	17	17	0	0.00%	0.00%	0.00%
SPL-Municipal St Lighting	5,632	2,190	3,442	0.43%	0.79%	0.58%
PL-Private Lighting	4,390	1,541	2,849	0.30%	0.65%	0.45%
LS-Special Lighting	684	50	634	0.01%	0.15%	0.07%
Total	952,192	514,730	437,462	100.00%	100.00%	100.00%

The Figure shows the results of the A&E method, including the average demand and excess demand components for each rate class, weighted by the system load factor. The Figure shows that the RG rate class allocator is 47.42 percent based on the A&E method, representing a composite of their average demand of 39.85 percent and their peak (in excess of average) demand of 57.60 percent.

The A&E method in this study is generally consistent with the methodology described in the NARUC Manual, and the methodology used in the Company's most recent rate case proceeding.

Q. Please describe the process used to allocate transmission plant.

A. Transmission plant represents 13.7 percent of the Company's utility plant. Transmission costs are incurred consistent with the design of the Company's transmission facilities to meet system capacity requirements. Transmission plant is designed to meet peak demands throughout the year since monthly peak demands are within a relatively narrow range and transmission capacity must be ready throughout the year to move generation output on and off the system when dispatched for the Southwest Power Pool ("SPP"). Thus, transmission plant is allocated based on 12-month average coincident peak ("12CP"). The 12CP allocator is recognized by NARUC as a reasonable transmission cost allocator,[16] and is consistent with the methodologies described in the Company's prior rate case filing (ER-2019-0374).

Q. Please describe the Staff and MECG's proposal in Case No. ER-2019-0374 related to the allocation of demand-related distribution costs?

[16] NARUC Electric Utility Cost Allocation Manual, p. 79.

A. Staff proposed that the allocation of demand-related primary distribution plant facilities be based on sum of each class's coincident peak (12CP) demands at primary voltage levels, and allocation of secondary distribution plant facilities based on the highest coincident peak demands at secondary voltage levels.[17]

MECG recommended allocation of demand-related distribution plant facilities utilizing a single non-coincident peak allocator (1 NCP). [18]

Q. Did the Company evaluate these methods?

A. Yes. The Company reviewed and evaluated several methods to allocate distribution plant, as shown in Figure 9 (below). The allocation methods included: 1) six months non-coincident peak demands (6NCP); (2) 12 months coincident peak demands (12CP); and (3) a single non-coincident peak demand (1NCP).

The Company's analysis shows that the 1NCP allocation factor results in comparatively lower cost allocation to RG rate class and higher cost allocation to C&I rate classes compared to the 6NCP and 12CP methods.

[17] ER-2019-0374 Staff CCOS Report, p. 29
[18] ER-2019-0374 Direct Testimony of Kavita Maini, p. 22-23

Figure 9: Distribution Cost (Primary) Allocation Factors

Rate Class	6NCP Allocator	1NCP Allocator	12CP Allocator
RG-Residential	50.21%	48.29%	49.92%
CB-Commercial	8.44%	8.63%	8.01%
SH-Small Heating	2.01%	2.10%	2.02%
GP-General Power	17.34%	18.12%	17.81%
SC-P PRAXAIR Transmission	0.00%	0.00%	0.00%
TEB-Total Electric Bldg	7.18%	7.52%	7.38%
PFM-Feed Mill/Grain Elev	0.02%	0.02%	0.01%
LP-Large Power	13.72%	14.12%	14.85%
MS-Miscellaneous	0.00%	0.00%	0.00%
SPL-Municipal St Lighting	0.54%	0.52%	0.00%
PL-Private Lighting	0.44%	0.48%	0.00%
LS-Special Lighting	0.09%	0.18%	0.00%
Total	100.00%	100.00%	100.00%

The Figure shows that the residential customer class would be allocated 50.21 percent costs using the 6NCP method, 48.29 percent costs using the 1NCP method, and 49.92 percent costs using the 12CP method.

Q. What is the Company's proposed methodology for the allocation of distribution plant costs?

A. Distribution costs are incurred consistent with the design of the Company's distribution facilities to provide customer access to the electric system (customer-related), and to meet customer peak demands through the year (demand-related).

The Company proposes to allocate the demand portion of distribution costs based on the 1NCP method recommended by MECG in the prior case. The method reflects that the distribution plant is designed to meet customer peak demands. The approach is a refinement to the Company's prior cost of service study. Previously, the demand portion of distribution plant was allocated based on 6-months NCP demands.

The customer portion of distribution plant is allocated to each rate class based on the number of customers.

Q. Please describe the process used to develop special studies allocators.

A. The Company prepared three special studies to allocate meter investments, service investments, and line transformers investments.

- Meter investments were allocated based on the current cost of meters in each rate class. The allocator reflects the Company's estimated cost of meter and meter installation for each rate class.
- Service investments were allocated based on the current cost of services in each rate class. The allocator reflects the Company's estimated cost of service line and installation for each customer class.
- Line transformers were allocated based on number of customers for each customer class. The number of customers were weighted to reflect the average number of customers by rate class served by a single transformer. The allocator recognizes that transformers are built to address varying customer demands and may serve multiple customers within a rate class depending on the demand (e.g., a single transformer serves approximately 2.7 RG customers per Company estimates).

The approach to prepare the special studies is consistent with the methodologies described in the Company's prior rate case filing. The derivation of the meters and services allocators is included in **Schedule TSL-8**.

Q. Please describe the process to develop the composite allocators.

A. There are several composite allocators developed internally based on the allocation of various plant investments and expenses. These are used to allocate cost items that cannot be readily categorized. For example, general plant is allocated based on the composite allocation of all labor-related production, transmission, distribution, customer accounts, and customer service O&M expenses. This approach is well established in industry literature[19] and is consistent with the methodologies described in the Company's prior rate case filing.

Q. Please describe the allocation of O&M expenses to the customer classes.

A. O&M expenses were allocated generally consistent with their respective plant accounts. For example, fixed production O&M expenses were allocated using the A&E Method. Similarly, the allocation of distribution O&M expenses followed the allocation of their respective plant account. Further details on the allocation factors developed for this study are included in **Schedule TSL-3 and TSL-6**.

IV. OVERVIEW OF RATE DESIGN

Q. Please describe the principles used to guide the proposed rate design.

A. The proposed rate design was guided by several principles commonly used throughout the industry, including: (a) rates should recover the overall cost of providing service; (b) rates should be fair, minimizing inter- and intra-class inequities to the extent possible; and (c) rate changes should be tempered by rate continuity concerns.[20]

Because these principles can conflict, the proposed rate design reflects a level of judgment to balance these principles.

[19] NARUC Electric Utility Cost Allocation Manual, p. 105.

[20] See Bonbright, James, Danielsen, Albert, and Kamerschen, David. "Principles of Public Utility Rates." Public Utilities Reports, Inc. pp. 377-407 (2nd Ed. 1988).

Q. How were these principles applied in this proceeding?

A. First, rates were designed to recover the overall cost of service. This was done by developing customer, demand and energy charges based on test year bills, kW billing demands and kWh sales, while incorporating the results of the CCOS. In addition, rates were designed to be fair and equitable. This was done by setting revenue targets for each rate class that reflected in aggregate a movement toward the system ROR. As discussed earlier, the results of the CCOS show that some rate classes produce a ROR that is less than the overall ROR. The proposed rate design reduces that difference by proposing rate increases for certain rate classes that are higher than the system average. Another rate design objective is to moderate rate changes to address rate continuity concerns. This objective was considered while setting revenue targets and then again while setting rate elements.

Q. Please summarize the steps taken to develop the proposed rates.

A. The first step to develop the proposed rates was to establish the overall revenue requirement to be recovered from base rates. The next step was to set revenue targets for each rate class based on the results of the CCOS, as shown on **Schedule TSL-9**. Rates within each rate class were then designed to recover the revenue targets based on test year customer, kW demand and kWh usage data.

Q. What is the total revenue requirement that you used as a starting point?

A. To determine the total revenue requirement, I relied on the overall cost of service presented in the testimony and accounting schedules of Company witness Charlotte T. Emery, which indicates a total revenue requirement of $708.23 million.[21] The total revenue requirement

[21] Excludes the revenue requirements associated with the impact of Winter Storm Uri.

was then reduced by revenues other than base rates to calculate base rate revenue requirements.

Q. Please describe the process to set the revenue targets for each rate class.

A. Since each rate class currently produces a ROR that is different than the overall system ROR, the starting point for setting the revenue targets was to compare current class revenues and class revenues at equalized rates of return.

Q. In general, how did you determine the appropriate rate design within each rate class?

A. The proposed rates were designed by first ensuring the rates recover the proposed revenue target for each rate class. The proposed rates were then designed by reviewing the customer charge to evaluate what level of fixed cost is reasonable to be recovered through the proposed customer charges consistent with rate design objectives described above. Once the proposed customer charges were established, the remaining revenue target for each class was recovered via kWh sales charges, and for certain rate class kW demand charges, as shown in **Schedule TSL-10**.

V. RATE DESIGN AND BILL IMPACT ANALYSES

Q. Please describe the process used to set the revenue requirement targets for each rate class.

A. The starting point for setting the revenue targets was evaluation of the results of the CCOS. Specifically, the process included identifying the base rate changes necessary to achieve equalized rates of return for all rate classes. For those rate classes that produce a ROR less than the system ROR (i.e., the Residential General ("RG"), Miscellaneous Service ("MS"), Municipal Street Lighting ("SPL"), and Special Lighting ("LS") rate classes), the rate increases necessary to achieve equalized rates of return were higher relative to the system average; however, the movement to equalized rates of return for all rate classes was moderated by bill continuity concerns. Below is a brief description of the process for setting revenue targets.

- The revenue targets were set based on a four-step process that balanced the rate design principles discussed earlier, including the equity and bill continuity and gradualism concerns.
  - In the first step, the proposed revenue increase was capped at 95.0 percent of the overall rate increase (or 7.23 percent) for the Residential rate class. This step ensures that the Residential rates address bill continuity and gradualism concerns.
  - In the second step, the proposed revenues were increased by the overall rate increase (or 7.61 percent) for GP, TS, TEB, and PL rate classes whose current rates recover more than their cost of service. This step ensures that the rate increase for these rate classes is not above the overall rate increase.
  - In the third step, the proposed revenues were increased by 95.0 percent of overall rate increase (or 7.23 percent) for the Large Power rate class. This step ensures that the rate increase for the Large Power rate class is somewhat less than the overall rate increase since their current rates recover more than their cost of service. In addition, the Company recognizes that customers in the Large Power rate class tend to be energy-intensive businesses who are highly sensitive to rate changes and thus developed a separate step in setting revenue targets.
  - In the fourth and final step, the remaining revenue deficiency was assigned to all other rate classes in proportion to their current revenues.

Q. Please describe the proposed revenue requirement targets for each rate class.

A. The proposed revenue requirement targets for each class are presented in Figure 10 (below).

Figure 10: Target Revenues

Rate Class		Proposed Revenues		Current Revenues		Increase $	Increase %
RG-Residential	$	314,277,199	$	293,097,843	$	21,179,357	7.2%
CB-Commercial		63,270,070		57,708,886		5,561,184	9.6%
SH-Small Heating		14,251,189		12,998,567		1,252,622	9.6%
GP-General Power		129,577,749		120,418,306		9,159,443	7.6%
TS-Transmission Service		7,973,615		7,409,985		563,630	7.6%
TEB-Total Electric Bldg		54,467,748		50,617,594		3,850,153	7.6%
PFM-Feed Mill/Grain Elev		109,226		99,625		9,601	9.6%
LP-Large Power		114,776,031		107,041,195		7,734,836	7.2%
MS-Miscellaneous		22,039		20,102		1,937	9.6%
SPL-Municipal St Lighting		4,417,117		4,028,871		388,247	9.6%
PL-Private Lighting		4,973,992		4,622,396		351,596	7.6%
LS-Special Lighting		109,357		99,745		9,612	9.6%
Total Company	**$**	**708,225,333**	**$**	**658,163,117**	**$**	**50,062,217**	**7.6%**

Q. Please describe the proposed rate design for the residential rate class.

A. The proposed RG rates were based on a revenue requirement of $314.3 million, which represents an increase of $21.18 million. The proposed rates were based on 1.6 million bills and 1.7 million MWH sales.

The proposed customer charge of $16.00 per month is well below with the underlying cost of service, as shown in **Schedule TSL-10**. The Schedule shows basic customer-related costs of $27.47 per customer per month, and fully-load customer-related costs of $55.15. The Company proposes an increase to the customer charge as a step towards full recovery of the Company's fixed costs in the fixed charge component. The increase in customer charge has two benefits: (1) help mitigate a basic misalignment between the structure of utility rates and the structure of utility costs; and (2) helps minimize intra-class subsidies.

The proposed residential customer charge is generally comparable to residential customer charges at other electric utilities in Missouri, as shown in Figure 11, recognizing however, that many of the other electric utilities are cooperatives. The Figure shows the average monthly residential customer charge in Missouri is $25.71 per customer.

Figure 11: Missouri Electric Utility Customer Charges[22]

Empire District Electric (MISSOURI) Customer Charge Survey	Residential
Union Electric Co - (MO)	9.00
KCP&L Greater Missouri Operations Co.	11.47
Kansas City Power & Light Co	11.47
Webster Electric Coop	24.00
Southwest Electric Coop, Inc	25.00
Black River Electric Coop - (MO)	25.00
Platte-Clay Electric Coop, Inc	25.38
Ozark Border Electric Coop	26.00
Farmers Electric Coop, Inc - (MO)	26.00
Laclede Electric Coop, Inc	27.00
Ozark Electric Coop Inc - (MO)	27.50
Citizens Electric Corporation - (MO)	29.00
Boone Electric Coop	29.95
Carroll Electric Coop Corp	30.00
White River Valley El Coop Inc	31.00
Osage Valley Elec Coop Assn	31.00
Co-Mo Electric Coop Inc	35.00
Callaway Electric Cooperative	39.00
Average	$ 25.71

The revenue requirement not recovered through the customer charge is recovered from winter volumetric charges of $0.13564 per kWh for first 600 kWh of usage and $0.10922 per kWh for all additional usage and summer volumetric charges of $0.13564

[22] We note that Union Electric Company has recently proposed an increase in Customer Charge to $11.00 per month for Residential customers (except for Residential Smart Saver Service and Residential Ultimate Saver Service) (Direct Schedule of Michael W. Harding (MWH-D1) filed March 31, 2021 in Case ER-2021-0240)

per kWh for all kWh usage. The proposed rate design and bill impact analyses are included in **Schedule TSL-10**.

Overall, the proposed base rates will increase a monthly bill, including EECR and Storm Uri charge, of an RG customer using 1,000 kWh per month by $12.76 per month. [23]

Q. Please describe the proposed rate design for the C&I rate classes.

A. The proposed rates for C&I and Lighting rate classes are developed based on the revenue targets presented in Figure 10 (above). The Company proposes an increase to the customer charges for C&I rate classes for the same reasons discussed above for Residential class. The proposed revenue targets, billing determinants, rate design and bill impact analyses are included in **Schedule TSL-10**.

Q. Have you examined the impact of your proposed changes in base rates on customers for each rate class?

A. Yes. As shown in **Schedule TSL-10**, the Company evaluated the customer bill impacts of the proposed base rate changes based on a range of annual usage within each rate class. The bill impact analysis was prepared in two ways:

1. Proposed Base Rates vs. Current Base Rates, comparing (i) the proposed base rates, and (ii) the current base rates; and
2. Proposed Total Bill vs. Current Total Bill, comparing (i) the proposed base rates plus the EECR charge and Storm Uri Charge, and (ii) the current base rates plus the EECR charge and Storm Uri Charge.

[23] Based on a monthly bill for a Residential General customer using 1,000 kWh per month, including EECR of $0.00045 per kWh and Storm Uri charge of $0.00708 per kWh.

Q. What is the monthly bill impact for residential and commercial customers?

A. Figure 12 (below) shows the annual bill impact for the residential and commercial customer classes.

Figure 5: Bill Impact Analysis

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Impact without Storm Uri (1)

		Average Annual Customer Impact		Aggregate Annual Impact	
Class	Average Customer Count	Bill Change $	Bill Change %	Annual Change $	Annual Change %
RG-Residential	133,243	$ 160	9.3%	$ 21,358,544	9.3%
CB-Commercial	18,355	305	12.3%	5,592,189	12.3%
SH-Small Heating	3,196	394	12.7%	1,259,903	12.7%
GP-General Power	1,804	5,108	10.4%	9,215,300	10.4%
TS-Transmission Service	1	201,407	4.1%	201,407	4.1%
TEB-Total Electric Bldg	932	4,160	10.3%	3,876,842	10.3%
PFM-Feed Mill/Grain Elev	10	975	11.8%	9,672	11.8%
LP-Large Power	43	181,474	10.5%	7,792,817	10.5%
MS-Miscellaneous	2	897	12.9%	1,944	12.9%
SPL-Municipal St Lighting	6	66,932	16.9%	390,437	16.9%
PL-Private Lighting	245	1,444	8.7%	353,294	8.7%
LS-Special Lighting	122	81	11.8%	9,867	11.8%
Total	157,958			$ 50,062,217	

(1) The current annual bill reflects the current base rates; a Storm Uri Charge of $0.00708; and EECR of $0.00045
The proposed annual bill reflects the proposed base rates; a Storm Uri Charge of $0.00708; and EECR of $0.00045

VI. RATE CONSOLIDATION

Q. Did the Company evaluate Staff's recommendation in ER-2019-0374 to consolidate Schedules CB and SH?

A. Yes. The Company's primary concern related to Staff's recommendation to consolidated Schedules CB and SH was the potential adverse bill impacts on CB and SH customers. To evaluate Staff's proposal, the Company conducted a billing analysis for all CB and SH customer bills during the test year. The billing analysis was conducted in three steps:

First, the Company developed a consolidated rate on a revenue neutral basis for CB and SH rate schedules based on the Company's current revenues for the two schedules.

The Company maintained the customer charge and tail block winter rates for the CB and SH schedules. The remaining revenue requirement was set to be recovered through the volumetric charges consistent with the current CB and SH rates.

Second, the Company re-calculated all CB and SH customer bills through the test year using the Company's proposed separate rates and the consolidated rates (developed in step 1). The CB customer bills were calculated using two sets of rates: 1) the Company's proposed CB rates; and 2) the CB/SH consolidated rates. The SH customer bills were also calculated using two sets of rates: 1) the Company's proposed SH rates; and 2) the CB/SH consolidated rates.

Third, the Company categorized customers based on their usage levels and evaluated bill impacts for each customer category. The analysis shows the impact on customer bills if the customers switch from a separate CB or SH rate schedule to the consolidated CB/SH rate schedule. The Company's bill impact analysis for CB customers is shown in Figure 13 (below).

Figure 13: Bill Impact Analysis for CB Rate Schedule

Commercial (CB)	% Customers	Annual Bill ($) Current CB Rate	Annual Bill ($) Cons. CB-SH Rate	Avg. Increase / (Decrease) ($)	Avg. Increase / (Decrease) (%)
Annual Usage					
1-400 KWH	8%	$ 292	$ 292	$ (0.1)	0.0%
400-1,400 KWH	10%	379	379	(0.4)	-0.1%
1,400-3,100 KWH	10%	548	547	(1.0)	-0.2%
3,100-5,200 KWH	11%	811	809	(1.9)	-0.2%
5,200-7,400 KWH	10%	1,077	1,074	(2.7)	-0.3%
7,400-11,100 KWH	10%	1,425	1,421	(3.6)	-0.3%
11,100-16,700 KWH	10%	1,954	1,949	(4.7)	-0.2%
16,700-26,300 KWH	10%	2,865	2,858	(6.1)	-0.2%
26,300-47,400 KWH	10%	4,504	4,496	(8.5)	-0.2%
47,400+ KWH	10%	10,305	10,287	(17.6)	-0.2%
Total Class (Average)	**100%**	**$ 2,414**	**$ 2,410**	**$ (4.6)**	**-0.2%**

The Figure shows that on a consolidated CB/SH rate schedule, the CB customers would experience lower annual bills compared to a separate CB rate schedule.

The Company's bill impact analysis for SH customers is shown in Figure 14 (below).

Figure 6: Bill Impact Analysis for CB Rate Schedule

Space Heating (SH)	% Customers	Annual Bill ($) Current SH Rate	Annual Bill ($) Cons. CB-SH Rate	Avg. Increase / (Decrease) ($)	Avg. Increase / (Decrease) (%)
Annual Usage					
1-1,700 KWH	9%	$ 354	$ 356	$ 1.5	0.4%
1,700-5,100 KWH	10%	693	700	7.5	1.1%
5,100-8,500 KWH	10%	1,102	1,116	13.9	1.3%
8,500-11,900 KWH	10%	1,455	1,473	18.1	1.2%
11,900-16,500 KWH	10%	1,879	1,901	22.3	1.2%
16,500-21,700 KWH	10%	2,389	2,415	26.5	1.1%
21,700-29,300 KWH	10%	3,020	3,052	31.3	1.0%
29,300-42,400 KWH	10%	4,070	4,110	40.2	1.0%
42,400-69,100 KWH	10%	6,007	6,061	54.8	0.9%
69,100+ KWH	10%	10,214	10,303	89.2	0.9%
Total Class (Average)	**100%**	**$ 3,123**	**$ 3,154**	**$ 30.6**	**1.0%**

The Figure shows that on a consolidated CB/SH rate schedule, the SH customers would experience slightly higher annual bills compared to a separate SH rate schedule.

Q. Did the Company evaluate Staff's recommendation in ER-2019-0374 to consolidate Schedules GP and TEB?

A. Yes. The Company conducted a bill impact analysis for GP and TEB customers, similar to the analysis discussed above for CB and SH customers. Specifically, the Company created a consolidated GP/TEB rate schedule and re-calculated all GP and TEB customer bills through the test year to evaluate the bill impacts if the customers switch to the consolidated GP/TEB rate schedule.

The Company's bill impact analysis for GP customers is shown in Figure 15 (below).

Figure 15: Bill Impact Analysis for GP Rate Schedule

General Power (GP)	% Customers	Annual Bill ($) Current GP Rate	Annual Bill ($) Cons. GP-TEB Rate	Avg. Increase / (Decrease) ($)	Avg. Increase / (Decrease) (%)
Annual Usage					
1-80 MWH	10%	$ 9,457	$ 9,150	$ (307)	-3.2%
80-120 MWH	11%	13,155	12,913	(242)	-1.8%
120-140 MWH	7%	14,899	14,707	(192)	-1.3%
140-190 MWH	13%	19,187	18,890	(297)	-1.5%
190-230 MWH	8%	23,048	22,770	(277)	-1.2%
230-310 MWH	12%	28,604	28,291	(313)	-1.1%
310-390 MWH	8%	36,079	35,735	(344)	-1.0%
390-600 MWH	10%	46,967	46,596	(371)	-0.8%
600-1,170 MWH	10%	76,007	75,489	(518)	-0.7%
1,170+ MWH	10%	240,130	239,085	(1,045)	-0.4%
Total Class (Average)	**100%**	**$ 50,844**	**$ 50,451**	**$ (393)**	**-0.8%**

The Figure shows that on a consolidated GP/TEB rate schedule, the lower usage GP customers would experience approximately 3.0 percent lower rates, while the higher usage GP customers would experience approximately 0.5 percent lower rates.

The Company's bill impact analysis for TEB customers is shown in Figure 16 (below).

Figure 16: Bill Impact Analysis for TEB Rate Schedule

Total Electric Bldg (TEB)	% Customers	Annual Bill ($) Current TEB Rate	Annual Bill ($) Cons. GP-TEB Rate	Avg. Increase / (Decrease) ($)	Avg. Increase / (Decrease) (%)
Annual Usage					
1-80 MWH	8%	$ 7,537	$ 7,953	$ 416	5.5%
80-110 MWH	13%	12,121	12,660	538	4.4%
110-140 MWH	7%	14,711	15,282	571	3.9%
140-170 MWH	11%	17,368	17,914	546	3.1%
170-200 MWH	11%	20,076	20,513	437	2.2%
200-250 MWH	11%	24,010	24,490	479	2.0%
250-320 MWH	9%	30,011	30,774	763	2.5%
320-420 MWH	11%	36,617	37,100	483	1.3%
420-600 MWH	10%	51,666	52,460	794	1.5%
600+ MWH	10%	105,030	106,590	1,560	1.5%
Total Class (Average)	**100%**	**$ 31,934**	**$ 32,590**	**$ 656**	**2.1%**

The Figure shows that on a consolidated GP/TEB rate schedule, the lower usage TEB customers would experience approximately 5.0 percent higher rates, while the higher usage TEB customers would experience approximately 1.5 percent higher rates.

Q. Did the Company evaluate consolidation of PFM Schedule with Schedules GP and TEB?

A. While Staff proposed consolidation of Schedule PFM with Schedules GP and TEB, the Company did not conduct this analysis as the rate structure of PFM schedules is substantially different than the rate structure of GP and TEB rate classes.

For example, the GP and TEB rate classes are billed energy charges based on hours of usage, i.e., for first 150 hours of usage, next 200 hours of usage, and all additional hours of usage. By comparison, the PFM rate class is billed energy charges based on kWh usage, i.e., for first 700 kWh usage, and for all additional usage. In addition, the GP and TEB classes are billed for demand while PFM class is only billed for energy usage. Thus, the billing determinants required to compare PFM with the GP and TEB rate classes were not available due to the different rate structures. Even if such billing determinants were available, the cost of serving the PFM rate class is more consistent with the CB and SH rate classes than the GP and TEB rate classes, as shown in Figure 5 (above).

Q. Did the Company evaluate consolidation of PFM Schedule with Schedules CB and SH?

A. Yes. The Company conducted a bill impact analysis for CB, SH, and PFM customers, similar to the analyses discussed above. Specifically, the Company created a consolidated CB/SH/PFM rate schedule and re-calculated all CB, SH, and PFM customer bills through the test year to evaluate the bill impacts if the customers switch to the consolidated rate schedule. Since the PFM is a small class, the bill impacts on CB and SH customers was similar to bill impacts presented in Figures 13 and 14 (above).

The bill impact analysis for PFM customers is shown in Figure 17 (below).

Figure 17: Bill Impact Analysis for PFM Rate Schedule

Feed Mill/Grain Elev (PFM)	% Customers	Annual Bill ($) Current PFM Rate	Annual Bill ($) CB-SH-PFM Rate	Avg. Increase / (Decrease) ($)	Avg. Increase / (Decrease) (%)
Annual Usage					
1-2,700 KWH	10%	$ 807	$ 616	$ (190.4)	-23.6%
2,700-3,900 KWH	10%	816	620	(195.7)	-24.0%
3,900-7,700 KWH	10%	1,047	783	(263.8)	-25.2%
7,700-12,200 KWH	10%	1,919	1,413	(505.6)	-26.4%
12,200-14,500 KWH	10%	2,749	2,003	(746.5)	-27.2%
14,500-22,300 KWH	10%	2,828	2,062	(766.0)	-27.1%
22,300-44,300 KWH	10%	5,918	4,269	(1,649.3)	-27.9%
44,300-73,300 KWH	10%	11,873	8,533	(3,340.3)	-28.1%
73,300-100,200 KWH	10%	15,214	10,917	(4,297.1)	-28.2%
100,200+ KWH	10%	31,559	22,586	(8,973.4)	-28.4%
Total Class (Average)	**100%**	**$ 7,473**	**$ 5,380**	**$ (2,092.8)**	**-28.0%**

The Figure shows that on a consolidated CB/SH/PFM rate schedule, the PFM customers would experience approximately 28.0 percent lower rates.

VII. <u>CASH WORKING CAPITAL AND LEAD-LAG STUDY</u>

Q. Please define the term "Cash Working Capital."

A. The term "cash working capital" refers to the net funds required by the Company to finance goods and services used to provide service to customers from the time those goods and services are paid for by the Company to the time that payment is received from customers. Goods and services considered in this lead-lag study include O&M expenses, including labor and non-labor expenses; federal, state, and local taxes; and employment taxes.

Q. Please describe the approach used to develop the lead-lag study.

A. The lead-lag study consists of two components: a revenue lag and expense leads.

The revenue lag represents the number of days from the time customers receive service to the time customers pay for their service, *i.e.,* when the funds are available to the Company. The longer the revenue lag, the more cash the Company needs to finance its day-to-day operations.

The expense lead represents the number of days from the time the Company receives goods and services used to provide service to the time payments are made for those goods and services, *i.e.,* when the funds are no longer available to the Company. The longer the expense lead, the less cash the Company needs to fund its day-to-day operations. Together, the revenue lag and expense leads are used to measure the lead-lag days.

The results of the lead-lag study were used to determine the Company's CWC requirement by applying the lead-lag days to the Company's adjusted test year expenses. The CWC requirement is included in the Company's rate base.

Q. Please summarize the results of the lead-lag study.

A. The results of the lead-lag study are summarized in **<u>Schedule TSL-11</u>** and show a CWC requirement of $(7.9) million.[24]

Q. Do the results of the lead-lag study represent an accurate assessment of the Company's CWC requirement?

A. Yes, the lead-lag study represents an accurate assessment of the Company's CWC requirement during the test year for the Company's Missouri jurisdiction.

The lead-lag study relies in large part on the Commission's decision in the Company's most recent rate case proceeding in Case No. ER-2019-0374.[25] Specifically, the Company used the expense lead days that were approved by the Commission in that proceeding, as explained below.

However, the Company updated the revenue lag to reflect more recent collections experience, as explained below.

Q. Please summarize the approach used to develop the lead-lag study.

A. The lead-lag study compares differences between the Company's revenue lag and expense leads. The revenue lag measures the number of days from the time service is provided to customers to the time payment is received from customers. The expense lead represents the number of days from the time the Company receives goods and services used to provide service to the time payments are made for those goods and services. The lag and leads are measured in days for individual expenses and then converted to "dollar-days" that reflect a weighting by expense amounts.

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[24] Excludes the cash working capital requirements associated with the impact of Winter Storm Uri.
[25] Report and Order, issued July 1, 2020 in File No. ER-2019-0374

A. Revenue Lag

Q. How was the revenue lag determined?

A. The revenue lag was based on the number of days from the time service is provided to customers to the time payment is received from customers. The revenue lag is the sum of three components: (1) the service lag; (2) the billing lag; and (3) the collection lag.

Q. What is the service lag?

A. The service lag measures the average number of days in the service period; that is, the number of days between the start and end of the billing month. Meters are read at the end of the billing month.

The service lag in this lead-lag study was based on the midpoint of the service period.

Q. What is the billing lag?

A. The billing lag measures the number of days from the time meters are read at the end of the billing period to the time bills are prepared, recorded, and sent to customers. The billing lag includes time for review and validation of billed usage and dollars.

Q. What is the collection lag?

A. The collection lag measures the number of days from the time bills are recorded and sent to customers to the time customer payments are received (i.e., funds are available to the Company). The collection lag in this lead-lag study was based on the Company's customer billing data.

Q. Why did the Company update the revenue lag in this proceeding?

A. The Company updated the revenue lag in this proceeding due to changes in its collection lag since the most recent rate case. Specifically, the collection lag for the twelve-month period ending September 30, 2020 test year was 24.85 days. By comparison, the collection lag approved by the Commission in its most recent rate case was 21.71 days.

B. Expense Lead

Q. How were expense lead days determined in this lead-lag study?

A. Expense lead days in this lead-lag study are identical to those approved by the Commission in the Company's most recent rate case proceeding in Case No. ER-2019-0374, as included in **Schedule TSL-11**, page 1 of 2.[26]

Q. Why did the Company use the expense lead days approved by the Commission in Case No. ER-2019-0374?

A. The Company used the expense lead days approved by the Commission in Case No. ER-2019-0374 for three reasons: (1) the Commission's decision in Case No. ER-2019-0374 was based on a comprehensive review, evaluation and proposed modifications of the Company's lead-lag study by the parties in that proceeding; (2) the Commission's decision in Case No. ER-2019-0374 was contemporaneous with the test year used to prepare the Company's lead-lag study in this proceeding; and (3) there have been no substantial changes in the Company's payment processes or practices during the test year that would result in a significant change in lead days.

By comparison, there has been a substantial change in the Company's collection lag, as discussed earlier, which is why the Company proposes to update the revenue lag in this proceeding.

[26] *Report and Order*, issued July 1, 2020, File No. ER-2019-0374.

VIII. CONCLUSION

Q. Please briefly summarize your Direct Testimony.

A. This testimony describes the approach used to design the proposed electric rates for the Missouri jurisdiction of the Company. The proposed base rates reflect three important utility rate design principles: (a) rates should recover the overall cost of providing service; (b) rates should be fair, minimizing inter- and intra-class inequities to the extent possible; and (c) rate changes should be tempered by rate continuity concerns.

The Company's proposed rate design is based on the results of the Company's CCOS which shows that the current rate design produces a disparity in class rates of return. The results of the CCOS support a movement toward a more equitable rate structure where class RORs move closer to the system ROR. Except as described in this testimony, the CCOS was prepared consistent with the methodologies described in the Company's 2019 rate case filing.

The Company prepared a bill impact analysis to evaluate the impact of the proposed base rate changes. Overall, the proposed base rates will increase the total monthly bill of a Residential General (RG) customer using 1,000 kWh per month by $12.76 per month. [27]

Q. Does this conclude your Direct Testimony at this time?

A. Yes, it does.

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[27] Based on a monthly bill for a Residential General customer using 1,000 kWh per month, including EECR of $0.00045 per kWh and Storm Uri charge of $0.00708 per kWh.

VERIFICATION

I, Timothy S. Lyons, under penalty of perjury, on this 28th day of May, 2021, declare that the foregoing is true and correct to the best of my knowledge and belief.

/s/ Timothy S. Lyons