Exhibit No.:
Issues: Cost of Service Study, Rate Design, Lead-Lag Study, Weather Normalization Rider, Bill Impact Analyses, Inclining Block Rates, MO Jurisdiction Cash Working Capital Requirement
Witness: Timothy S. Lyons
Type of Exhibit: Direct Testimony
Sponsoring Party: The Empire District Electric Company
Case No.: ER-2019-0374
Date Testimony Prepared: August 2019

Before the Public Service Commission of the State of Missouri

Direct Testimony

of

Timothy S. Lyons

On behalf of

The Empire District Electric Company
A Liberty Utilities Company

August 2019

Liberty Utilities
EMPIRE DISTRICT

TABLE OF CONTENTS
DIRECT TESTIMONY OF
TIMOTHY S. LYONS
ON BEHALF OF
THE EMPIRE DISTRICT ELECTRIC COMPANY
BEFORE THE
MISSOURI PUBLIC SERVICE COMMISSION
CASE NO. ER-2019-0374

SUBJECT **PAGE**

I. INTRODUCTION 1

II. PURPOSE OF TESTIMONY 2

III. SUMMARY OF FINDINGS AND RECOMMENDATIONS 2

IV. OVERVIEW 4

V. ALLOCATED COST OF SERVICE STUDY 8

VI. OVERVIEW OF RATE DESIGN 28

VII. RATE DESIGN AND BILL IMPACT ANALYSES 30

VIII. INCLINING BLOCK RATES 38

IX. MISSOURI JURISIDICTION CASH WORKING CAPITAL ("CWC") REQUIREMENT 43

X. LEAD-LAG STUDY APPROACH 45

XI. WEATHER NORMALIZATION RIDER 51

XII. CONCLUSION 59

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LIST OF EXHIBITS

SCHEDULE TSL-1	Testimony Experience
SCHEDULE TSL-2	Cost of Service Results
SCHEDULE TSL-3	Description of Functional Factors, Classifiers and Allocators
SCHEDULE TSL-4	Summary of Functional Factors
SCHEDULE TSL-5	Summary of Classification Factors
SCHEDULE TSL-6	Summary of Allocation Factors
SCHEDULE TSL-7	Average and Excess Allocator
SCHEDULE TSL-8	Meter and Services Allocators
SCHEDULE TSL-9	Revenue Targets
SCHEDULE TSL-10	Rate Design and Bill Impact Analysis
SCHEDULE TSL-11	Lead Lag Summary
SCHEDULE TSL-12	Lead Lag Supporting Schedules

DIRECT TESTIMONY
OF
TIMOTHY S. LYONS
ON BEHALF OF
THE EMPIRE DISTRICT ELECTRIC COMPANY
BEFORE THE
MISSOURI PUBLIC SERVICE COMMISSION

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. PLEASE DESCRIBE YOUR CURRENT POSITION.

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

Q. PLEASE DESCRIBE YOUR PROFESSIONAL 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 on June 1, 2016.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND.

A. 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. A summary of my testimony experience is included in Schedule TSL-1.

II. PURPOSE OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

A. This testimony describes the approach used to design the proposed electric rates for the Missouri jurisdiction of The Empire District Electric Company, a Liberty Utilities company ("Liberty-Empire" or the "Company"). The 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; (d) a discussion of the Company's analysis regarding energy use as related to residential block rates; (e) development of the lead-lag study used to support the Company's Cash Working Capital ("CWC") analysis; and (f) development of the proposed Weather Normalization Rider.

Q. HAVE YOU PREPARED SCHEDULES TO SUPPORT THIS TESTIMONY?

A. Yes. Schedules TSL-2 through TSL-12 summarize the results of the CCOS, rate design and lead-lag study. The Schedules were prepared by me or under my direction.

III. SUMMARY OF FINDINGS AND RECOMMENDATIONS

Q. PLEASE SUMMARIZE YOUR 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, Miscellaneous Service, Municipal Street Lighting, and Special Lighting 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 described in the Company's 2014 rate case filing.[1]

The results of the CCOS support a movement toward a more equitable rate structure where class RORs move closer to the system ROR. To meet that objective, the proposed rate increases for the Residential and Miscellaneous Service, Municipal Street Lighting and Special Lighting rate classes are higher than the overall rate increase. However, the proposed movement to the system ROR was subject to certain limitations to address customer bill impact considerations. The proposed rates for the remaining C&I and Lighting rate classes also move the class RORs closer to the system ROR.

The proposed rate design reflects improved alignment between monthly customer charges and customer-related costs for certain rate classes. The proposed General Power and Large Power rate design, as explained below, reflects no change to the commodity rates and billing demand charges and increases to the customer and facilities demand charges.

The Company prepared a bill impact analysis to evaluate the impact of the proposed 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

[1] File No. ER-2014-0351, *In the Matter of The Empire District Electric Company for Authority to File Tariffs Increasing Rates for Electric Service Provided to Customers in the Company's Missouri Service Area.*

2. Proposed Total Bill vs. Current Total Bill, comparing (i) the proposed base rates plus the Energy Efficiency Cost Recovery ("EECR") charge, and (ii) the current base rates plus Fuel Adjustment Clause ("FAC") charge, EECR charge, and Tax Reform Credit. This provides a more accurate assessment of the bill impact resulting from the Company's proposal.

Overall, the proposed base rates will increase the total monthly bill of an average use Residential General ("RG") customer by $8.02 per month, or 5.8 percent.[2]

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.

IV. OVERVIEW

Q. PLEASE DESCRIBE LIBERTY-EMPIRE'S SERVICE AREA.

A. Liberty-Empire, a subsidiary of Algonquin Power & Utilities Corp., 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 155,165 electric customers in Missouri, including 130,887 (84.4 percent) residential customers, 23,893 (15.4 percent) C&I customers, and 385 (0.2 percent) lighting customers.

[2] Based on an average monthly bill for a Residential General customer using 12,772 kWh per year, including EECR charge of $0.00039 per kWh.

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 are shown in Figure 1.

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	Miscellaneous Service MS
Current Rates									
Customer Charge	$ 13.00	$ 22.69	$ 22.69	$ 69.49	$ 259.01	$ 69.49	$ 27.65	$ 283.55	$ 19.51
kWh Charge - Winter									
1st Block kWh Charge	0.13006	0.13168	0.12872	0.07799	0.03838	0.08272	0.18020	0.06048	0.10170
2nd Block kWh Charge	0.10574	0.11838	0.09616	0.06420	-	0.06705	0.16370	0.03552	
3rd Block kWh Charge				0.06368	0.03184	0.06580			
kWh Charge - Summer									
1st Block kWh Charge	0.13006	0.13168	0.12872	0.09024	0.05412	0.10817	0.18020	0.06809	0.10170
2nd Block kWh Charge	0.13006	0.13168	0.12872	0.07084	0.04371	0.08472	0.18020	0.03683	
3rd Block kWh Charge				0.06398	0.03373	0.07665			
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, EECR charge, and a tax reform credit.[3] 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 rate decreases as monthly consumption increases. For example, the energy charges for the Residential General ("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 $0.13006 per kWh while

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

consumption greater than 600 kWh (i.e., second rate block) is charged $0.10574 per kWh. The current base rates took effect in September 2016.

Q. PLEASE DESCRIBE THE LOAD PROFILE OF THE COMPANY'S RATE CLASSES.

A. Figure 2 provides a breakdown of test year customers and kWh sales by rate class. The test year represents the period April 1, 2018 through March 31, 2019. The usage in Figure 2 has been normalized for weather.

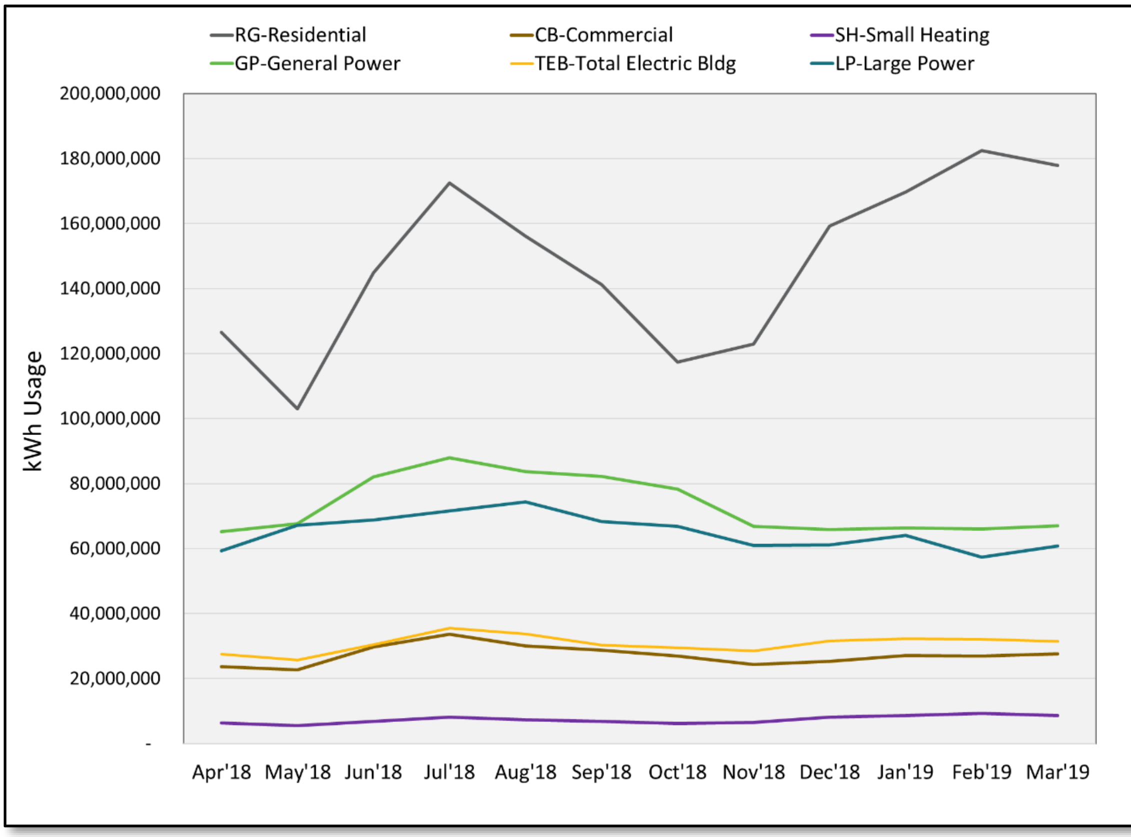
Figure 2: Test Year Customers and Sales

Rate Class	Number of Customers	% of Customers	Sales kWh	% of Sales	kWh Usage per Customer
RG-Residential	130,887	84.4%	1,671,631,047	39.7%	12,772
CB-Commercial	18,072	11.6%	316,607,625	7.5%	17,519
SH-Small Heating	3,028	2.0%	84,989,044	2.0%	28,068
GP-General Power	1,793	1.2%	868,722,208	20.6%	484,508
SC-P PRAXAIR Transmissi	1	0.0%	69,738,355	1.7%	69,738,355
TEB-Total Electric Bldg	946	0.6%	358,252,991	8.5%	378,636
PFM-Feed Mill/Grain Ele	10	0.0%	420,183	0.0%	42,018
LP-Large Power	40	0.0%	805,901,650	19.1%	20,189,603
MS-Miscellaneous	3	0.0%	138,894	0.0%	46,298
SPL-Municipal St Lighting	7	0.0%	22,413,186	0.5%	3,201,884
PL-Private Lighting	252	0.2%	12,922,453	0.3%	51,365
LS-Special Lighting	126	0.1%	768,343	0.0%	6,106
Total	155,165	100.0%	4,212,505,979	100.0%	27,149
Residential	130,887	84.4%	1,671,631,047	39.7%	12,772
C&I	23,893	15.4%	2,504,770,950	59.5%	104,832
Lighting	384	0.2%	36,103,982	0.9%	93,919

The Figure shows the RG class represents a majority (84.4 percent) 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 12,772 kWh per year, while Large Power customers use on average 20,189,603 kWh per year.

Figure 3 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.

V. 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[4] and is consistent with the methodologies described in the Company's prior rate case.[5]

Q. PLEASE DESCRIBE THE APPROACH USED TO DEVELOP THE CCOS FOR THIS CASE.

A. The cost of service 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

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

[5] File No. ER-2014-0351, *In the Matter of The Empire District Electric Company for Authority to File Tariffs Increasing Rates for Electric Service Provided to Customers in the Company's Missouri Service Area.*

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.

Q. HOW WERE COSTS FUNCTIONALIZED FOR THE CCOS?

A. The functionalization of costs in this study is 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.

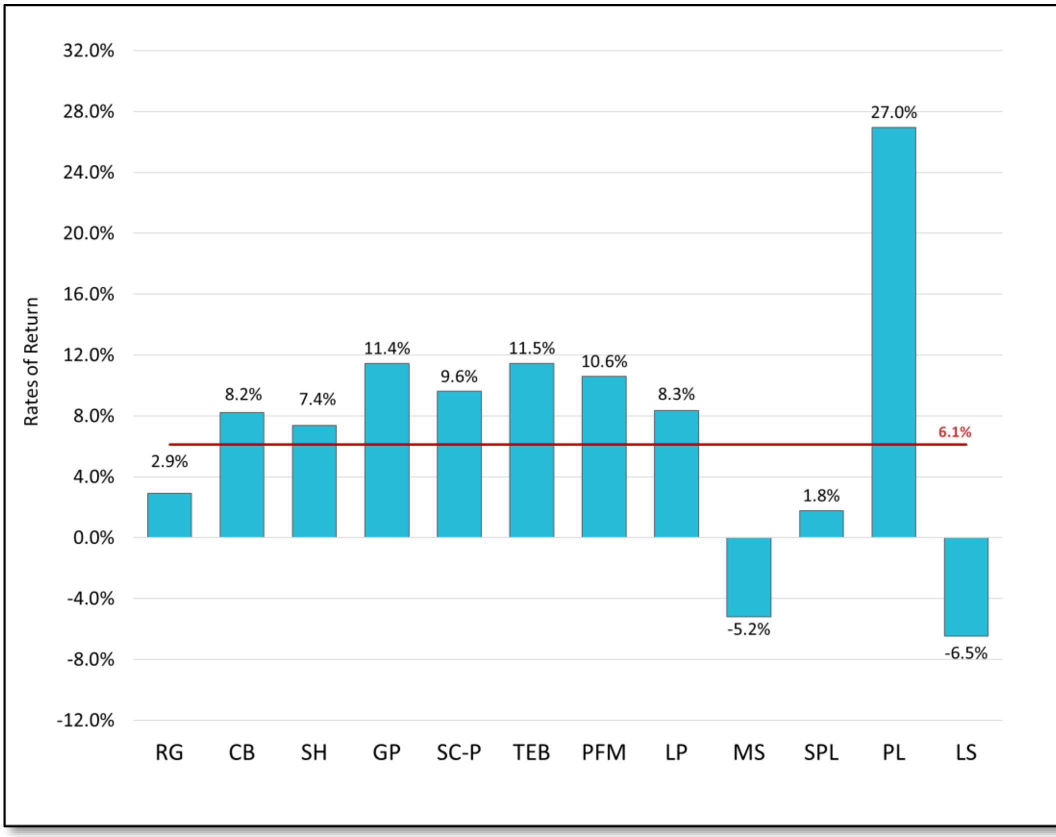
Q. HOW WAS THE CCOS DEVELOPED?

A. The CCOS was based on a spreadsheet model developed by ScottMadden for this filing. Each rate base and expense item in the CCOS 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. 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

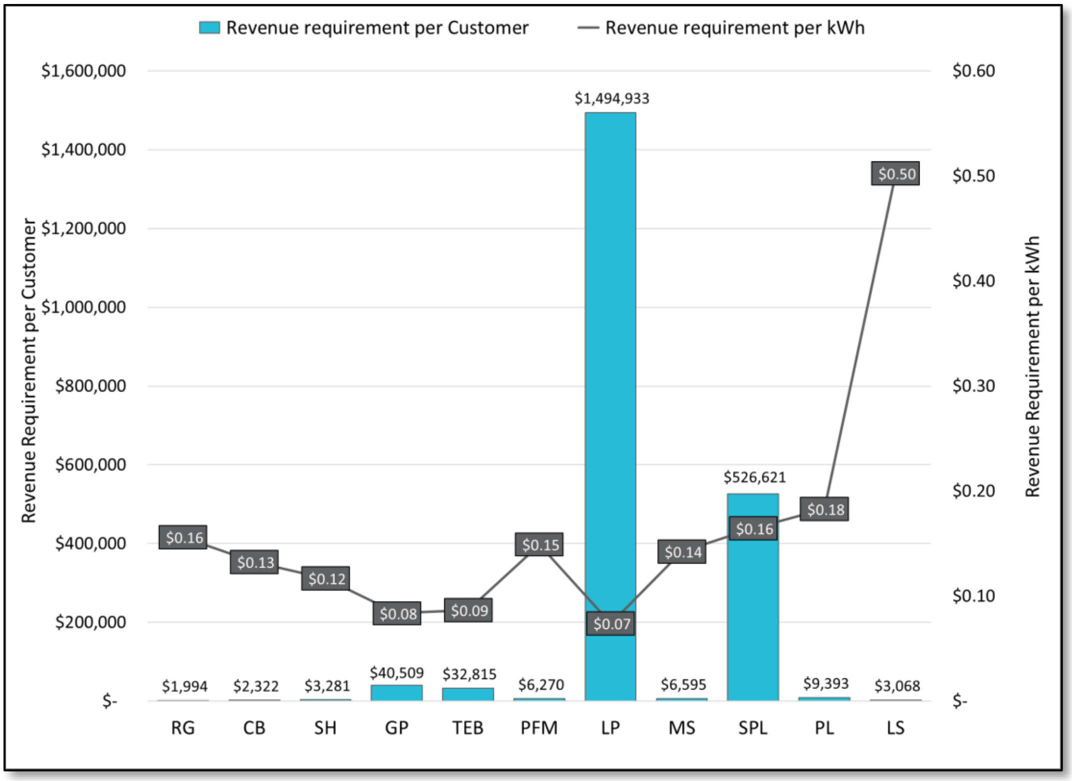


The Figure shows the Company's RG, Miscellaneous Service, Municipal Service, Street Lighting and Special Lighting rate classes produce a ROR below the system ROR. The C&I and remaining Lighting rate classes produce a ROR above the system ROR. Further details are included in Schedule TSL-2.

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., unit cost of service) varies across the Company's rate classes, as shown in Figure 5.

Figure 5: Unit Cost of Service by Rate Class[6]



The Figure shows, for example, the unit cost of service for the RG rate class is $1,994 per customer, while the unit cost of service for the Large Power rate class is $1,494,933 per customer. In comparison, the unit cost of service for the RG class is $0.16 per kWh, while the unit cost of service for the Large Power rate class is $0.07 per kWh.

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.

[6] For confidentiality purpose, SC-P rate class average cost of service is not shown in the testimony.

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 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 is based on test year data for the period April 1, 2018 through March 31, 2019. 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. 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. 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-3.

Q. PLEASE DESCRIBE THE CLASSIFICATION PROCESS USED IN DEVELOPING THE COST OF SERVICE STUDY.

A. The cost of service is 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 segmented based on their underlying characteristics. Some costs were classified as customer-related, while others were classified as demand-related. The minimum-size method was used to perform the segmentation.

Q. PLEASE EXPLAIN THE CLASSIFICATION OF DISTRIBUTION FACILITIES.

A. Distribution plant represents 36.2 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 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. [7]

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

[7] NARUC Electric Utility Cost Allocation Manual, Pg. 90.

prior rate case filing.[8] As discussed earlier, distribution plant and related costs are separated into two functions: primary and secondary distribution. The primary distribution facilities and line transformers are classified as either customer- or demand-related using the minimum-size method. Secondary distribution is 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 based on 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. While there are several methods to classify costs between customer and demand, the Minimum-size Method was used in this study since it represents the actual 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

[8] File No. ER-2014-0351, *In the Matter of The Empire District Electric Company for Authority to File Tariffs Increasing Rates for Electric Service Provided to Customers in the Company's Missouri Service Area.*

allocated to each rate class based on the number of customers. Distribution plant in excess of the minimum system reflect the cost of serving customer peak demands. The "peak demand" costs are allocated to each rate class based on customer peak demands. The approach is consistent with the methodology 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.[9]

The approach used in this study was based on the current cost of the minimum-sized installation of each plant account relative to historical cost indexed to current costs utilizing the Handy-Whitman Index of Public Utility Construction Costs ("Handy-Whitman"). The analysis was performed on a consolidated basis across the Company's four jurisdictions.

Q. PLEASE DISCUSS THE RESULTS OF THE MINIMUM-SIZE ANALYSIS.

A. The results of the minimum-size analysis are provided in Schedule TSL-5.

- Poles and Fixtures (Account 364): The analysis shows that 53.1 percent of costs are related to minimum sized installations with the remaining portion related to serving customer maximum demands.
- Overhead conductors and devices (Account 365): The analysis shows that 12.8 percent of costs are related to minimum sized installations with the remaining portion related to serving customer maximum demands.
- Underground Conduits (Accounts 366): The analysis shows that 100.0 percent of costs are related to minimum sized installations.

[9] NARUC Electric Utility Cost Allocation Manual, Pg. 90

- Underground Conductors and Devices (Accounts 367): The analysis shows that 44.6 percent of costs are related to minimum sized installations with the remaining portion related to serving customer maximum demands.
- Line Transformers (Account 368): The analysis shows that 43.0 percent of costs are related to minimum sized installations with the remaining portion related to serving customer maximum demands.

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 customer's 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.

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 PROCESS USED TO ALLOCATE PRODUCTION PLANT.

A. Production plant is the largest component of the Company's rate base, representing 44.4 percent of total utility plant. Production plant costs are incurred consistent with the Company's design of its production facilities to meet both energy and peak demand requirements. Thus, a portion of production plant is related to producing energy and a portion of production plant is related to meeting peak demand requirements. The approach used in this study to allocate production plant was the Average and Excess (A&E) method since it is consistent with how costs are incurred by the Company, allocating a portion of production plant based on energy consumption and the remaining portion based on peak demands. Specifically, the energy portion of plant costs is allocated to each rate class based on average kWh sales throughout the year, while peak demands are based on the difference between peak kW demands and average demands throughout the year. Consistent with the most recent filed CCOS, the Company used the sum of monthly NCPs (12NCP) to represent peak demand since production capacity need is largely driven by peak demands throughout the year rather than in any one particular season or month.

Q. PLEASE DESCRIBE THE PROCESS USED TO DEVELOP THE A&E ALLOCATOR.

A. Rather than assign production plant based on either energy consumption or peak demand, the A&E 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.[10] 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.[11] 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.[12] Thus, using the CP demands approach is contrary to the 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. The NCP demands in this study are based on an average of the twelve-monthly NCP demands (12NCP).

The A&E allocator was 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

[10] NARUC Electric Utility Cost Allocation Manual at pg. 49-52.
[11] Id. at pg. 50.
[12] 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."

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 A&E ALLOCATOR IN THIS STUDY USE 12NCP?

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 6.

Figure 6: 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	1,143	1,653	7	-	134	1,511	75.6%	1,285
Feb	1,066	1,586	74	-	134	1,377	77.4%	1,275
Mar	887	1,660	-	174	131	1,355	65.5%	1,192
Apr	751	1,530	130	326	128	947	79.3%	1,334
May	862	1,560	100	189	128	1,143	75.4%	1,279
Jun	1,050	1,486	174	7	122	1,183	88.7%	1,353
Jul	1,091	1,497	163	-	122	1,212	90.0%	1,376
Aug	1,098	1,459	201	-	122	1,136	96.6%	1,421
Sep	1,020	1,568	92	-	122	1,354	75.3%	1,234
Oct	786	1,589	71	331	128	1,059	74.2%	1,316
Nov	864	1,570	90	216	131	1,133	76.3%	1,301
Dec	1,098	1,616	44	-	134	1,437	76.4%	1,277
Total	11,716	18,774	1,148	1,242	1,536	14,848	78.9%	1,304

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 7 shows the results of the A&E method.

Figure 7: 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 (%)	Total Allocator (%)
RG-Residential	502,707	204,996	297,710	39.90%	56.79%	47.51%
CB-Commercial	83,218	38,826	44,391	7.56%	8.47%	7.97%
SH-Small Heating	21,343	10,422	10,921	2.03%	2.08%	2.05%
GP-General Power	184,960	106,226	78,734	20.67%	15.02%	18.13%
SC-P PRAXAIR Transmission	8,421	8,210	211	1.60%	0.04%	0.90%
TEB-Total Electric Bldg	78,027	43,933	34,094	8.55%	6.50%	7.63%
PFM-Feed Mill/Grain Elev	195	52	143	0.01%	0.03%	0.02%
LP-Large Power	147,847	96,700	51,147	18.82%	9.76%	14.74%
MS-Miscellaneous	17	17	0	0.00%	0.00%	0.00%
SPL-Municipal St Lighting	5,748	2,749	3,000	0.53%	0.57%	0.55%
PL-Private Lighting	4,488	1,585	2,904	0.31%	0.55%	0.42%
LS-Special Lighting	1,077	94	983	0.02%	0.19%	0.09%
Total	1,038,048	513,810	524,238	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 47.51 percent based on the A&E method, representing a composite of their average demand of 39.90 percent and their peak demand of 56.79 percent.

The A&E method in this study varies slightly from the method filed in the Company's most recent rate case. The allocation of excess demand in this study is based on the difference between peak demand and average demand for each rate class. The allocation of excess demand in the prior study was based on the difference between total system peak demand and total system average demand. The allocation of excess demand in this study is consistent with the methodology described in the NARUC Manual and the principles of the A&E method.

Q. PLEASE DESCRIBE THE PROCESS USED TO ALLOCATE TRANSMISSION PLANT.

A. Transmission plant represents 13.8 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,[13] and is consistent with the methodologies described in the Company's prior rate case filing.[14]

Q. PLEASE DESCRIBE THE PROCESS USED TO ALLOCATE DISTRIBUTION PLANT.

A. Distribution plant is the second largest component of rate base representing 36.2 percent of total utility plant. 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 customer portion of distribution plant is allocated to each rate class based on the number of customers. The demand portion of distribution plant costs are allocated based on the rate class's NCP demands. The demand portion is based on an average of 6-month NCP demands (6-NCP) to reflect that the distribution plant is designed to meet customer winter (December through February) and summer (June through August)

[13] NARUC Electric Utility Cost Allocation Manual, Pg. 79

[14] File No. ER-2014-0351, *In the Matter of The Empire District Electric Company for Authority to File Tariffs Increasing Rates for Electric Service Provided to Customers in the Company's Missouri Service Area.*

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 1-month NCP demands (December).[15] The Company believes that the proposed 6-NCP better reflects the design of the distribution system to meet summer as well as winter customer peak demands.

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.

- Meters 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.
- Services 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

[15] File No. ER-2014-0351, *In the Matter of The Empire District Electric Company for Authority to File Tariffs Increasing Rates for Electric Service Provided to Customers in the Company's Missouri Service Area.*

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[16] 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.

[16] NARUC Electric Utility Cost Allocation Manual, Pg. 105

VI. 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.[17]

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

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.

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

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 Sheri Richard, which indicates a total revenue requirement of $564.7 million. The total revenue requirement was then reduced by revenues other than base rates to calculate base rate revenue requirements of $486.6 million.

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.

VII. 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 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, Miscellaneous Service, Municipal Street Lighting, and Special Lighting 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 Residential, Miscellaneous Service, Municipal Street Lighting, and Special Lighting rate classes required higher increases relative to the system average to achieve the system rate of return.
- Based on these results, 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 revenues were increased by 3.50 percent for those rate classes whose current rates recover more than 110.0 percent of their cost of service. This step ensures that the rate increase for these rate classes is less than the overall rate increase.
- In the second step, the proposed revenues were increased by 4.75 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 third step, the proposed revenue increase was capped at approximately 5.75 percent for those rate classes that would require significant increases to achieve the system rate of return. This step ensures that no rate class receives an increase more than 5.75 percent to address continuity and gradualism concerns.
- In the fourth and final step, the remaining revenue deficiency was assigned to all other rate classes in proportion to their current revenues. This step represents those rate classes whose current rates recover slightly more or less than their cost of service. The rate increase to these rate classes was slightly less than the overall revenue increase.

Q. PLEASE DESCRIBE THE PROPOSED RATE DESIGN FOR THE RESIDENTIAL RATE CLASS.

A. The proposed RG rates were based on a revenue requirement of $228.7 million, which represents an increase of $5.5 million. The proposed rates were based on 1.6 million bills and 1.7 million MWH sales.

The proposed customer charge of $19.00 per month is consistent with the underlying cost of service, as shown in Schedule TSL-10. The Schedule shows basic customer-related costs of $28.95 per customer per month, and fully-load customer-related costs of $53.81. The proposed residential customer charge is comparable to residential customer charges at other electric utilities in Missouri, as shown in Figure 8, recognizing however, that many of the other electric utilities are cooperatives. The Figure shows the average monthly residential customer charge in Missouri is $25.43 per customer.

Figure 8: Missouri Electric Utility Customer Charges

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
Ozark Border Electric Coop	25.00
Black River Electric Coop - (MO)	25.00
Farmers Electric Coop, Inc - (MO)	25.00
Platte-Clay Electric Coop, Inc	25.38
Boone Electric Coop	26.95
Laclede Electric Coop, Inc	27.00
Ozark Electric Coop Inc - (MO)	27.50
Citizens Electric Corporation - (MO)	29.00
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	$ 25.43

The revenue requirement not recovered through the customer charge is recovered from winter volumetric charges of $0.12754 per kWh for first 600 kWh of usage and $0.10369 per kWh for all additional usage and summer volumetric charges of $0.12754 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 an average monthly bill, including FAC, of a RG customer by $8.02 per month, or 5.8 percent.[18]

Q. PLEASE DESCRIBE THE PROPOSED RATE DESIGN FOR THE C&I RATE CLASSES.

A. The proposed rate design for C&I rate classes is described below.

<u>Commercial General</u>

The proposed rates were based on a revenue requirement of $45.7 million, which represents an increase of 1.0 million. The proposed rates were based on 216,864 bills and 316,607 MWH.

The proposed customer charge of $25.00 per month is consistent with the underlying cost of service, as shown in Schedule TSL-10. The Schedule shows basic customer-related costs of $32.61 per customer per month, and fully-load customer-related costs of $55.67.

The revenue requirement not recovered through the customer charge is recovered from winter volumetric charges of $0.13326 per kWh for first 700 kWh of usage and $0.11980 per kWh for all additional usage and summer volumetric charges of $0.13326

[18] Based on an average monthly bill for a Residential General customer using 12,772 kWh per year, including EECR of $0.00039 per kWh.

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

Small Heating

The proposed rates were based on a revenue requirement of $10.5 million, which represents an increase of $0.2 million. The proposed rates were based on 36,336 bills and 84,989 MWH.

The proposed customer charge of $25.00 per month is consistent with the underlying cost of service, as shown in Schedule TSL-10. The Schedule shows basic customer-related costs of $32.44 per customer per month, and fully-load customer-related costs of $55.21.

The revenue requirement not recovered through the customer charge is recovered from winter volumetric charges of $0.12987 per kWh for first 700 kWh of usage and $0.09702 per kWh for all additional usage and summer volumetric charges of $0.12987 per kWh for all kWh usage. The proposed rate design and bill impact analyses are included in Schedule TSL-10.

General Power

The proposed rates were based on a revenue requirement of $87.7 million, which represents an increase of $0.2 million.

The proposed rate design includes only an increase in the customer charge to $80.0, and no increase in the kW facility demand charges, kW billed demand charges, and kWh volumetric charges. The proposed rate design and bill impact analyses are included in Schedule TSL-10.

SC-P and ST

The proposed rates within these tariffs are based on the proposed revenue requirement, and the proposed rate design reflects approximately a proportional increase in rate elements. Any differences between actual contract revenue and the proposed rates in these tariffs have not been allocated to other customers. Instead, the Company is proposing to voluntarily impute the revenue difference under these contracts to these classes.

<u>Total Electric Building</u>

The proposed rates were based on a revenue requirement of $37.5 million, which represents a decrease in revenue requirements of $0.02 million. The proposed rate design reflects an increase in customer charge to $72.00 and a proportional decrease in other rate elements. The proposed rate design and bill impact analyses are included in Schedule TSL-10.

<u>Feed Mill and Grain Elevator Service</u>

The proposed rates were based on a revenue requirement of $74,388, which represents a decrease in revenue requirements of $774. The proposed rate design reflects an increase in customer charge to $28.5, and a proportional decrease in rate elements.

<u>Large Power</u>

The proposed rates were based on a revenue requirement of $65.3 million, which represents an increase of $1.6 million.

The proposed rate design includes an increase in the customer charge and facility kW demand charges and no increase in the kWh volumetric charges or kW billed demand charges. Presently, the Large Power rate class recovers 32.2 percent of its cost of service through kW demand charges while demand costs represent 52.7 percent of the cost of service. Furthermore, the current facility demand charges represent 15.2 percent of total demand charge revenues while facility demand costs represent 39.0 percent of demand-related costs.

The proposed rate design recovers 33.9 percent of its cost of service through kW demand charges – a movement that better reflects the proportion of demand-related costs – of which 21.5 percent is recovered through facility demand charges – a movement that better reflects facility demand-related costs. The proposed rate design and bill impact analyses are included in Schedule TSL-10.

Miscellaneous Service

The proposed rates were based on a revenue requirement of $15,441, which represents an increase in revenue requirements of $613. The proposed rate design reflects approximately a proportional increase in rate elements.

Q. PLEASE DESCRIBE THE PROPOSED RATE DESIGN FOR THE LIGHTING RATE CLASSES.

A. The proposed rate design for Lighting rate classes is described below.

Municipal Street Lighting

The proposed rates were based on a revenue requirement of $2.4 million, which represents an increase of $0.1 million. The rates for each lamp size and type were increased on an equal percentage basis.

Private Lighting

The proposed rates were based on a revenue requirement of $4.2 million, which represents an increase of $0.01 million. The rates for each lamp size and type were increased on an equal percentage basis.

<u>Special Lighting</u>

The proposed rates were based on a revenue requirement of $139,978, which represents an increase of $4,592. The volumetric rates per kWh were increased on an equal percentage basis.

Q. HAVE YOU EXAMINED THE IMPACT OF YOUR PROPOSED CHANGES IN 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 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 Energy Efficiency Cost Recovery ("EECR") charge, and (ii) the current base rates plus Fuel Adjustment Clause ("FAC") charge, EECR charge, and Tax Reform Credit. This provides a more accurate assessment of bill impact resulting from Company's proposal to include FAC and Tax Reform Credit in the proposed base rates.

Q. WHAT IS THE MONTHLY BILL IMPACT FOR RESIDENTIAL AND COMMERCIAL CUSTOMERS?

A. Figure 9 shows the annual bill impact for the residential and commercial customer classes. The Figure shows the proposed base rates will increase an average monthly bill for a RG customer by $8.02 per month, or 5.8 percent.[19]

Figure 9: Bill Impact Analysis

The Empire District Electric Company
Schedule 3, Page 1 of 1
4 CSR 240-3.030(3)(B)(3)(4)(5)

Class	Average Customer Count	Average Annual Customer Impact: Bill Change $	[1] Average Annual Customer Impact: Bill Change %	Aggregate Annual Change	[1] Aggregate Annual % Change
RG-Residential	130,887	$ 96.24	5.8%	$ 12,596,881	5.8%
CB-Commercial	18,072	$ 125.82	5.2%	$ 2,273,755	5.2%
SH-Small Heating	3,028	$ 164.22	5.0%	$ 497,260	5.0%
GP-General Power	1,793	$ 1,476.02	3.1%	$ 2,646,498	3.1%
SC-P PRAXAIR Transmission	1	$ 212,414.31	5.1%	$ 212,414	5.1%
TEB-Total Electric Bldg	946	$ 1,172.45	3.0%	$ 1,109,335	3.0%
PFM-Feed Mill/Grain Elev	10	$ 115.67	1.6%	$ 1,157	1.6%
LP-Large Power	40	$ 81,320.65	5.2%	$ 3,246,049	5.2%
MS-Miscellaneous	3	$ 282.94	5.8%	$ 849	5.8%
SPL-Municipal St Lighting	7	$ 29,358.47	9.4%	$ 205,509	9.4%
PL-Private Lighting	252	$ 553.88	3.4%	$ 139,347	3.4%
LS-Special Lighting	126	$ 72.13	6.9%	$ 9,076	6.9%
Total Customers	155,165			$ 22,938,132	4.9%

VIII. INCLINING BLOCK RATES

Q. DOES THE COMPANY CURRENTLY UTILIZE INCLINING BLOCK RATES FOR ITS RESIDENTIAL CLASS?

A. No. In the Company's last rate case, however, the parties agreed "to work together to develop an analysis regarding responsible energy use as related to residential block rates, with the analysis to be filed by the Company as part of its direct testimony in the

[19] Based on an average monthly bill for a Residential General customer using 12,772 kWh per year, including EECR Charge of $0.00039 per kWh.

Company's next general rate case." This agreement (the "Block Rates Provision") was part of the Stipulation and Agreement filed on June 20, 2016 in Case No. ER-2016-0023. The Commission's Order Approving Stipulation and Agreement was issued on August 10, 2016.

Q. HAS THE COMPANY COMPLIED WITH THE BLOCK RATES PROVISION?

A. Yes. It is my understanding that the Company discussed inclining bock rates and other rate design options regarding energy use as related to residential block rates at various meetings leading up to the filing of this rate case.

The Company prepared analysis of residential rate design alternatives that included Summer-season inclining or inverted block rates, similar to the Summer-season inclining block rates approved by the Commission for one of the Company's affiliated Missouri gas utilities, Liberty Utilities (Midstates Natural Gas) Corp. Presently, the Company's Summer-season rates are flat.

In addition, the Company prepared analysis of Winter-season declining block rates that have a flatter slope; i.e., a smaller differential between the head block and tail block rates, which represents a step toward inclining block rates while addressing continuity and gradualism considerations. The results of the analysis of the residential rate design alternatives are included in Schedule TSL-10, pages 3 and 4. It is my understanding that these rate design alternatives were discussed with Staff, OPC, and DE during one of the stakeholder meetings referenced above.

Q. IS THE COMPANY PROPOSING TO IMPLEMENT THE RESIDENTIAL RATE DESIGN ALTERNATIVES WHICH WERE DEVELOPED AS PART OF THE DISCUSSIONS REGARDING THE BLOCK RATES PROVISION?

A. No, the Company believes that these residential rate design alternatives are too limited and that better alternatives will be available following implementation of the Company's planned investment in Advanced Metering Infrastructure ("AMI").

Q. WILL A MOVEMENT TO INVERTED BLOCK RATES BETTER PROMOTE ENERGY EFFICIENCY?

A. Not necessarily. Any change from the Company's current rate structure to an inverted block structure will require a meaningful increase in tail block rates and/or a meaningful decrease in the head block rates. While the relative price increase in the tail block rates will likely have the effect of encouraging reductions in consumption and/or adoption of energy efficient technologies by customers who consume at the margin in the tail block, the relative price decrease in the head block rates will likely have the opposite effect. Thus, the net effect of the rate change is uncertain, and depends on the magnitude of the relative price increases and price decreases as well as the relative price responsiveness of high-use and low-use customers.

Q. WILL A MOVEMENT TO INVERTED BLOCK RATES BETTER ALIGN RATES WITH COSTS?

A. Not necessarily. The Company does not have sufficient information to know whether inverted block rates better reflect a movement toward the underlying cost of service. To determine that, the Company would need an understanding of the unit costs for customers of various sizes and to compare those unit costs with their rates at various consumption levels. This requires both energy and demand data to evaluate the unit cost at various consumption levels.

Q. WILL A MOVEMENT TO INVERTED BLOCK RATES CREATE A CONCERN REGARDING CUSTOMER BILL IMPACTS?

A. Possibly. The primary customer bill impact concern are high-use customers with significant tail block usage.

Q. PLEASE DESCRIBE THE RATE DESIGN ALTERNATIVES THAT WILL BE AVAILABLE FOLLOWING THE COMPANY'S PLANNED INVESTMENT IN AMI.

A. The Company's planned investment in AMI provides a platform to implement a much broader set of residential rate design alternatives than has been the case in the past. Many of these alternatives go far beyond what can be achieved with inverted block rates – and represent the principle reason the Company does not propose inverted block rates in this proceeding.

Specifically, AMI supports a wide variety of rate design alternatives that have been developed and implemented by utilities throughout the U.S. Such rate design alternatives are discussed below.[20]

- Time-of-Use ("TOU") rates – customer usage during the day is divided into time periods (peak and off-peak periods) with a schedule of rates for each period. Prices are higher during the peak period and lower during the off-peak period, mirroring the average variation in the cost of supply. At least one utility has moved towards TOU rates as the default rate for residential customers;[21]

[20] See "Time-Varying and Dynamic Rate Design", The Regulatory Assistance Group (RAP) and The Brattle Group, July 2012.
[21] See Sacramento Municipal Utilities District ("SMUD") who utilizes Time-of-Day (5-8 p.m.) rates as the standard rate for all residential customers: https://www.smud.org/en/Rate-Information/Residential-rates

- Critical Peak Pricing ("CPP") rates – customers pay a higher price during the few days of the year when wholesale prices are the highest or when the power grid is severely stressed (i.e., typically up to 15 days per year during the peak season). Customers receive a discount off the standard tariff price during other hours of the season or year;
- Peak Time Rebate – customers receive a rebate for load reductions (estimated relative to a forecast of what they otherwise would have consumed). There is no rate discount during non-event hours.
- Real time pricing – customers pay for energy at a rate that is linked to the hourly market price for electricity. Participants are made aware of hours prices on either a day-ahead or hour-ahead basis;

In addition, some utilities offer three-part rate plans that include a customer charge, energy charge, and peak hour or demand charge.[22]

Q. IS THE COMPANY PROPOSING ANY OF THESE ALTERNATIVE RATE DESIGNS AT THIS TIME?

A. No, the rate design alternatives discussed above (as well as potentially others) require installation of AMI/ smart meters (or at least programmable TOU meters for TOU rates). Following implementation of AMI, the Company will have data necessary to evaluate, design and implement these types of rate design alternatives. Thus, the Company believes it is better to take a more comprehensive review and evaluation of rate design alternatives instead of implementing inverted block rates in this proceeding.

[22] See Arizona Public Service (APS) who offers a three-part rate under its "Saver Choice Plus" price plan: https://www.aps.com/en/residential/accountservices/serviceplans/Pages/saver-choice-plus.aspx

Q. DO THE RATE DESIGN ALTERNATIVES DISCUSSED ABOVE PROVIDE A BETTER OPPORTUNITY TO PROMOTE ENERGY EFFICIENCY AND ALIGN RATES WITH COSTS?

A. Yes. Potential benefits of time-varying rates include: (1) avoided or deferred resource costs – time-varying rates encourage customers to shift consumption away from prices that are higher during the peak hours, and thereby reduce system peak demand; (2) fairness in retail pricing – time-varying rates better align rates with the underlying cost of service; and (3) facilitating deployment of distributed resources – time-varying rates improve the economic attractiveness of certain types of distributed resources, such as rooftop solar and energy storage.[23]

While TOU rates have been widely used over the past decades, their adoption has greatly expanded with the increased installation of AMI/ smart meters.

IX. MISSOURI JURISDICTION CASH WORKING CAPITAL ("CWC") REQUIREMENT

Q. HAVE YOU PREPARED SCHEDULES TO SUPPORT YOUR LEAD LAG STUDY?

A. Yes. Schedules TSL-11 and TSL-12 summarize the results of the lead-lag study and supporting schedules. The Schedules were prepared by me or under my direction.

Q. PLEASE DEFINE THE TERM "CASH WORKING CAPITAL" AS A RATE BASE COMPONENT.

[23] See "Time-Varying and Dynamic Rate Design", The Regulatory Assistance Group (RAP) and The Brattle Group, July 2012, pgs. 9-10.

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 the lead-lag study include: O&M expenses, including labor and non-labor expenses; federal, state, and local taxes; and employment taxes.

Q. HOW DID YOU DETERMINE THE CWC REQUIREMENT?

A. The CWC requirement was based on the results of a lead-lag study, which compares the net difference between the revenue lag and expense lead. The revenue lag represents the number of days from the time customers receive their electric service to the time customers pay for electric 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 electric 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 lead-lag days were then applied to the Company's adjusted test year expenses to derive the CWC requirement, which was included in the Company's rate base.

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 actual CWC needs during the test year for the Company's Missouri jurisdiction. Furthermore, the methods used to conduct the lead-lag study in this filing are generally consistent with those filed with the Commission in the Company's most recent rate case.[24] The lead-lag study in this filing is based on financial data for all of the Company's four jurisdictions (i.e., Arkansas, Kansas, Missouri and Oklahoma), as described below, while the lead-lag study in the Company's most recent rate case was based on a previous study conducted for the Company's Missouri jurisdiction.

X. LEAD-LAG STUDY APPROACH

Q. PLEASE SUMMARIZE THE RESULTS OF THE LEAD-LAG STUDY.

A. The results of the lead-lag study are summarized in Schedule TSL-11 and show a net CWC requirement of negative approximately $1.1 million for the Company's Missouri jurisdiction for the period April 1, 2018 through March 31, 2019. The lead-lag study relied on data provided by the Company for its four jurisdictions (i.e., Arkansas, Kansas, Missouri and Oklahoma). The lead-lag study was based on data for the period July 1, 2017 through June 30, 2018.

Q. PLEASE DESCRIBE DEVELOPMENT OF 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 electric service is provided to customers to the time payment is received from customers. The expense leads measure the number of days from the time goods and services used to

[24] File No. ER-2014-0351, *In the Matter of The Empire District Electric Company for Authority to File Tariffs Increasing Rates for Electric Service Provided to Customers in the Company's Missouri Service Area.*

provide electric service are provided to the Company to the time payments are made by the Company for those goods and services. The lag and leads are measured in days for individual expenses, converted to "dollar-days" that reflect a weighting by expense amount, and then summed across all expenses.

A. Revenue Lag

Q. PLEASE DESCRIBE THE REVENUE LAG.

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

Q. WHAT IS THE SERVICE LAG?

A. The service lag measures the average number of days in the service period; i.e., the time between the start and end of the billing month. The point in time at which meters are read indicates the end of the billing month. The service lag in this lead-lag study was based on the midpoint of the service period, which reflects that electricity is delivered evenly over the service period.

Q. WHAT IS THE BILLING LAG?

A. The billing lag measures the number of days from the time meters are read to the time bills are recorded and sent to customers. The billing lag includes time for review and validation of billed usage and dollars. The billing lag was based on the Company's customer billing data.

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. HOW WERE LAG DAYS DETERMINED FOR REVENUES?

A. The revenue lag was based on the sum of the revenue lag components discussed above. The supporting workpapers are included in Schedule TSL-12.

B. Expense Lead

1. Purchased Fuel and Power Expenses

Q. HOW WERE LEAD DAYS DETERMINED FOR PURCHASED FUEL AND POWER EXPENSES?

A. Lead days for purchased fuel and power expenses were based on the service lead (i.e., the midpoint of the service period) and payment lead (i.e., the number of days between the end of the service period and payment date). The analysis was based on purchased fuel (coal, natural gas, fuel oil and tires) and purchased power transactions. Lead days were based on the number of days from the midpoint of the service period to the payment date.

2. O&M Expenses

Q. HOW WERE LEAD DAYS DETERMINED FOR O&M EXPENSES?

A. Lead days for O&M expenses were determined by first separating the expenses into four groups: (1) Operations and Maintenance ("O&M") expenses, separated between labor and non-labor expenses; (2) Taxes Other than Income Taxes; (3) Income Taxes, and (4) Interest Payments on long-term debt. The lead days for each group were measured separately.

Q. HOW WERE LEAD DAYS DETERMINED FOR LABOR EXPENSES?

A. Lead days for labor or payroll expenses were based on the Company's salary and wage payment schedule, which pays employees on a bi-weekly basis. The lead days for regular payroll expenses were based on the number of days from the midpoint of the pay period to the payment date.

Q. HOW WERE LEAD DAYS DETERMINED FOR 401-K PAYMENTS?

A. Lead days for 401-K benefits were based on the Company's payment schedule to employees. Payments are made bi-weekly. The lead days for 401-K expenses were based on the number of days from the midpoint of the service period to the payment date.

Q. HOW WERE LEAD DAYS DETERMINED FOR POST-RETIREMENT BENEFITS PAYMENTS?

A. Lead days for post-retirement benefits were based on the Company's payment schedule to retirees and the benefits administrator. Payments were made weekly and bi-monthly. The lead days for post-retirement benefits expenses were based on the number of days from the midpoint of the service period to the payment date.

Q. HOW WERE LEAD DAYS DETERMINED FOR MEDICAL, VISION, AND DENTAL EXPENSES?

A. Lead days for medical, vision, and dental expenses were based on the Company's payment schedule to its service providers. Payments are made weekly and monthly. The lead days for medical, vision, and dental expenses were based on the number of days from the midpoint of the service period to the payment date.

Q. HOW WERE LEAD DAYS DETERMINED FOR LIFE AND ACCIDENTAL DEATH AND DISMEMBERMENT (AD&D) INSURANCE EXPENSES?

A. Lead days for life and AD&D insurance expenses were based on the Company's payment schedule to its insurance providers. Payments are made monthly. The lead days for life and AD&D insurance expenses were based on the number of days from the midpoint of the service period to the payment date.

Q. HOW WERE LEAD DAYS DETERMINED FOR INTERCOMPANY TRANSFERS?

A. Lead days for intercompany transfers were based on the Company's payment schedule. Transfers are made in the month following the service period, which is generally from the middle of a calendar month to the middle of the following calendar month. The lead days for intercompany transfers were based on the number of days from the midpoint of the service period to the payment date.

Q. HOW WERE LEAD DAYS DETERMINED FOR PUBLIC SERVICE COMMISSION ("PSC") ASSESSMENT EXPENSES?

A. Lead days for PSC Assessment were based on the Company's payment schedule for assessment expenses. Payments are made monthly, quarterly, or annually based on state requirements. The lead days for PSC Assessment expenses were based on the number of days from the midpoint of the service period to the payment date.

Q. HOW WERE LEAD DAYS DETERMINED FOR OTHER NON-LABOR O&M EXPENSES?

A. Lead days for Other Non-Labor O&M expenses were based on a stratified sample of invoices paid. The expense lead for each stratum was then calculated and weighed in proportion to the number of transactions in each stratum.

Q. DOES THE SAMPLING METHODODOLGY DIFFER FROM THE APPROACH USED IN THE COMPANY'S PRIOR RATE CASE?

A. Yes, the sampling methodology differs from the approach used in the prior rate case. By developing a stratified sample, the analysis is more representative of Other Non-Labor O&M Expenses for the test year. The study determined the lead days from the date services were provided to the Company to the date payment was made for those services. If no information was available regarding the date services were provided, then the date of the invoice was used.

3. Income Tax Expense

Q. HOW WERE LEAD DAYS DETERMINED FOR FEDERAL AND STATE INCOME TAXES?

A. Lead days for federal and state income taxes were based on the number of days from the midpoint of the applicable tax period to the payment dates. The payment dates were based on quarterly payments on April 15, June 15, September 15, and December 15.

4. Taxes Other than Income Taxes

Q. WHAT TAXES ARE INCLUDED IN THE TAXES OTHER THAN INCOME TAXES?

A. Taxes Other than Income Taxes includes: (1) payroll-related taxes (FICA, Federal Unemployment, State Unemployment, Income Tax withholding); and (2) Property taxes.

Q. HOW WERE LEAD DAYS DETERMINED FOR THOSE TAXES?

A. Lead days for taxes other than income taxes were based on the number of days from the midpoint of the service period to the payment date.

5. Interest Expense

Q. HOW WERE LEAD DAYS DETERMINED FOR INTEREST EXPENSE?

A. Lead days for interest expense were based on actual interest payments in the test year. The lead days are calculated from the midpoint of the period for which the interest was paid to the payment date.

Q. WHAT WERE THE RESULTS OF THE LEAD-LAG STUDY?

A. The CWC requirement for the Company is negative $1.1 million for the Missouri jurisdiction, as shown in Schedule TSL-11.

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 actual CWC needs during the test year. Furthermore, the methods used to conduct this lead-lag study are generally consistent with those previously filed with the Commission.

XI. WEATHER NORMALIZATION RIDER

Q. PLEASE SUMMARIZE THE COMPANY'S PROPOSAL FOR A WEATHER NORMALIZATION RIDER.

A. The Company proposes to implement a Weather Normalization Rider. The Weather Normalization Rider will help to mitigate a basic misalignment between the structure of utility rates and the structure of utility costs. The proposed Weather Normalization Rider is similar to the Weather Normalization Adjustment Rider ("WNAR") approved by the Commission for the Company's Liberty-Midstates Natural Gas division in Missouri.[25]

Electric utility costs are largely fixed and change very little in the short run as usage levels change. However, electric utility rates have a significant variable or consumption-based component that produces revenue changes as kWh consumption changes. The proposed Weather Normalization Rider will help mitigate this misalignment by adjusting customer bills and the Company's revenues for the impact of revenue changes due to weather.

Q. PLEASE EXPLAIN THE MISALIGNMENT BETWEEN ELECTRIC UTILITY COSTS AND RATES.

A. Electric utilities incur three types of costs in providing electric service to customers:

- Fixed costs – including meter, billing and a portion of distribution costs that generally varies by the number of customers;
- Demand-related costs – including transmission and distribution costs that generally varies by demand, and;
- Energy-related costs – including variable O&M expenses that generally varies by kWh sales or energy consumed.

Utility rates are designed to recover all of these costs. However, especially for residential and small commercial customers, a significant portion of the costs are recovered on the basis of kWh consumption charges reflecting usage (based on normal weather) at the time rates are established (*i.e.*, rates are based upon the level of usage embodied in a historical test year). Thus, to the extent that actual usage is significantly

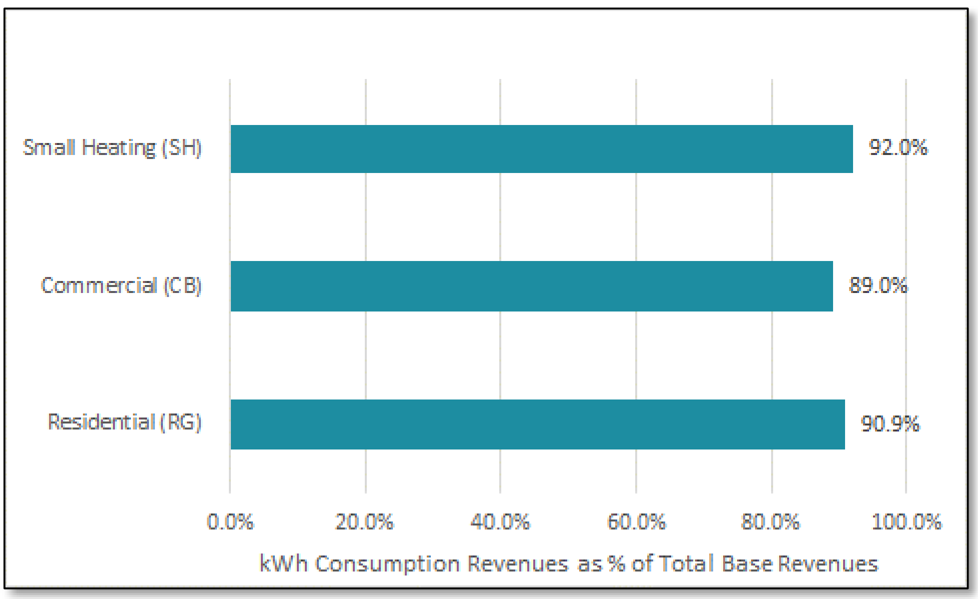
[25] https://missouri.libertyutilities.com/uploads/MO%20Liberty%20Tariff%2004.01.19.pdf

lower than the level assumed in rates, then utility rates no longer recover the cost of service. Conversely, to the extent that actual usage is significantly higher than the amount assumed in rates, then utility rates recover revenues in excess of the cost of service.

Q. DO THE COMPANY'S CURRENT RATES EXHIBIT THIS MISALIGNMENT BETWEEN UTILITY COSTS AND RATES?

A. Yes, the Company's rates exhibit this misalignment between utility rates and costs. The portion of the Company's charges that are based on consumption (or kWh sales) is significant, as shown in Figure 10.

Figure 10: Consumption Revenues as Percentage of Total Revenues



The Figure shows that a significant portion of the Company's residential and commercial base rate revenues are recovered through usage charges. For example, the Figure shows that 90.9 percent of the RG revenue requirement is recovered through consumption charges.

Q. WHY IS THIS MISALIGNMENT A PROBLEM?

A. The misalignment between utility rates and costs is a problem for two reasons. First, increases or decreases in consumption will likely cause utilities to over- or under-collect their cost of service. Warmer than normal weather during the winter, for example, will likely result in sales that are below historical test year sales, reducing the likelihood that utilities recover their Commission-authorized cost of service. Conversely, colder than normal weather during the winter will likely result in sales that are above historical test year sales, increasing the likelihood that utilities recover more than their Commission-approved cost of service.

Second, the mismatch between utility rates and costs also creates bill volatility for customers since customer bills are lower in warmer than normal weather during the winter and higher in colder than normal weather during the winter.

Q. HOW IS THE PROPOSED WEATHER NORMALIZATION RIDER A SOLUTION TO THE MISMATCH BETWEEN UTILITY COSTS AND RATES?

A. The Weather Normalization Rider is a "partial" solution to the mismatch between utility rates and costs because it separates or 'decouples' the weather portion of the relationship between the amount of electricity delivered by a utility and the revenues it receives from such delivery. Thus, changes in the Company's kWh sales due to weather do not lead to an under- or over-collection of costs.

Q. YOU MENTIONED THAT THE WEATHER NORMALIZATION RIDER IS A "PARTIAL" SOLUTION TO THE MISMATCH BETWEEN UTILITY RATES AND COSTS. WHAT FACTORS OTHER THAN WEATHER CONTRIBUTE TO CHANGES IN UTLITY SALES AND REVENUES?

A. The Weather Normalization Rider is only a "partial" solution to the mismatch between utility rates and costs because the Rider mitigates only changes in utility sales and revenues due to weather. Other factors that result in changes in utility sales include energy conservation, installation of energy efficiency measures, and installation of Solar PV. The Weather Normalization Rider does not mitigate the impact of those factors on changes in utility sales and revenues.

Q. ARE THERE MECHANISMS THAT ADDRESS THESE FACTORS THAT CONTRIBUTE TO CHANGES IN UTILITY SALES AND REVENUES?

A. Yes, revenue decoupling mechanisms address weather as well as other factors that contribute to changes in utility sales and revenues. While there are many variations of revenue decoupling mechanisms, most mitigate the impact of changes in sales and revenues due to energy conservation, installation of energy efficiency measures, and installation of Solar PV.

Q. PLEASE PROVIDE A BRIEF DESCRIPTION OF THE WEATHER NORMALIZATION RIDER BEING PROPOSED BY THE COMPANY IN THIS CASE.

A. The Weather Normalization Rider adjusts customer bills for variations from normal weather since the Company's rates are designed based on customer consumption under normal weather conditions. Normal weather is measured based on Heating Degree Days ("HDD") during the heating season, and Cooling Degree Days ("CDD") during the cooling season.

For bills during the heating season, warmer than normal temperatures would result in a surcharge or increase to the bill (when bills are otherwise lower due to warmer weather), while colder than normal temperatures would result in a credit or reduction to the bill (when bills are otherwise higher due to colder weather). In this manner, the surcharge and credit would help stabilize customer bills and the Company's revenues.

For bills during the cooling season, warmer than normal temperatures would result in a credit or reduction to the bill (when bills are otherwise higher due to warmer weather), while cooler than normal temperatures would result in a surcharge or increase to the bill (when bills are otherwise lower due to mild weather). In this manner, the surcharge and credit would help stabilize customer bills and the Company's revenues.

Q. HOW WOULD THE COMPANY CALCULATE THE SURCHARGE AND CREDIT?

A. The Company proposes to calculate a surcharge or credit on a 'real time' basis for each customer – i.e., at the time the Company calculates the customer's bill. In this manner, the time period used to calculate the surcharge or credit is concurrent with the customer's billing cycle. Moreover, the surcharge or credit reflects the specific impact of the customer's variation in weather. For bills during the heating season, warmer than normal temperatures would result in a surcharge or increase to the bill (when bills are otherwise lower due to warmer weather).

Q. WHAT ARE THE BENEFITS OF THE WEATHER NORMALIZATION RIDER?

A. There are two primary benefits associated with the Weather Normalization Rider. First, the Rider promotes bill stability for customers. Customers pay no more or less than the amount they would have paid under normal weather conditions. The Rider formula reflects the relative difference between actual and normal HDDs in the heating season and actual and normal CDDs in the cooling season.

The second benefit is that the Rider promotes revenue stability for the Company. Similar to the customer benefits, the Company receives base rate revenues that are no more or less than the amount they would have received under normal weather conditions.

Q. DO OTHER UTILITIES EXPERIENCE SIMILAR OVER- AND UNDER-RECOVERY OF COSTS?

A. Yes. This type of over- and under-collection of costs is not unique to the Company. Multiple states have implemented weather normalization mechanisms (and the more comprehensive revenue decoupling mechanisms) to address this issue. According to the ACEEE 2018 Scorecard, sixteen states have implemented revenue decoupling mechanisms for electric utilities, with another fifteen states having a form of partial decoupling, known as a "Lost Revenue Adjustment Mechanism (LRAM")."[26]

Q. PLEASE DESCRIBE HOW THE COMPANY'S PROPOSED WEATHER NORMALIZATION RIDER WILL OPERATE?

A. The proposed Rider will calculate for each customer in each month and in each billing cycle the difference between: (a) base rate revenues that were based on actual sales ("Actual Base Rate Revenues") and (b) base rate revenues that would have been billed based on weather normalized sales ("Weather-Normalized Normal Base Rate Revenues"). Customers will receive a credit when Actual Revenues exceed Normal Revenues, and a surcharge when Actual Revenues are less than Normal Revenues.

[26] LRAM is a ratemaking mechanism designed to allow utilities to recover the revenue deficiency associated with a decline in sales due to energy efficiency programs.

Weather normalized sales reflect actual sales, adjusted for the relative difference between actual and normal HDDs in the heating season and actual and normal CDDs in the cooling season.

Q. WILL THE PROPOSED RIDER ADJUST THE COMPANY'S REVENUE REQUIREMENT?

A. No. The proposed Rider does not adjust the Commission-authorized revenue requirements. The revenue requirements will continue to be set by the Commission in ratemaking proceedings. The proposed Rider helps to provide the Company with an opportunity to achieve the revenues established and approved during its ratemaking proceedings and is reasonably designed to provide the Company with a sufficient opportunity to earn a fair return on equity.

Q. MISSOURI LAW ALLOWS A WEATHER NORMALIZATION MECHANISM TO APPLY ONLY TO THE RESIDENTIAL CLASS AND CLASSES THAT ARE NOT DEMAND METERED. IS THE COMPANY'S PROPOSED RIDER IN COMPLIANCE WITH THIS STATUTORY REQUIREMENT?

A. Yes, the rider is in compliance with this requirement imposed by RSMo. 386.266.

Q. MISSOURI LAW REQUIRES A WEATHER NORMALIZATION MECHANISM TO CONTAIN PROVISIONS FOR AN ANNUAL TRUE-UP WHICH SHALL ACCURATELY AND APPROPRIATELY REMEDY ANY OVER- OR UNDER-COLLECTIONS, INCLUDING INTEREST AT THE UTILITY'S SHORT-TERM BORROWING RATE, THROUGH SUBSEQUENT RATE ADJUSTMENTS OR REFUNDS. IS THE COMPANY'S PROPOSED RIDER IN COMPLIANCE WITH THIS STATUTORY REQUIREMENT?

A. Yes, the rider is in compliance with this requirement imposed by RSMo. 386.266.

Q. MISSOURI LAW REQUIRES QUARTERLY SURVEILLANCE REPORTS IN CONNECTION WITH ANY WEATHER NORMALIZATION MECHANISM. IS THE COMPANY'S PROPOSED RIDER IN COMPLIANCE WITH THIS STATUTORY REQUIREMENT?

A. Yes, the rider is in compliance with this requirement imposed by RSMo. 386.266.

Q. PLEASE SUMMARIZE THE BENEFITS OF THE PROPOSED WEATHER NORMALIZATION RIDER.

A. The proposed Weather Normalization Rider stabilizes customer bills and revenues over time resulting in benefits to both the Company and its customers since it corrects for the mismatch between utility rates and costs. The primary benefits of the Rider are:

- Stabilizes customer bills on a real-time basis;
- Provides the Company with a more stable stream of revenues on a real-time basis; and
- Improves the Company's ability to recover its cost of service.

XII. <u>CONCLUSION</u>

Q. **DOES THIS COMPLETE YOUR DIRECT TESTIMONY?**

A. Yes, it does.

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Summary

Tim Lyons is a partner with ScottMadden with more than 30 years of experience in the energy industry. Tim has held senior positions at several gas utilities and energy consulting firms. His experience includes rate and regulatory support, sales and marketing, customer service and strategy development. Prior to joining ScottMadden, Tim was Vice President of Sales and Marketing for Vermont Gas. He has also served as Vice President of Marketing and Regulatory Affairs for Providence Gas Company, Director of Rates at Boston Gas Company, and Project Director at Quantec, LLC, an energy consulting firm.

Tim has sponsored testimony before 17 state regulatory commissions. Tim holds a B.A. from St. Anselm College, an M.A. in Economics from The Pennsylvania State University, and an M.B.A. from Babson College.

Areas of Specialization

- Regulation and Rates
- Retail Energy
- Utilities
- Natural Gas

Capabilities

- Regulatory Strategy and Rate Case Support
- Strategic and Business Planning
- Capital Project Planning
- Process Improvements

Articles and Speeches

- "Country Strong: Vermont Gas shares its comprehensive effort to expand natural gas service into rural communities." ***American Gas Association***, June 2011 (with Don Gilbert).
- "Talking Safety With Vermont Gas." ***American Gas Association***, February 2009 (with Dave Attig).
- "Consumers Say 'Act Now' To Stabilize Prices." ***Power & Gas Marketing***, September/ October 2001 (with Jim DeMetro and Gerry Yurkevicz).
- "Rate Reclassification: Who Buys What and When." ***Public Utilities Fortnightly***, October 15, 1991 (with John Martin).

Recent Assignments

- Sponsored cost of service/rate design testimony for a Mid-Atlantic gas utility. Testimony included a proposal for new residential and commercial rate classes and introduction of a block break rate design.
- Sponsored cost of service/rate design testimony for a Midwest gas utility. Testimony included a proposal for new commercial rate classes and a revenue decoupling mechanism.
- Sponsored cost of service/ rate design and lead-lag testimony for a Midwest gas utility. The testimony included proposals for Revenue Decoupling/ Weather Normalization Mechanism and Tracker Accounts for certain O&M expenses and capital costs.
- Sponsored rate design testimony for a Northeast gas utility. The testimony included: a proposal for zonal rates to promote expansion of natural gas service in the state; market analysis; and financial modeling.
- Led a study for the Massachusetts Department of Energy Resources to evaluate the benefits, costs and policies options associated with natural gas expansion by Massachusetts gas utilities. The study included: (a) research on state regulatory policies; (b) financial modeling and analysis of the economic and environmental impacts of pursuing various policy options; and (c) a survey of Massachusetts homeowners on their opinion of home heating fuels.
- Prepared a transmission and distribution (T&D) avoided cost study and report for a Midwest electric utility. The study was used to support the utility's energy efficiency programs.
- Prepared a review and evaluation of cost of service/ rate design studies for an electric utility. The assignment included review of proposed rate designs that address cost shifting concerns with serving residential distribution generation customers through introduction of higher customer charges, a demand charge and time-of-use energy charges.

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- Assisted in the development of an electric portfolio of cost of service, rate design, and rate planning tools. The tools were used to evaluate the impact of future rate filings and resource portfolio decisions on individual rate classes.
- Prepared a market analysis for a utility to evaluate natural gas expansion into new areas, including: (a) survey of homes and businesses; (b) estimate of construction and operating costs; (c) analysis of alternative supply options (including pipeline, LNG and CNG); and (d) financial modeling.
- Directed a process review of natural gas expansion projects for a gas utility. The assignment included a review, evaluation and recommendations related to: (a) policies and procedures; (b) process steps and personnel; (c) financial models and analysis; (d) project decisions and schedules; and (e) post-construction review and evaluation.
- Sponsored lead-lag testimony for several electric and gas utilities.

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Sponsor	Date	Docket No.	Subject
Regulatory Commission of Alaska			
ENSTAR Natural Gas Company	06/16	Docket No. U-16-066	Adopted testimony and sponsored Lead/Lag study for a general rate case proceeding.
Arkansas Public Service Commission			
Liberty Utilities (Pine Bluff Water)	10/18	Docket No. 18-027-U	Sponsored testimony supporting the cost of service, rate design and bill impact studies for a general rate case proceeding.
Connecticut Public Utilities Regulatory Authority			
Yankee Gas Company	07/14	Docket No. 13-06-02	Sponsored report and testimony supporting the review and evaluation of gas expansion policies, procedures and analysis.
Illinois Commerce Commission			
Liberty Utilities (Midstates Natural Gas)	07/16	Docket No. 16-0401	Sponsored testimony supporting the cost of service, rate design and bill impact studies for a general rate case proceeding. The testimony includes proposal for new commercial classes and a decoupling mechanism.
Iowa Utilities Board			
Liberty Utilities (Midstates Natural Gas)	07/16	Docket No. RPU-2016-0003	Sponsored testimony supporting the cost of service, rate design and bill impact studies for a general rate case proceeding. The testimony includes proposal for new commercial classes.
Kansas Corporation Commission			
The Empire District Electric Company	12/18	Docket No. 19-EPDE-223-RTS	Sponsored testimony supporting cost of service, rate design, bill impact and lead-lag studies for a general rate case proceeding.
Maine Public Utilities Commission			
Northern Utilities, Inc. d/b/a Unitil Gas Limited	06/15	Case No. 2015-00146	Sponsored testimony supporting the proposed gas expansion program, including a zone area surcharge.
Maryland Public Service Commission			
Sandpiper Energy, a Chesapeake Utilities company	12/15	Case No. 9410	Sponsored testimony supporting the cost of service, rate design and bill impact studies for a general rate case proceeding. The testimony includes proposal for new residential and commercial classes.
Massachusetts Department of Public Utilities			
Boston Gas	03/88	Docket No. DPU 88-67-II	Sponsored testimony supporting the rate reclassification of commercial and industrial customers for a rate design proceeding.
Boston Gas	03/90	DPU 90-55	Sponsored testimony supporting the weather and other cost of service adjustments, rate design and customer bill impact studies for a general rate case proceeding.
Boston Gas	10/93	DPU 92-230	Sponsored testimony describing the Company's position regarding rate treatment of vehicular natural gas investments and expenses.

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Sponsor	Date	Docket No.	Subject
Liberty Utilities (New England Gas Company)	07/16	DPU 16-109	Sponsored the Long-Range Forecast and Supply Plan filing for the five-year forecast period 2016/2017 through 2020/2021.
Liberty Utilities (New England Gas Company)	07/18	DPU 18-68	Sponsored the Long-Range Forecast and Supply Plan filing for the five-year forecast period 2018/2019 through 2022/2023.
Michigan Public Service Commission			
Lansing Board of Water & Light and Michigan State University	4/19	Docket No. U-20322	Sponsored testimony evaluating Consumer Energy's cost of service and rate design proposals.
Midland Cogeneration Ventures, LLC	09/18	Docket No. U-18010	Sponsored testimony evaluating Consumer Energy's cost of service and rate design proposals.
Missouri Public Service Commission			
Liberty Utilities (Midstates Natural Gas)	09/17	Docket No. GR-2018-0013	Sponsored testimony supporting the cost of service, rate design, bill impact and lead-lag studies for a general rate case proceeding. The testimony also included proposals for a revenue decoupling/ weather normalization mechanism as well as tracker accounts for certain O&M expenses and capital costs.
Laclede Gas Company	04/17	Docket No. GR-2017-0215	Sponsored testimony supporting the cost of service, rate design, bill impact and Lead/Lag studies for a general rate case proceeding. The testimony included support for a decoupling mechanism.
Missouri Gas Energy	04/17	Docket No. GR-2017-0216	Sponsored testimony supporting the cost of service, rate design, bill impact and Lead/Lag studies for a general rate case proceeding. The testimony included support for a decoupling mechanism.
New Hampshire Public Utilities Commission			
Liberty Utilities d/b/a Granite State Electric Company	04/16	Docket No. DE 16-383	Adopted testimony and sponsored Lead/Lag study for a general rate case proceeding.
Liberty Utilities (EnergyNorth Natural Gas) Corp. d/b/a Liberty Utilities	11/17	Docket No. DG 17-198	Sponsored testimony supporting a levelized cost analysis for approval of firm supply and transportation agreements.
New Jersey Board of Public Utilities			
Pivotal Utility Holdings, Inc. d/b/a Elizabethtown Gas Company	8/16	GR16090826	Sponsored testimony supporting the Lead/Lag study for a general rate case proceeding.
Elizabethtown Gas Company	4/19	GR19040486	Sponsored testimony supporting the Lead/Lag study for a general rate case proceeding.
Corporation Commission of Oklahoma			
The Empire District Electric Company	03/19	Cause No. PUD 201800133	Sponsored testimony supporting the cost of service, rate design, bill impact and Lead/Lag studies for a general rate case proceeding.

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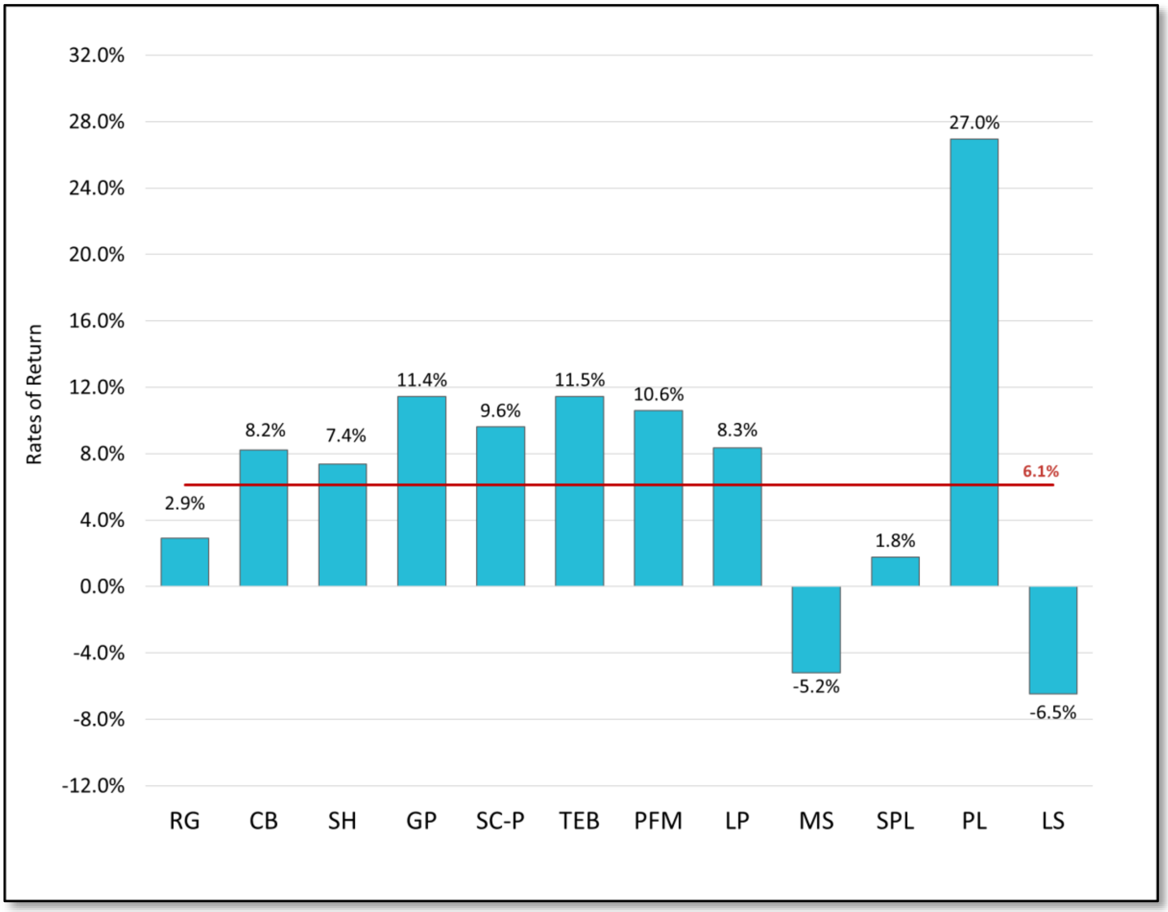
Sponsor	Date	Docket No.	Subject
The Empire District Electric Company	04/17	Cause No. PUD 201600468	Adopted direct testimony and sponsored rebuttal testimony supporting the revenue requirements for a general rate case proceeding. The testimony included proposals for alternative ratemaking mechanisms.
Rhode Island Public Utilities Commission			
Providence Gas Company	01/96	Docket No. 2076	Sponsored testimony supporting the rate reclassification of customers into new rate classes, rate design (including introduction of demand charges), and customer bill impact studies for a rate design proceeding.
Providence Gas Company	11/92	Docket No. 2025	Sponsored testimony supporting the Integrated Resource Plan filing, including a performance-based incentive mechanism.
Providence Gas Company	02/96	Docket No. 2374	Sponsored testimony supporting the rate design, customer bill impact studies and retail access tariffs for largest commercial and industrial customers for a rate design proceeding.
Providence Gas Company	04/97	Docket No. 2552	Sponsored testimony supporting the rate design, customer bill impact studies and retail access tariffs for commercial and industrial customers, including redesign of cost of gas adjustment clause, for a rate design proceeding.
Providence Gas Company	08/01 09/00 08/96	Docket No. 1673	Sponsored testimony supporting the changes in cost of gas adjustment factor related to projected under-recovery of gas costs; Filed testimony and witness for pilot hedging program to mitigate price risks to customers; Filed testimony and witness for changes in cost of gas adjustment factor related to extension of rate plan.
Providence Gas Company	06/97	Docket No. 2581	Sponsored testimony supporting a rate plan that fixed all billing rates for three-year period; included funding for critical infrastructure investments in accelerated replacement of mains and services, digitized records system, and economic development projects.
Providence Gas Company	08/00	Docket No. 2581	Sponsored testimony supporting the extension of a rate plan that began in 1997 and included certain modifications, including a weather normalization clause.
Providence Gas Company	03/00	Docket No. 3100	Sponsored testimony supporting the de-tariff and deregulation of appliance repair service, enabling the Company to have needed pricing flexibility.
Railroad Commission of Texas			
CenterPoint Energy – Texas Gulf Division	11/16	GUD No. 10567	Sponsored testimony supporting the Lead/Lag study for a general rate case proceeding.
Atmos Pipeline – Texas	01/17	GUD No. 10580	Sponsored testimony supporting the Lead/Lag study for a general rate case proceeding.

Sponsor	Date	Docket No.	Subject
Texas Gas Service Company – Rio Grande Valley Service Area	6/17	GUD No. 10656	Sponsored testimony supporting the Lead/Lag study for a general rate case proceeding.
CenterPoint Energy – South Texas Division	11/17	GUD No. 10669	Sponsored testimony supporting the Lead/Lag study for a general rate case proceeding.
Texas Gas Service Company – North Texas Service Area	6/18	GUD No. 10739	Sponsored testimony supporting the Lead/Lag study for a general rate case proceeding.
Texas Gas Service Company – Borger/ Skellytown Service Area	8/18	GUD No. 10766	Sponsored testimony supporting the Lead/Lag study for a general rate case proceeding.
Public Utility Commission of Texas			
CenterPoint Energy Houston Electric, LLC	4/19	Docket No. 49421	Sponsored testimony supporting the Lead/Lag study for a general rate case proceeding.
Vermont Public Utilities Commission			
Vermont Gas Systems	02/11	Docket No. 7712	Sponsored testimony supporting the market evaluation and analysis for a system expansion and reliability regulatory fund.
Vermont Gas Systems	12/12	Docket No. 7970	Sponsored testimony describing the market served by $90 million natural gas expansion project to Addison County, VT. Also described the terms and economic benefits of a special contract with International Paper.

The Empire District Electric Company

Cost of Service Summary



Cost of Service Summary (1/2)

Empire District Electric (MISSOURI) COSS Summary	Total Company	Res Gen RG	Comm CB	Small Heating SH	Gen Pow GP	Prax SC-P
Current Delivery Service Rates						
Rate base	1,457,360,469	770,365,438	124,437,820	29,961,980	223,730,037	8,824,969
Net operating income	89,042,866	22,365,058	10,245,267	2,213,696	25,603,976	849,852
Rate of return	6.11%	2.90%	8.23%	7.39%	11.44%	9.63%
Relative rate of return	100%	48%	135%	121%	187%	158%
Revenues	$ 538,145,269	$ 245,076,376	$ 49,109,480	$ 11,449,205	$ 99,923,339	$ 5,183,196
Test Period Usage (MWh)	4,212,506	1,671,631	316,608	84,989	868,722	69,738
Revenue per MWh	$ 127.75	$ 146.61	$ 155.11	$ 134.71	$ 115.02	$ 74.32
Revenues at Equalized Rates of Return						
Rate of return	7.5%	7.5%	7.5%	7.5%	7.5%	7.5%
Return requirement	109,237,911	57,743,512	9,327,361	2,245,830	16,769,909	661,484
Revenue required	564,661,907	291,512,964	47,901,346	11,490,086	88,326,763	4,935,834
Revenue deficiency	26,516,638	46,436,588	(1,208,133)	40,881	(11,596,575)	(247,362)
Percent increase required	4.93%	18.95%	-2.46%	0.36%	-11.61%	-4.77%
Test Period Usage (MWh)	4,212,506	1,671,631	316,608	84,989	868,722	69,738
Revenue Required per MWh	$ 134	$ 174	$ 151	$ 135	$ 102	$ 71
Revenue Deficiency per MWh	$ 197,820	$ 266,283	$ (7,985)	$ 302	$ (114,056)	$ (3,495)

Cost of Service Summary (2/2)

Empire District Electric (MISSOURI) COSS Summary	Total Elect Bldg TEB	Feed Mill PFM	Large Power LP	Misc. Lts MS	Street Lts SPL	Private Lts PL	Spec Lts LS
Current Delivery Service Rates							
Rate base	96,573,385	220,107	175,702,238	31,846	19,545,740	6,571,636	1,395,274
Net operating income	11,062,724	23,299	14,653,887	(1,659)	345,875	1,771,178	(90,286)
Rate of return	11.46%	10.59%	8.34%	-5.21%	1.77%	26.95%	-6.47%
Relative rate of return	187%	173%	137%	-85%	29%	441%	-106%
Revenues	$ 42,505,741	$ 79,799	$ 76,789,640	$ 16,870	$ 3,510,334	$ 4,355,210	$ 146,079
Test Period Usage (MWh)	358,253	420	805,902	139	22,413	12,922	768
Revenue per MWh	$ 118.65	$ 189.91	$ 95.28	$ 121.46	$ 156.62	$ 337.03	$ 190.12
Revenues at Equalized Rates of Return							
Rate of return	7.5%	7.5%	7.5%	7.5%	7.5%	7.5%	7.5%
Return requirement	7,238,755	16,498	13,169,937	2,387	1,465,071	492,584	104,584
Revenue required	37,486,999	70,899	74,849,688	22,183	5,010,922	2,653,608	400,614
Revenue deficiency	(5,018,743)	(8,900)	(1,939,952)	5,313	1,500,588	(1,701,602)	254,536
Percent increase required	-11.81%	-11.15%	-2.53%	31.50%	42.75%	-39.07%	174.25%
Test Period Usage (MWh)	358,253	420	805,902	139	22,413	12,922	768
Revenue Required per MWh	$ 105	$ 169	$ 93	$ 160	$ 224	$ 205	$ 521
Revenue Deficiency per MWh	$ (47,963)	$ (53)	$ (20,887)	$ 33	$ 6,712	$ (8,286)	$ 488

Summary of Functional Factors

Functional Factor	Functionalization of:	Factor Derivation	Rationale
EXTERNAL FACTORS			
Production Only (PRODUCTION)	**Rate Base:** All Production Plant, and Accumulated Depreciation **Cost of Service:** All Production O&M and Depreciation Expenses	100.0 percent assigned to production Function	Costs and plant accounts only related to procurement and supply of electricity
Transmission Only (TRANSMISSION)	**Rate Base:** All Transmission Plant, and Accumulated Depreciation **Cost of Service:** All Transmission O&M and Depreciation Expenses	100.0 percent assigned to high voltage Transmission Function	Costs and plant accounts only related to transmission facilities

Functional Factor	Functionalization of:	Factor Derivation	Rationale
Primary Distribution Only (PRIMARY)	**Rate Base:** Account 360: Land and Land Rights Account 361: Structures and Improvements Account 362: Station Equipment Primary Plant Accumulated Depreciation **Cost of Service:** Account 582: Station Expenses Account 591: Maintenance of Structures Account 592: Maintenance of Station Equipment Primary Plant Depreciation Expense	100.0 percent assigned to Primary Distribution Function	Costs and plant accounts only related to primary distribution plant

Functional Factor	Functionalization of:	Factor Derivation	Rationale
Secondary Distribution Only (SECONDARY)	**Rate Base:** Account 368: Line Transformers Account 369: Services Account 370: Meters Account 371: Installations on Customers' Premises Account 373: Street Lighting and Signal Systems Account 375: Charging Stations Secondary Plant Accumulated Depreciation Customer Deposits Customer Advances Interest on Customer Deposits **Cost of Service:** Account 585: Street lighting and signal system expenses Account 586: Meter expenses Account 587: Customer installations expenses Account 595: Maintenance of line transformers Account 596: Maintenance of street lighting and Account 597: Maintenance of meters signal systems Secondary Plant Depreciation Expenses	100.0 percent assigned to Secondary Distribution Function	Costs and plant accounts only related to secondary distribution plant

Functional Factor	Functionalization of:	Factor Derivation	Rationale
Customer Service Only (CUSTSERVICE)	**Rate Base:** N/A **Cost of Service:** Customer Account Expenses Customer Service Expenses Sales Expenses	100.0 percent assigned to Customer Service Function	Costs and plant accounts only related to providing customer service e.g., customer account expenses
Poles and Fixtures (POLES)	**Rate Base:** Account 364: Poles, Towers & Fixtures	Company's estimated cost of poles related to primary vs. secondary distribution plant	Cost generally related to Primary and Secondary Plant.
Overhead Conductors & Devices (OHCOND&DEV)	**Rate Base:** Account 365: Overhead Conductors & Devices **Cost of Service:** Account 583: Overhead line expenses Account 593: Maintenance of Overhead Lines	Company's estimated cost of overhead lines related to primary vs. secondary distribution plant	Cost generally related to Primary and Secondary Plant.
Underground Conduits and Devices (UGCOND&DEV)	**Rate Base:** Account 366: Underground Conduit Account 367: Underground Conduit & Device **Cost of Service:** Account 584: Underground line expenses Account 594: Maintenance of underground lines	Company's estimated cost of underground lines related to primary vs. secondary distribution plant	Cost generally related to Primary and Secondary Plant.

Functional Factor	Functionalization of:	Factor Derivation	Rationale
Plant Labor Functional Factor (LABOR)	**Rate Base:** All General Plant Accounts **Cost of Service:** Labor Related A&G Expenses (Accounts 920 through Account 926) Payroll Taxes Federal Unemployment Tax	Composite factor based on the functionalization of Labor-related O&M expenses	Costs generally related to labor costs
INTERNAL FACTORS			
Total Distribution Plant Factor (DISTPT)	**Cost of Service:** Account 588: Miscellaneous distribution expenses Account 589: Rents Account 598: Maintenance of miscellaneous distribution plant	Composite factor based on functionalization of total distribution plant	Costs generally related to all distribution plant accounts
Total General Plant Factor (GENPT)	**Rate Base:** All General Plant Accumulated Depreciation **Cost of Service:** All General Plant Depreciation Expenses	Composite factor based on functionalization of total general plant	Costs related to all general plant accounts

Functional Factor	Functionalization of:	Factor Derivation	Rationale
Total Plant excluding Intangible (TPIS)	**Rate Base:** All Intangible Plant and Accumulated Depreciation Other Rate Base Items (CWIP, Materials and Supplies, Prepayments, ADIT, Regulatory Assets, Regulatory Liabilities, Cash Working Capital, Deferred Income Tax) **Cost of Service:** Intangible Plant Depreciation Expenses Amortization Plant-related A&G expenses (Accounts 924, 925, and 935) Property Taxes Franchise Tax City Tax	Composite factor based on functionalization of all plant accounts excluding intangible plant	Costs generally related to all plant accounts
Distribution Labor Factor (D-LABOR)	**Cost of Service:** Account 580: Operation Supervision & Engineering Account 590: Maintenance Supervision and Engineering	Composite factor based on functionalization of Labor-related distribution expenses	Costs generally related to labor-related distribution expenses
A&G Labor (PTLABOR)	**Cost of Service:** Other A&G Expenses (Accounts 928 through Account 933)	Composite factor based on functionalization of Labor and Plant related A&G Expenses	Costs generally related to labor-related and plant-related A&G expenses

Summary of Classifiers

Classifier	Classification of:	Classifier Derivation	Rationale
EXTERNAL FACTORS			
Customer Factor (CUS)	**Rate Base:** Distribution Plant (Secondary Distribution and Customer Service related only) Customer Deposits Customer Advances **Cost of Service:** Distribution O&M Expenses – Accounts 585-587 (Primary) – Accounts 583-587, 593, 594, 596 (Secondary) – All Accounts (Customer Service) All Customer Account Expenses All Customer Service Expenses All Sales Expenses	Customer-related costs.	Costs related to providing customer-related services.

Classifier	Classification of:	Classifier Derivation	Rationale
Demand Factor (DEM)	**Rate Base:** All Production and Transmission Plant Account 360: Land and Land Rights Account 361: Structures and Improvements Account 362: Station Equipment **Cost of Service:** All Production Expense – except fuel and purchased power expenses All Transmission Expenses Account 582: Station Expenses Account 592: Maintenance of Station Equipment	Demand-related costs.	Costs related to providing demand-related services.
Commodity Factor (COM)	**Cost of Service:** Accounts 501, 547: Fuel Expenses Account 555: On-System Purchase Power Account 556: System Control and Load Dispatching	Commodity-related costs.	Costs related to providing supply-related services.
Poles and Fixtures (Poles)	**Rate Base:** Account 364: Poles, Towers & Fixtures – Primary Distribution only	Poles and Fixtures Classifier based on Minimum-System Study.	Investment in poles and fixtures related to providing customer-related and demand-related services. Methodology to develop classifier consistent with Company’s approach in prior study.

Classifier	Classification of:	Classifier Derivation	Rationale
Overhead Lines (P-LINES)	**Rate Base:** Account 365: Overhead Conductors & Devices – Primary Distribution only **Cost of Service:** Account 583: Overhead line expenses – Primary Distribution only Account 593: Maintenance of Overhead Lines – Primary Distribution only	Overhead Lines Classifier based on Minimum-System Study.	Investment in overhead lines related to providing customer-related and demand-related services. Methodology to develop classifier consistent with Company's approach in prior study.
Underground Conduit (U-LINES)	**Rate Base:** Account 366: Underground Conduit – Primary Distribution only	Underground Lines Classifier based on Minimum-System Study.	Investment in underground conduits related to providing customer-related and demand-related services. Methodology to develop classifier consistent with Company's approach in prior study.
Underground Conductors and Devices (UD-LINES)	**Rate Base:** Account 367: Underground Conductors & Device – Primary Distribution only **Cost of Service:** Account 584: Underground line expenses – Primary Distribution only Account 594: Maintenance of underground lines – Primary Distribution only	Underground Conductors and Devices Classifier based on Minimum-System Study.	Investment in underground conductors and devices related to providing customer-related and demand-related services. Methodology to develop classifier consistent with Company's approach in prior study.
Line Transformers (L-Transformers)	**Rate Base:** Account 368: Line Transformers **Cost of Service:** Account 595: Maintenance of line transformers – Secondary Distribution only	Transformers Classifier based on Minimum-System Study.	Investment in transformers related to providing customer-related and demand-related services. Methodology to develop classifier consistent with Company's approach in prior study.
INTERNAL FACTORS [CALCULATED FOR EACH FUNCTION]			

Classifier	Classification of:	Classifier Derivation	Rationale
Total Plant Factor (TOTPLT)	**Rate Base:** All Intangible Plant All Additions to Utility Plant All Other Rate Base Items – except Cash Working Capital, Customer Deposits, Customer Advances, & Interest on Customer Deposits **Cost of Service:** Plant-related A&G expenses (Accounts 924, 925, & 935) Amortization Property Taxes Franchise Tax City Tax Interest Expenses	Composite classifier based on total gross plant excluding intangible plant.	Items generally consistent with total plant accounts.
Intangible Plant Factor (INTPLT)	**Rate Base:** Intangible Plant Accumulated Depreciation **Cost of Service:** Intangible Plant Depreciation Expense	Composite classifier based on total intangible plant.	Items generally consistent with intangible accounts.
Transmission Plant Factor (TRANSPLT)	**Rate Base:** Transmission Plant Accumulated Depreciation **Cost of Service:** Transmission Plant Depreciation Expense	Composite classifier based on total transmission plant.	Items generally consistent with transmission plant accounts.
Production Plant Factor (PRODPLT)	**Rate Base:** Production Plant Accumulated Depreciation **Cost of Service:** Production Plant Depreciation Expense	Composite classifier based on total production plant.	Items generally consistent with production plant accounts.

Classifier	Classification of:	Classifier Derivation	Rationale
Distribution Plant Factor (DISTPLT)	**Rate Base:** Primary, Secondary, & Customer Service-related Distribution Plant Accumulated Depreciation **Cost of Service:** Primary, Secondary, & Customer Service-related Distribution Plant Depreciation Expense	Composite classifier based on total distribution plant.	Items generally consistent with distribution plant accounts.
General Plant Factor (GENPLT)	**Rate Base:** General Plant Accumulated Depreciation **Cost of Service:** General Plant Depreciation Expense	Composite classifier based on total general plant.	Items generally consistent with general plant accounts.
Plant Accounts 362-375 Factor (ACCT362-375)	**Rate Base:** Account 360: Land and Land Rights Account 361: Structures and Improvements	Composite classifier based on major distribution plant accounts.	Items generally consistent with major distribution plant accounts.
O&M Classifier (O&M)	**Rate Base:** Cash Working Capital	Composite classifier based on total O&M expenses.	Items generally consistent with total O&M expenses.
Labor Classifier (LABOR)	**Rate Base:** All General Plant **Cost of Service:** Administration & General Expense (Accounts 920 through 926) Payroll Taxes Federal Unemployment Tax	Composite classifier based on total labor-related O&M expenses.	Items generally consistent with labor-related expenses.
A&G Labor Classifier (A&GLAB)	**Cost of Service:** Administrative & General Expense (Accounts 929 & 930 through 933)	Composite classifier based on labor-related A&G expenses.	Items generally consistent with labor-related A&G expenses.

Classifier	Classification of:	Classifier Derivation	Rationale
O&M Accounts 582-587 (OPEX582-587)	**Cost of Service:** Account 580: Operation Supervision & Engineering – except Customer Service Account 588: Miscellaneous distribution expenses – except Customer Service Account 589: Rents – except Customer Service	Composite classifier based on major distribution operations expenses.	Items generally consistent with major distribution operations expenses.
O&M Accounts 591-597 (OPEX592-597)	**Cost of Service:** Account 590: Maintenance Supervision and Engineering – except Customer Service Account 591: Maintenance of Structures – except Customer Service Account 598: Maintenance of miscellaneous distribution plant – except Customer Service	Composite classifier based on major distribution maintenance expenses.	Items generally consistent with major distribution maintenance expenses.
O&M Expenses Less A&G (NonAG)	**Cost of Service:** Account 928: Regulatory commission expenses	Composite classifier based on non-A&G O&M expenses.	Items generally consistent with non-A&G O&M expenses.

Summary of Allocators

Allocator	Allocation of:	Allocator Derivation	Rationale
EXTERNAL FACTORS			
Number of Customers (CUSTOMERS)	**Rate Base:** Distribution Plant (Customer-related portion of Primary Distribution only) **Cost of Service:** Major Distribution O&M Expenses (Customer-related portion of Primary Distribution only) Account 902: Meter reading Customer Service Expenses (Accounts 909 & 910)	Allocator is based on the percentage of bills within each rate class.	Costs are generally related to the number of customers. This is consistent with the approach taken in the most recent cost of service study.
Number of Customers (Secondary Voltage) (CUSTOMERS-SEC)	**Rate Base:** Distribution Plant Accounts 364 through 367 (Secondary Distribution-related only) Account 375: Charging Stations (Customer-related only) **Cost of Service:** Distribution Expenses Accounts 583 & 584, 593 & 594 (Customer-related portion of Secondary Distribution only)	Allocator is based on the percentage of bills within each rate class served through secondary distribution system.	Costs are generally related to the number of customers. This is consistent with the approach taken in the most recent cost of service study.

Allocator	Allocation of:	Allocator Derivation	Rationale
Annual Sales (KWH)	**Cost of Service:** Accounts 501, 547: Fuel Expenses Account 555: On-System Purchase Power (Energy & Demand) Account 556: System Control and Load Dispatching Expenses	Allocator is based on annual kWh usage of each rate class.	Costs generally related to kWh sales.
Average & Excess - 12 Month Non-Coincident Peak @ Generation (A&E 12NCP)	**Rate Base:** All Production Plant **Cost of Service:** All Production-related O&M Expenses – except fuel and purchased power expenses	Allocator is based on the Average and Excess 12-month Coincident Peak Allocator.	Production investments and costs are generally driven by customer demands which are represented by two components: 1) average customer demands, and 2) customer demands in excess of average demand. The method varies slightly from the method filed in the Company's most recent rate case.
12 Month Coincident Peak @ Transmission (12 CP Trans)	**Rate Base:** All Transmission Plant **Cost of Service:** All Transmission Expenses	Allocator is based on each customer class' 12-month Coincident Peaks.	Transmission investments and costs are generally related to addressing customers' peak demands through the year. This is consistent with the approach taken in the Company's most recent cost of service study.
Non-Coincident Primary (6 NCP Primary)	**Rate Base:** Distribution Plant (Accounts 362 through 368 – Demand-related portion of 'Primary Distribution') **Cost of Service:** Distribution Expenses (Accounts 582 through 584, 592 through 594 – Demand & Primary Distribution-related only)	Allocator is based on each customer class' non-coincident peak demands during three months of winter (December, January, February) and three months of summer (June, July, August) at primary voltage level.	Distribution investments and costs are generally related to addressing customers' peak demands in the year. The approach varies with the approach taken in the most recent cost of service study, where customer classes' single non-coincident peaks were the basis of distribution cost allocation.

Allocator	Allocation of:	Allocator Derivation	Rationale
Non-Coincident Secondary (6 NCP Secondary)	**Rate Base:** Distribution Plant (Accounts 368 & 375 – Demand & Secondary Distribution-related only) **Cost of Service:** Distribution Expenses (Accounts 593 through 595 – Demand & Secondary Distribution-related only)	Allocator is based on each customer class' non-coincident peak demands during three months of winter (December, January, February) and three months of summer (June, July, August) at secondary voltage level.	Distribution investments and costs are generally related to addressing customers' peak demands in the year. The approach varies with the approach taken in the most recent cost of service study, where customer classes' single non-coincident peaks were the basis of distribution cost allocation.
Transformers Allocation (Line-Transformers)	**Rate Base:** Account 368: Line Transformers – Customer & Secondary Distribution-related only **Cost of Service:** Account 595: Maintenance of line transformers – Customer-related only	Allocator based on number of customers, weighted by a factor representing the number of customers in each customer class served by a single transformer. Weighted factor based on Company's mapping data.	Transformers are installed in proportion to the number of customers that need to be served in the area. This is consistent with the approach taken in the Company's prior cost of service study.
Account 369 Services Allocator (SERVICES)	**Rate Base:** Account 369: Services **Cost of Service:** Account 587: Customer installations expenses	Allocator is based on Company-provided average service costs (including labor, material, and overheads) for each customer class.	Service costs can be reasonably allocated based on average service line installation costs for different types of customers. The services cost data has been updated compared to the Company's prior cost of service study.
Customer Deposits (CustDeposits)	**Rate Base:** Customer Deposits	Allocator is based on percentage of actual customer deposits by each rate class during the test year period.	Costs are directly assigned based on Company data.

Allocator	Allocation of:	Allocator Derivation	Rationale
Account 370 Meters Allocator (METERCOST)	**Rate Base:** Account 370: Meters **Cost of Service:** Account 586: Meter expenses Account 597: Maintenance of meters	Allocator is based on Company-provided average meter costs (including labor, material, and overheads) for each customer class.	Meter costs can be reasonably allocated based on average meter installation costs for different types of customers. The meters' cost data has been updated compared to the Company's prior cost of service study.
Account 903 Collections (ACCT-903)	**Cost of Service:** Customer Account Expense – except Accounts 902 & 904	Allocator is based on a combination of allocators applied on individual GL accounts. Allocators include number of customers, revenues, and uncollectible expenses.	Individual GL accounts can be reasonably allocated based on a combination of allocators. This is consistent with the approach taken in the Company's prior cost of service study.
Account 904 (Uncollectibles)	**Cost of Service:** Account 904: Uncollectible accounts	Allocator is based on the Company's bad debt data for each customer class.	Costs are directly assigned using Company provided actual data. This is generally consistent with the approach taken in the Company's prior cost of service study.
Account 908 Customer Assistance (ACCT-908)	**Cost of Service:** Account 907: Customer Service Supervision Account 908: Customer Assistance	Allocator is based on individual GL account allocations to residential, commercial, and industrial customers.	Individual GL accounts can be reasonably allocated to different customer categories. This is consistent with the approach taken in the Company's prior cost of service study.
Account 912 Allocator (ACCT-912)	**Cost of Service:** Account 912: Demonstration and Selling Expenses	Allocator is based on individual GL account allocations to residential, commercial, and industrial customers.	Individual GL accounts can be reasonably allocated to different customer categories. This is generally consistent with the approach taken in the Company's prior cost of service study.
Installations on Customer Premises (ACCT-371)	**Rate Base:** Account 371: Installation on Customers' Premises	Allocation mostly to Private Lighting customer class.	Costs are generally related private lighting. The allocation methodology has been updated compared to the Company's prior cost of service study.

Allocator	Allocation of:	Allocator Derivation	Rationale
Street Lighting Plant Allocation (ACCT-373)	**Rate Base:** Account 373: Street Lighting & Signal Systems	Allocation 100.0 percent to municipal street lighting customer class	Costs are generally related municipal street lighting. The allocation methodology has been updated compared to the Company's prior cost of service study.
Street Lighting Expenses Allocation (ACCT-595-596)	**Cost of Service:** Account 585: Street lighting and signal system expenses Account 596: Maintenance of street lighting and signal systems	Allocator is based on Company's estimates of street lighting expense allocation to municipal street and private lighting customer classes.	Costs are generally related to serving municipal street and private lighting classes. The allocation methodology has been updated compared to the Company's prior cost of service study.
INTERNAL FACTORS [CALCULATED FOR EACH FUNCTION]			
Total Plant (TOTPLT)	**Rate Base:** All Intangible Plant All Additions to Utility Plant All Other Rate Base Items – except Cash Working Capital, Customer Deposits, and Interest on Customer Deposits **Cost of Service:** Plant-related A&G expenses (Accounts 924, 925, & 935) Amortization Property Taxes Franchise Tax City Tax Interest Synchronization	Allocator is based on total plant allocation.	Costs are generally related to total plant.

Allocator	Allocation of:	Allocator Derivation	Rationale
Intangible Plant (INTPLT)	**Rate Base:** Intangible Plant Accumulated Depreciation **Cost of Service:** Intangible Plant Depreciation Expense	Allocator is based on intangible plant allocation.	Costs are generally related to intangible plant.
Transmission Plant (TRANSPLT)	**Rate Base:** Transmission Plant Accumulated Depreciation **Cost of Service:** Transmission Plant Depreciation Expense	Allocator is based on transmission plant allocation.	Costs are generally related to transmission plant.
Production Plant (PRODPLT)	**Rate Base:** Production Plant Accumulated Depreciation **Cost of Service:** Production Plant Depreciation Expense	Allocator is based on production plant allocation.	Costs are generally related to production plant.
Distribution Plant (DISTPLT)	**Rate Base:** Distribution Plant Accumulated Depreciation **Cost of Service:** Distribution Plant Depreciation Expense	Allocator is based on distribution plant allocation.	Costs are generally related to distribution plant.

Allocator	Allocation of:	Allocator Derivation	Rationale
General Plant (GENPLT)	**Rate Base:** General Plant Accumulated Depreciation **Cost of Service:** General Plant Depreciation Expense	Allocator is based on general plant allocation.	Costs are generally related to general plant.
Distribution Plant Accounts 362-375 (ACCT362-375)	**Rate Base:** Account 360: Land and Land Rights Account 361: Structures and Improvements	Allocator is based on composite allocation of major distribution plant accounts (Account 362 through Account 375)	Costs generally follow major distribution plant accounts.
Labor Allocator (LABOR)	**Rate Base:** All General Plant **Cost of Service:** A&G Expenses (Accounts 920 through 923 & 926) Payroll Taxes, Federal Unemployment Tax	Allocator is based on composite allocation of labor-related production, transmission, distribution, customer service, customer accounts, and sales expenses.	Costs generally follow labor-related O&M expenses.
A&G Labor (A&GLAB)	**Cost of Service:** A&G Expenses (Accounts 929 through 933)	Allocator is based on composite allocation of labor-related A&G expenses.	Costs generally follow labor-related O&M expenses.
Total O&M (O&M)	**Rate Base:** Cash Working Capital	Allocator is based on composite allocation of total O&M expenses.	Costs generally follow total O&M expenses.
O&M Accounts 582-587 (OPEX582-587)	**Cost of Service:** Account 580: Operation Supervision & Engineering Account 588: Miscellaneous distribution expenses Account 589: Rents	Allocator is based on composite allocation of major distribution operations expenses (Account 582 through Account 587)	Costs generally follow major distribution operations expenses.

Allocator	Allocation of:	Allocator Derivation	Rationale
O&M Accounts 591-597 (OPEX592-597)	**Cost of Service:** Account 590: Maintenance Supervision and Engineering Account 591: Maintenance of Structures Account 598: Maintenance of miscellaneous distribution plant	Allocator is based on composite allocation of major distribution maintenance expenses (Account 592 through Account 597)	Costs generally follow major distribution maintenance expenses.
O&M Expenses Less A&G (NonAG_O&M)	**Cost of Service:** Account 928: Regulatory commission expenses	Allocator based on total O&M expenses other than A&G expenses.	Costs generally related to all O&M expenses other than A&G expenses.

The Empire District Electric Company

Summary of Functionalization Factors

Empire District Electric (MISSOURI) Functional Factors	Code	Total	Production	Transmission	Primary Distribution	Secondary Distribution	Customer Service
INTERNAL FUNCTIONAL FACTORS							
Production Only	PRODUCTION	100.0%	100.0%	0.0%	0.0%	0.0%	0.0%
Transmission Only	TRANSMISSION	100.0%	0.0%	100.0%	0.0%	0.0%	0.0%
Primary Distribution Only	PRIMARY	100.0%	0.0%	0.0%	100.0%	0.0%	0.0%
Secondary Distribution Only	SECONDARY	100.0%	0.0%	0.0%	0.0%	100.0%	0.0%
Customer Service Only	CUSTSERVICE	100.0%	0.0%	0.0%	0.0%	0.0%	100.0%
Total Distribution Plant Factor	DISTPT	100.0%	0.0%	0.0%	66.3%	33.7%	0.0%
Total General Plant Factor	GENPT	100.0%	21.4%	3.4%	7.2%	7.1%	61.0%
Total Operating Expenses	OPEXP	100.0%	69.3%	7.0%	6.6%	3.2%	13.9%
Rate Base	RB	100.0%	51.4%	16.3%	21.0%	9.1%	2.1%
Total Plant excl. Intangible	TPIS	100.0%	46.0%	14.1%	24.7%	12.7%	2.5%
EXTERNAL FUNCTIONAL FACTORS							
Poles and Fixtures	POLES	100.0%	0.0%	0.0%	90.8%	9.2%	0.0%
Overhead Conductors & Devices	OHCOND&DEV	100.0%	0.0%	0.0%	92.9%	7.1%	0.0%
Underground Conduits and Devices	UGCOND&DEV	100.0%	0.0%	0.0%	92.2%	7.8%	0.0%
LABOR FUNCTIONAL FACTORS							
Plant Labor Functional Factor	LABOR	100.0%	21.4%	3.4%	7.2%	7.1%	61.0%
Distribution Labor Factor	D-LABOR	100.0%	0.0%	0.0%	50.3%	49.7%	0.0%
A&G Labor	PTLABOR	100.0%	24.1%	4.6%	9.1%	7.7%	54.4%
INTERNAL FUNCTIONAL FACTORS DERIVATION							
Total Plant (All Plant excl. Intangible)		2,585,578,573	1,189,212,460	365,578,481	638,204,498	328,720,882	63,862,253
Total Plant excl. Intangible	TPIS	100.0%	46.0%	14.1%	24.7%	12.7%	2.5%
Total Distribution Plant		952,010,376	-	-	630,706,976	321,303,401	-
Total Distribution Plant Factor	DISTPT	100.0%	0.0%	0.0%	66.3%	33.7%	0.0%
Total General Plant		104,747,883	22,402,915	3,567,711	7,497,522	7,417,482	63,862,253
Total General Plant Factor	GENPT	100.0%	21.4%	3.4%	7.2%	7.1%	61.0%
Plant Labor Functional Factor		71,820,562	15,360,596	2,446,207	5,140,689	5,085,809	43,787,261
Labor Functional Factor	LABOR	100.0%	21.4%	3.4%	7.2%	7.1%	61.0%
Distribution Labor Factor		8,872,429	-	-	4,460,021	4,412,408	-
Distribution Labor Factor	D-LABOR	100.0%	0.0%	0.0%	50.3%	49.7%	0.0%
A&G Labor		54,711,439	13,207,475	2,520,410	4,988,751	4,219,003	29,775,800
A&G Labor	PTLABOR	100.0%	24.1%	4.6%	9.1%	7.7%	54.4%
Total Operating Expenses		334,960,616	232,259,432	23,413,471	21,999,921	10,575,758	46,712,034
Total Operating Expenses	OPEXP	100.0%	69.3%	7.0%	6.6%	3.2%	13.9%

Functionalization of Poles and Fixtures

OH Poles Account 364	%
Primary	90.8%
Secondary	9.2%
Total	100.0%

Functionalization of Overhead Conductors and Devices

OH Conductors & Devices Account 365	Miles		Cost per Mile		Cost	%
Primary	5,591	$	64,151	$	358,665,753	92.9%
Secondary	566	$	48,398	$	27,369,818	7.1%
Total	6,156			$	386,035,571	100.0%

Functionalization of Underground Conductors and Devices

UG Conduits & Devices Account 366-367	Miles		Cost per Mile		Cost	%
Primary	705	$	74,026	$	52,158,695	92.2%
Secondary	151	$	29,380	$	4,431,930	7.8%
Total	855			$	56,590,625	100.0%

The Empire District Electric Company

Summary of Classification Factors

Empire District Electric (MISSOURI) Summary of Classifiers Classifier Description	Classifier Code	Total	- Demand	- Customer	- Commodity
External Classifiers					
Common					
Customer Factor	CUS	100.0%	0.0%	100.0%	0.0%
Demand Factor	DEM	100.0%	100.0%	0.0%	0.0%
Commodity Factor	COM	100.0%	0.0%	0.0%	100.0%
Poles and Fixtures	Poles	100.0%	46.9%	53.1%	0.0%
Overhead Lines	P-LINES	100.0%	87.2%	12.8%	0.0%
Underground Conduit	U-LINES	100.0%	0.0%	100.0%	0.0%
Underground Conductors and Devices	UD-LINES	100.0%	55.4%	44.6%	0.0%
Line Transformers	L-Transformers	100.0%	57.0%	43.0%	0.0%

Classification of Poles and Fixtures

Poles FERC Account 364		Current Cost	Indexed Costs Qty		Total Cost
Pole & Fixtures	$	751.14	211,686	$	159,005,822
Anchors	$	265.41	75,773	$	20,110,912
Guys	$	226.76	92,361	$	20,943,780
Total			211,686	$	200,060,514
Per Pole Cost for Minimum Size System				$	945
Per Pole Cost for Minimum Size System (Primary only)				$	858
Per Pole Cost for Total System				$	1,615
Minimum System Study: Customer Portion					53.1%

Classification of Overhead Conductors and Devices

OH Conductors FERC Account 365	Current Costs	Indexed Costs Qty	Total Cost
Circuit Miles	$ 11,301	6,185	$ 69,898,861
Per Mile Cost for Minimum Size System			$ 11,301
Per Mile Cost for Minimum Size System (Primary)			$ 10,263
Per Mile for Total System			$ 80,392
Minimum System Study: Customer Portion			**12.8%**

Classification of Underground Conductors and Devices

UG Conductors		Indexed Costs		
FERC Account 366	Current Costs	Qty		Total Cost
Per Mile Cost for Minimum Size System			$	154,695
Per Mile for Total System			$	123,598
Minimum System Study: Customer Portion				100.0%

Classification of Underground Conductors and Devices

UG Conductors FERC Account 367		Indexed Costs Current Costs	Qty		Total Cost
Per Circuit Mile	$	70,642	798	$	56,372,112
Per Mile Cost for Minimum Size System				$	70,642
Per Mile for Total System				$	158,385
Minimum System Study: Customer Portion					**44.6%**

Classification of Transformers

Transformers FERC Account 368	Current Costs	Indexed Costs Qty	Total Cost
Minimum Size Transformer	$ 1,484	101,345	$ 150,370,257
Per Unit Cost for Minimum Size System			$ 1,483.75
Per Unit Cost for Total System			$ 3,451.20
Minimum System Study: Customer Portion			43.0%

The Empire District Electric Company

Summary of Allocation Factors

Empire District Electric (MISSOURI) Summary of Allocators	Description	Total Company	Res Gen RG	Comm CB	Small Heating SH	Gen Pow GP	Prax SC-P	Total Elect Bldg TEB	Feed Mill PFM	Large Power LP	Misc. Lts MS	Street Lts SPL	Private Lts PL	Spec Lts LS
External Allocators														
External Allocators														
CUSTOMERS	Number of Customers	100.00%	84.35%	11.65%	1.95%	1.16%	0.00%	0.61%	0.01%	0.03%	0.00%	0.00%	0.16%	0.08%
CUSTOMERS-SEC	Number of Customers (Secondary Voltag	100.00%	84.39%	11.65%	1.95%	1.13%	0.00%	0.61%	0.01%	0.01%	0.00%	0.00%	0.16%	0.08%
KWH	Annual Sales	100.00%	39.68%	7.52%	2.02%	20.62%	1.66%	8.50%	0.01%	19.13%	0.00%	0.53%	0.31%	0.02%
REV	Revenues	100.00%	45.54%	9.13%	2.13%	18.57%	0.96%	7.90%	0.01%	14.27%	0.00%	0.65%	0.81%	0.03%
A&E 12NCP	12 Month Non-Coincident Peak @ Gener	100.00%	47.51%	7.97%	2.05%	18.13%	0.90%	7.63%	0.02%	14.74%	0.00%	0.55%	0.42%	0.09%
12 CP Trans	12 Month Coincident Peak @ Transmissi	100.00%	49.58%	7.89%	2.16%	17.40%	0.87%	7.94%	0.01%	14.14%	0.00%	0.00%	0.00%	0.00%
6 NCP Primary	Non-Coincident Primary	100.00%	49.87%	8.07%	2.14%	17.66%	0.00%	7.49%	0.02%	13.65%	0.00%	0.55%	0.43%	0.13%
6 NCP Secondary	Non-Coincident Secondary	100.00%	58.14%	9.41%	2.49%	18.25%	0.00%	8.73%	0.02%	1.67%	0.00%	0.64%	0.50%	0.15%
Line-Transformers	Transformers Allocation	100.00%	75.89%	17.43%	2.59%	2.54%	0.00%	1.32%	0.01%	0.04%	0.00%	0.00%	0.00%	0.18%
SERVICES	Account 369 Services Allocator	100.00%	82.81%	12.64%	2.12%	1.58%	0.00%	0.78%	0.01%	0.00%	0.00%	0.00%	0.00%	0.08%
CustDeposits	Customer Deposits	100.00%	52.12%	13.20%	4.09%	21.41%	0.00%	8.83%	0.00%	0.00%	0.00%	0.00%	0.35%	0.00%
DepInterest	Interest on Customer Deposits	100.00%	47.29%	19.21%	5.90%	15.85%	0.00%	11.22%	0.02%	0.15%	0.00%	0.00%	0.35%	0.01%
METERCOST	Account 370 Meters Allocator	100.00%	80.11%	13.03%	2.33%	2.79%	0.03%	1.51%	0.02%	0.07%	0.00%	0.00%	0.00%	0.11%
ACCT-903	Account 903 Collections	100.00%	83.98%	10.79%	1.84%	1.75%	0.03%	0.89%	0.01%	0.52%	0.00%	0.02%	0.15%	0.03%
Uncollectibles	Account 904 Uncollectibles	100.00%	90.96%	2.20%	0.54%	3.19%	0.00%	1.87%	0.00%	0.53%	0.00%	0.00%	0.71%	0.00%
ACCT-908	Account 908 Customer Assistance	100.00%	76.31%	12.03%	2.01%	1.19%	0.18%	0.63%	0.01%	7.38%	0.00%	0.00%	0.17%	0.08%
ACCT-912	Account 912 Allocator	100.00%	45.99%	8.89%	2.03%	16.68%	0.86%	7.11%	0.01%	12.72%	1.31%	3.64%	0.73%	0.03%
ACCT-371	Installations on Customer Premises	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	93.69%	6.31%
ACCT-373	Street Lighting Plant Allocation	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%	0.00%	0.00%
ACCT-595-596	Street Lighting Expenses Allocation	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	68.00%	32.00%	0.00%

The Empire District Electric Company

Average and Excess Allocator

Average and Excess (12 NCP)						
Rate Class	Peak Demand 12 NCP (MW)	Average Demand (MW)	Excess Demand (MW)	Average Demand (%)	Excess Demand (%)	Total Allocator (%)
RG-Residential	502,707	204,996	297,710	39.90%	56.79%	47.51%
CB-Commercial	83,218	38,826	44,391	7.56%	8.47%	7.97%
SH-Small Heating	21,343	10,422	10,921	2.03%	2.08%	2.05%
GP-General Power	184,960	106,226	78,734	20.67%	15.02%	18.13%
SC-P PRAXAIR Transmission	8,421	8,210	211	1.60%	0.04%	0.90%
TEB-Total Electric Bldg	78,027	43,933	34,094	8.55%	6.50%	7.63%
PFM-Feed Mill/Grain Elev	195	52	143	0.01%	0.03%	0.02%
LP-Large Power	147,847	96,700	51,147	18.82%	9.76%	14.74%
MS-Miscellaneous	17	17	0	0.00%	0.00%	0.00%
SPL-Municipal St Lighting	5,748	2,749	3,000	0.53%	0.57%	0.55%
PL-Private Lighting	4,488	1,585	2,904	0.31%	0.55%	0.42%
LS-Special Lighting	1,077	94	983	0.02%	0.19%	0.09%
Total	1,038,048	513,810	524,238	100.00%	100.00%	100.00%

The Empire District Electric Company

Meters Cost Allocator

Meter Study Rate Class	Number Of Meters	Current Cost per Meter		Current Total Cost	Allocator %
RG-Residential	130,887	202	$	26,491,831	80.11%
CB-Commercial	18,072	238		4,307,978	13.03%
SH-Small Heating	3,028	255		771,473	2.33%
GP-General Power	1,793	515		924,280	2.79%
SC-P Praxxair Transmission	1	11,441		11,441	0.03%
TEB-Total Electric Bldg	946	528		499,152	1.51%
PFM-Feed Mill/Grain Elev	10	510		5,103	0.02%
LP-Large Power	40	545		21,739	0.07%
MS-Miscellaneous	3	202		606	0.00%
SPL - Municipal Street Lighting	7	0		-	0.00%
PL- Private Lighting	252	0		-	0.00%
LS-Special Lighting	126	286		35,932	0.11%
Total	155,165		$	33,069,535	100.00%

Services Cost Allocator

Services Study Rate Class	Number Of Services	Current Cost per Service		Current Total Cost	Allocator %
RG-Residential	130,887	1,242	$	162,542,073	82.81%
CB-Commercial	18,072	1,373		24,806,090	12.64%
SH-Small Heating	3,028	1,373		4,156,310	2.12%
GP-General Power	1,793	1,724		3,091,837	1.58%
SC-P Praxxair Transmission	1	0		-	0.00%
TEB-Total Electric Bldg	946	1,612		1,524,989	0.78%
PFM-Feed Mill/Grain Elev	10	1,724		17,244	0.01%
LP-Large Power	40	0		-	0.00%
MS-Miscellaneous	3	1,205		3,615	0.00%
SPL - Municipal Street Lighting	7	0		-	0.00%
PL- Private Lighting	252	0		-	0.00%
LS-Special Lighting	126	1,205		151,633	0.08%
Total	155,165		$	196,293,792	100.00%

The Empire District Electric Company

Revenue Targets

Empire District Electric (MISSOURI) Target Revenues	Total Company	Res Gen RG	Comm CB	Small Heating SH	Gen Pow GP	Prax SC-P	Total Elect Bldg TEB	Feed Mill PFM	Large Power LP	Misc. Service MS	Street Lts SPL	Private Lts PL	Spec Lts LS
Target Revenues													
Class Revenues at EROR	564,661,907	291,512,964	47,901,346	11,490,086	88,326,763	4,935,834	37,486,999	70,899	74,849,688	22,183	5,010,922	2,653,608	400,614
Current Class Revenues	538,145,269	245,076,376	49,109,480	11,449,205	99,923,339	5,183,196	42,505,741	79,799	76,789,640	16,870	3,510,334	4,355,210	146,079
Difference ($)	26,516,638	46,436,588	(1,208,133)	40,881	(11,596,575)	(247,362)	(5,018,743)	(8,900)	(1,939,952)	5,313	1,500,588	(1,701,602)	254,536
Difference (%)	4.93%	18.95%	-2.46%	0.36%	-11.61%	-4.77%	-11.81%	-11.15%	-2.53%	31.50%	42.75%	-39.07%	174.25%
Target Revenues	564,661,907	259,168,268	51,668,554	12,045,819	103,420,656	5,453,290	43,993,442	82,592	80,437,148	17,840	3,712,178	4,507,643	154,478
Current Revenues	538,145,269	245,076,376	49,109,480	11,449,205	99,923,339	5,183,196	42,505,741	79,799	76,789,640	16,870	3,510,334	4,355,210	146,079
$ Difference	26,516,638	14,091,892	2,559,074	596,613	3,497,317	270,094	1,487,701	2,793	3,647,508	970	201,844	152,432	8,400
% Difference	4.93%	5.75%	5.21%	5.21%	3.50%	5.21%	3.50%	3.50%	4.75%	5.75%	5.75%	3.50%	5.75%
Customers	155,165	130,887	18,072	3,028	1,793	1	946	10	40	3	7	252	126
Usage (MWh)	4,212,506	1,671,631	316,608	84,989	868,722	69,738	358,253	420	805,902	139	22,413	12,922	768
Target Increase ($/ Customer/ Mo.)		$ 8.97	$ 11.80	$ 16.42	$ 162.54	$ 22,507.85	$ 131.03	$ 23.27	$ 7,614.84	$ 26.94	$ 2,402.91	$ 50.49	$ 5.56
Target Increase ($ per MWh)		$ 8.43	$ 8.08	$ 7.02	$ 4.03	$ 3.87	$ 4.15	$ 6.65	$ 4.53	$ 6.98	$ 9.01	$ 11.80	$ 10.93

Target Revenues	Total Company	Res Gen RG	Comm CB	Small Heating SH	Gen Pow GP	Prax SC-P	Total Elect Bldg TEB	Feed Mill PFM	Large Power LP	Misc. Service MS	Street Lts SPL	Private Lts PL	Spec Lts LS
Step #1 increase (GP, TEB, PFM & PL)	3.50%												
Step #2 increase (LP)	4.75%	2.3%	1.13%	4.63%									
Step #3 Increase (RG, MS, SPL & LS)	5.75%	1.17											
Step #1 increase (GP, TEB, PFM & PL)	152,004,332				103,420,656		43,993,442	82,592				4,507,643	
Step #2 increase (LP)	80,437,148								80,437,148				
Step #3 Increase (RG, MS, SPL & LS)	263,052,764	259,168,268								17,840	3,712,178		154,478
Step #4: Allocate Remainder (CB, SH, SC-P)	69,167,663		51,668,554	12,045,819		5,453,290							
Proposed Revenue Targets	564,661,907	259,168,268	51,668,554	12,045,819	103,420,656	5,453,290	43,993,442	82,592	80,437,148	17,840	3,712,178	4,507,643	154,478

The Empire District Electric Company

Revenue Targets

Target Revenues From Base Rates	Total Company	Res Gen RG	Comm CB	Small Heating SH	Gen Pow GP	Prax SC-P	Total Elect Bldg TEB	Feed Mill PFM	Large Power LP	Misc. Service MS	Street Lts SPL	Private Lts PL	Spec Lts LS
Target Revenues													
Total Target Revenues	564,661,907	259,168,268	51,668,554	12,045,819	103,420,656	5,453,290	43,993,442	82,592	80,437,148	17,840	3,712,178	4,507,643	154,478
less:													
Resale - SPP Integrated Market	62,928,655	24,971,714	4,729,653	1,269,612	12,977,434	1,041,789	5,351,774	6,277	12,038,987	2,075	334,820	193,042	11,478
Adjustments	4,885,434	735,991	246,604	63,743	837,981	1,628	280,226	313	1,771,190	5	940,479	7,157	116
Total Other Revenues	10,258,712	4,790,192	960,695	221,503	1,878,091	90,445	806,602	1,613	1,366,752	318	49,273	90,322	2,906
Target Revenues from Base Rates	486,589,107	228,670,371	45,731,602	10,490,961	87,727,149	4,319,429	37,554,840	74,388	65,260,219	15,441	2,387,607	4,217,121	139,978
	(17,837,021.58)												
Current Revenues													
Total Current Revenues	538,145,269	245,076,376	49,109,480	11,449,205	99,923,339	5,183,196	42,505,741	79,799	76,789,640	16,870	3,510,334	4,355,210	146,079
less:													
Resale - SPP Integrated Market	62,928,655	24,971,714	4,729,653	1,269,612	12,977,434	1,041,789	5,351,774	6,277	12,038,987	2,075	334,820	193,042	11,478
Adjustments	(1,223,135)	(2,201,009)	(295,226)	(81,641)	(279,276)	(54,570)	(236,559)	(908)	1,066,261	(117)	902,925	(41,827)	(1,188)
Total Other Revenues	(1,469,741)	(848,849)	(79,619)	(57,634)	(267,043)	(17,457)	(185,625)	(732)	13,288	84	(22,830)	(3,727)	403
Current Revenues from Base Rates	477,909,490	223,154,520	44,754,672	10,318,869	87,492,224	4,213,435	37,576,151	75,162	63,671,103	14,828	2,295,418	4,207,722	135,386

Rate Design: Residential General

Empire District Electric (MISSOURI)
Residential General Rate Design

Base Revenues	Base Rates	Tax and FAC	Adjusted
Target Base Rates	228,670,371		228,670,371
Current Base Rates	223,154,520	(7,081,029)	216,073,491
$ Difference	5,515,852		12,596,881
% Difference	2.5%		5.8%

	Winter	Summer	
Annual Usage - First Block	509,232,839	262,440,517	600
Annual Usage - Second Block	602,353,968	297,603,724	
Annual Usage - Third Block	-	-	
Number of Bills	1,570,644		
Average Annual Use (kWh)	12,772		

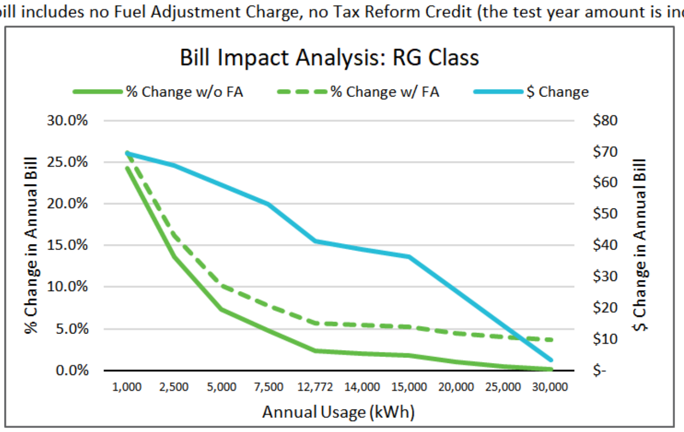
Residential General Rate Design		Rate	Units		Revenues
Proposed Rates					
Customer Charge	$	19.00	1,570,644	$	29,842,236
1st Block kWh - Winter	$	0.12754	509,232,839		64,945,505
2nd Block kWh - Winter	$	0.10369	602,353,968		62,456,843
1st Block kWh - Summer	$	0.12754	262,440,517		33,470,607
2nd Block kWh - Summer	$	0.12754	297,603,724		37,955,180
Revenue at Proposed Rates	$	-		$	228,670,371
Current Rates					
Customer Charge	$	13.00	1,570,644	$	20,418,372
1st Block kWh - Winter	$	0.13006	509,232,839		66,230,823
2nd Block kWh - Winter	$	0.10574	602,353,968		63,692,909
1st Block kWh - Summer	$	0.13006	262,440,517		34,133,014
2nd Block kWh - Summer	$	0.13006	297,603,724		38,706,340
Revenue at Current Rates				$	223,181,457

Bill Impact: Residential General

Bill Impact Analysis - RG Rate			Base Rate Comparison				Annual Bill Comparison			
Annual Use	Cumulative Bills	Cumulative Use	Proposed Base Rates	Current Base Rates	Difference ($)	Difference (%)	Proposed Annual Bill	Current Annual Bill	Difference ($)	Difference (%)
1,000	1.6%	0.1%	$ 356	$ 286	$ 69	24.3%	$ 356	$ 282	$ 74	26.1%
2,500	3.5%	0.3%	547	481	66	13.7%	548	471	76	16.2%
5,000	8.8%	1.7%	866	806	59	7.4%	868	787	81	10.2%
7,500	19.4%	6.4%	1,172	1,119	53	4.8%	1,175	1,090	85	7.8%
12,772	48.4%	26.5%	1,772	1,731	41	2.4%	1,777	1,682	95.54	5.7%
14,000	54.7%	32.2%	1,910	1,871	39	2.1%	1,915	1,817	98	5.4%
15,000	59.5%	37.0%	2,022	1,985	37	1.8%	2,028	1,927	100	5.2%
20,000	78.1%	59.1%	2,581	2,556	25	1.0%	2,589	2,479	110	4.4%
25,000	89.5%	76.4%	3,141	3,127	14	0.5%	3,151	3,031	120	4.0%
30,000	95.1%	86.9%	3,701	3,698	3	0.1%	3,713	3,582	130	3.6%

The current annual bill includes a Tax Reform Credit of $0.00516 per kWh; Fuel Adjustment Charge of $0.00092; and EECR of $0.00039

The proposed annual bill includes no Fuel Adjustment Charge, no Tax Reform Credit (the test year amount is included in base rates); and EECR of $0.00039



Rate Design Alternative: Residential General

Empire District Electric (MISSOURI)
Residential General Rate Design

Base Revenues	Base Rates	Tax and FAC	Adjusted
Target Base Rates	228,670,371		228,670,371
Current Base Rates	223,154,520	(7,081,029)	216,073,491
$ Difference	5,515,852		12,596,881
% Difference	2.5%		5.8%

	Winter	Summer	
Annual Usage - First Block	509,232,839	262,440,517	600
Annual Usage - Second Block	602,353,968	297,603,724	
Annual Usage - Third Block	-	-	
Number of Bills	1,570,644		
Average Annual Use (kWh)	12,772		

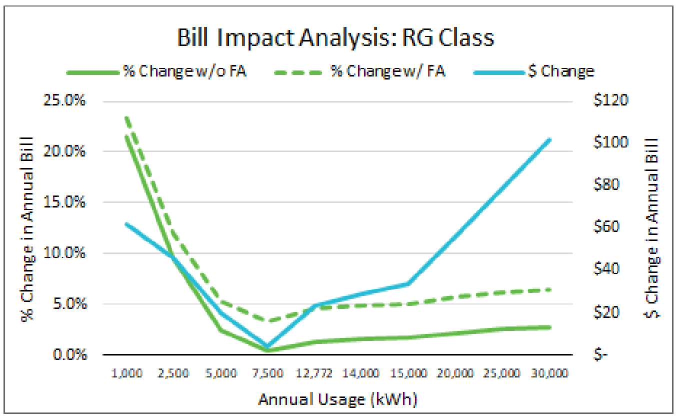
Residential General Rate Design	Rate	Units	Revenues
Proposed Rates			
Customer Charge	$ 19.00	1,570,644	$ 29,842,236
1st Block kWh - Winter	$ 0.12119	509,232,839	61,715,648
2nd Block kWh - Winter	$ 0.10905	602,353,968	65,686,700
1st Block kWh - Summer	$ 0.11680	262,440,517	30,654,077
2nd Block kWh - Summer	$ 0.13700	297,603,724	40,771,710
Revenue at Proposed Rates			$ 228,670,371
Current Rates			
Customer Charge	$ 13.00	1,570,644	$ 20,418,372
1st Block kWh - Winter	$ 0.13006	509,232,839	66,230,823
2nd Block kWh - Winter	$ 0.10574	602,353,968	63,692,909
1st Block kWh - Summer	$ 0.13006	262,440,517	34,133,014
2nd Block kWh - Summer	$ 0.13006	297,603,724	38,706,340
Revenue at Current Rates			$ 223,181,457

Bill Impact Alternative: Residential General

Bill Impact Analysis - RG Rate			Base Rate Comparison				Annual Bill Comparison			
Annual Use	Cumulative Bills	Cumulative Use	Proposed Base Rates	Current Base Rates	Difference ($)	Difference (%)	Proposed Annual Bill	Current Annual Bill	Difference ($)	Difference (%)
1,000	1.6%	0.1%	$ 348	$ 286	$ 62	21.5%	$ 348	$ 282	$ 66	23.3%
2,500	3.5%	0.3%	527	481	46	9.6%	528	471	57	12.0%
5,000	8.8%	1.7%	826	806	20	2.5%	828	787	41	5.2%
7,500	19.4%	6.4%	1,123	1,119	4	0.4%	1,126	1,090	36	3.3%
12,772	48.4%	26.5%	1,754	1,731	23	1.4%	1,759	1,682	77.52	4.6%
14,000	54.7%	32.2%	1,900	1,871	29	1.6%	1,906	1,817	88	4.9%
15,000	59.5%	37.0%	2,019	1,985	34	1.7%	2,025	1,927	97	5.0%
20,000	78.1%	59.1%	2,612	2,556	56	2.2%	2,620	2,479	141	5.7%
25,000	89.5%	76.4%	3,206	3,127	79	2.5%	3,216	3,031	185	6.1%
30,000	95.1%	86.9%	3,800	3,698	102	2.8%	3,812	3,582	229	6.4%

The current annual bill includes a Tax Reform Credit of $0.00516 per kWh; Fuel Adjustment Charge of $0.00092; and EECR of $0.00039

The proposed annual bill includes no Fuel Adjustment Charge, no Tax Reform Credit (the test year amount is included in base rates); and EECR of $0.00039



Rate Design: Commercial Class

Empire District Electric (MISSOURI)
Commercial Rate Design

Base Revenues		Tax and FAC	Adjusted
Target Base Rates	45,731,602		45,731,602
Current Base Rates	44,754,672	(1,296,825)	43,457,847
$ Difference	976,930		2,273,755
% Difference	2.2%		5.2%

	Winter	Summer	
Annual Usage - First Block	60,331,972	28,203,917	700
Annual Usage - Second Block	139,779,617	88,292,119	
Annual Usage - Third Block	-	-	
Number of Bills	216,864		
Average Annual Use (kWh)	17,519		

Commercial Rate Design	Rate	Units	Revenues
Proposed Rates			
Customer Charge	$ 25.00	216,864	$ 5,421,600
1st Block kWh - Winter	$ 0.13326	60,331,972	8,039,888
2nd Block kWh - Winter	$ 0.11980	139,779,617	16,745,758
1st Block kWh - Summer	$ 0.13326	28,203,917	3,758,477
2nd Block kWh - Summer	$ 0.13326	88,292,119	11,765,879
Revenue at Proposed Rates			$ 45,731,602
Current Rates			
Customer Charge	$ 22.69	216,864	$ 4,920,644
1st Block kWh - Winter	$0.13168	60,331,972	7,944,514
2nd Block kWh - Winter	$0.11838	139,779,617	16,547,111
1st Block kWh - Summer	$0.13168	28,203,917	3,713,892
2nd Block kWh - Summer	$0.13168	88,292,119	11,626,306
Revenue at Current Rates			$ 44,752,467

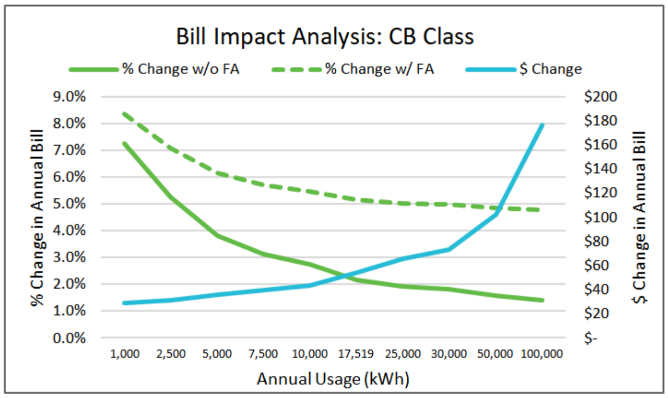
Bill Impact: Commercial Class

Bill Impact Analysis - CB Rate

			Base Rate Comparison				Annual Bill Comparison			
Annual Use	Cumulative Bills	Cumulative Use	Proposed Base Rates	Current Base Rates	Difference ($)	Difference (%)	Proposed Annual Bill	Current Annual Bill	Difference ($)	Difference (%)
1,000	8.0%	0.2%	$ 433	$ 404	$ 29	7.3%	$ 433	$ 400	$ 33	8.3%
2,500	17.7%	0.9%	633	601	32	5.3%	634	592	42	7.1%
5,000	29.1%	2.8%	966	931	36	3.8%	968	912	56	6.2%
7,500	38.4%	5.3%	1,299	1,260	40	3.1%	1,302	1,232	70	5.7%
10,000	45.8%	8.1%	1,624	1,580	43	2.7%	1,628	1,543	84	5.5%
17,519	61.9%	17.8%	2,562	2,508	55	2.2%	2,569	2,443	126	5.2%
25,000	71.5%	26.7%	3,496	3,431	66	1.9%	3,506	3,338	168	5.0%
30,000	76.3%	32.5%	4,120	4,047	73	1.8%	4,132	3,936	196	5.0%
50,000	87.1%	50.9%	6,617	6,514	103	1.6%	6,637	6,329	307	4.9%
100,000	97.0%	81.6%	12,859	12,682	177	1.4%	12,898	12,312	586	4.8%

The current annual bill includes a Tax Reform Credit of $0.00502 per kWh; Fuel Adjustment Charge of $0.00092; and EECR of $0.00039

The proposed annual bill includes no Fuel Adjustment Charge, no Tax Reform Credit (the test year amount is included in base rates); and EECR of $0.00039



Rate Design: Small Heating

Empire District Electric (MISSOURI)
Small Heating

Base Revenues		Tax and FAC	Adjusted
Target Base Rates	10,490,961		10,490,961
Current Base Rates	10,318,869	(325,168)	9,993,701
$ Difference	172,092		497,260
% Difference	1.7%		5.0%

	Winter	Summer	
Annual Usage - First Block	12,906,495	6,095,171	700
Annual Usage - Second Block	44,284,768	21,702,609	
Annual Usage - Third Block	-	-	
Number of Bills	36,336		
Average Annual Use (kWh)	28,068		

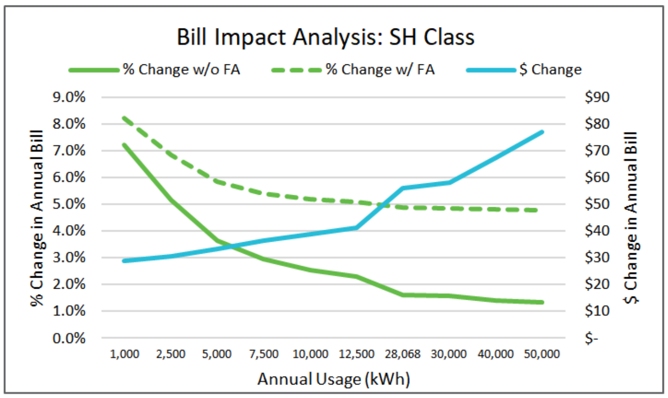
Small Heating		Rate	Units		Revenues
Proposed Rates					
Customer Charge	$	25.00	36,336	$	908,400
1st Block kWh - Winter	$	0.12987	12,906,495		1,676,137
2nd Block kWh - Winter	$	0.09702	44,284,768		4,296,392
1st Block kWh - Summer	$	0.12987	6,095,171		791,566
2nd Block kWh - Summer	$	0.12987	21,702,609		2,818,467
Revenue at Proposed Rates				$	10,490,961
Current Rates					
Customer Charge	$	22.69	36,336	$	824,464
1st Block kWh - Winter		$0.12872	12,906,495		1,661,324
2nd Block kWh - Winter		$0.09616	44,284,768		4,258,423
1st Block kWh - Summer		$0.12872	6,095,171		784,570
2nd Block kWh - Summer		$0.12872	21,702,609		2,793,560
Revenue at Current Rates				$	10,322,342

Bill Impact: Small Heating

Bill Impact Analysis - SH Rate										
			Base Rate Comparison				Annual Bill Comparison			
Annual Use	Cumulative Bills	Cumulative Use	Proposed Base Rates	Current Base Rates	Difference ($)	Difference (%)	Proposed Annual Bill	Current Annual Bill	Difference ($)	Difference (%)
1,000	3.5%	0.1%	$ 430	$ 401	$ 29	7.2%	$ 430	$ 397	$ 33	8.2%
2,500	7.7%	0.3%	625	594	31	5.1%	626	586	40	6.9%
5,000	13.7%	1.0%	949	916	33	3.7%	951	899	53	5.9%
7,500	19.6%	2.1%	1,269	1,233	36	2.9%	1,272	1,207	65	5.4%
10,000	26.3%	4.0%	1,560	1,521	39	2.6%	1,564	1,487	77	5.2%
12,500	33.1%	6.3%	1,833	1,791	41	2.3%	1,838	1,748	89	5.1%
28,068	59.9%	22.5%	3,512	3,456	56	1.6%	3,523	3,360	163	4.9%
30,000	63.0%	25.3%	3,721	3,663	58	1.6%	3,732	3,560	173	4.9%
40,000	72.3%	35.3%	4,799	4,732	67	1.4%	4,815	4,595	221	4.8%
50,000	79.2%	45.0%	5,878	5,801	77	1.3%	5,898	5,629	268	4.8%

The current annual bill includes a Tax Reform Credit of $0.00475 per kWh; Fuel Adjustment Charge of $0.00092; and EECR of $0.00039

The proposed annual bill includes no Fuel Adjustment Charge, no Tax Reform Credit (the test year amount is included in base rates); and EECR of $0.00039



Rate Design: General Power

Empire District Electric (MISSOURI)
General Power Rate Design

Base Revenues		Tax and FAC	Adjusted
Target Base Rates	87,727,149		87,727,149
Current Base Rates	87,492,224	(2,411,573)	85,080,651
$ Difference	234,926		2,646,498
% Difference	0.3%		3.1%

	Winter	Summer
First 150 Hours kWh	234,241,155	132,263,471
Next 200 Hours kWh	219,174,878	132,739,339
All Additional kWh	86,861,527	63,441,837
Facility Demand kW	2,215,774	1,099,435
Billed Demand kW	1,642,244	914,361
Number of Bills	21,516	
Average Annual Use	484,508	

General Power Rate Design	Rate	Units	Revenues
Proposed Rates			
Customer Charge	$ 80.00	21,516	$ 1,721,280
First 150 Hours - Winter	$ 0.07799	234,241,155	18,268,468
Next 200 Hours - Winter	$ 0.06420	219,174,878	14,071,027
All Additional - Winter	$ 0.06368	86,861,527	5,531,342
First 150 Hours - Summer	$ 0.09024	132,263,471	11,935,456
Next 200 Hours - Summer	$ 0.07084	132,739,339	9,403,255
All Additional - Summer	$ 0.06398	63,441,837	4,059,009
Facility Demand kW - Winter	$ 2.070	2,215,774	4,587,723
Billed Demand kW - Winter	$5.71	1,642,244	9,377,211
Facility Demand kW - Summer	$ 2.070	1,099,435	2,276,361
Billed Demand kW - Summer	$7.33	914,361	6,702,270
Other Adjustments			(206,251)
Revenue at Proposed Rates			$ 87,727,149
Current Rates			
Customer Charge	$ 69.49	21,516	$ 1,495,147
First 150 Hours - Winter	$0.07799	234,241,155	18,268,468
Next 200 Hours - Winter	$0.06420	219,174,878	14,071,027
All Additional - Winter	$0.06368	86,861,527	5,531,342
First 150 Hours - Summer	$0.09024	132,263,471	11,935,456
Next 200 Hours - Summer	$0.07084	132,739,339	9,403,255
All Additional - Summer	$0.06398	63,441,837	4,059,009
Facility Demand kW - Winter	$2.07	2,215,774	4,586,652
Billed Demand kW - Winter	$5.71	1,642,244	9,377,211
Facility Demand kW - Summer	$2.07	1,099,435	2,275,830
Billed Demand kW - Summer	$7.33	914,361	6,702,270
Other Adjustments			(206,251)
Revenue at Current Rates			$ 87,499,415

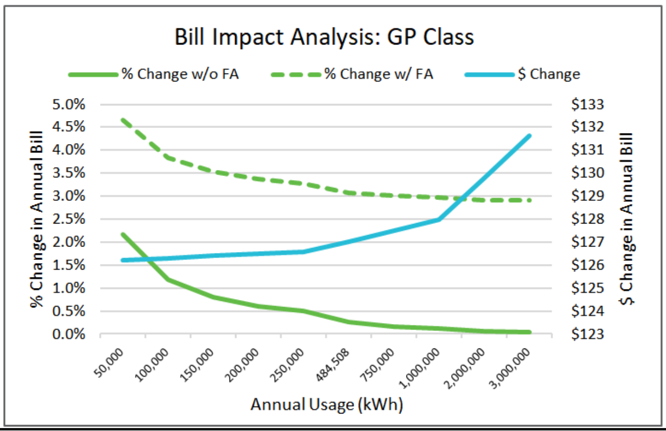
Bill Impact: General Power

Bill Impact Analysis - GP Rate										
			Base Rate Comparison				Annual Bill Comparison			
Annual Use	Cumulative Bills	Cumulative Use	Proposed Base Rates	Current Base Rates	Difference ($)	Difference (%)	Proposed Annual Bill	Current Annual Bill	Difference ($)	Difference (%)
50,000	2.1%	0.1%	$ 5,922	$ 5,796	$ 126	2.2%	$ 5,942	$ 5,676	$ 265	4.7%
100,000	10.0%	1.5%	10,884	10,758	126	1.2%	10,923	10,519	404	3.8%
150,000	28.0%	6.3%	15,846	15,720	126	0.8%	15,905	15,362	543	3.5%
200,000	41.7%	11.4%	20,808	20,682	126	0.6%	20,886	20,204	682	3.4%
250,000	49.4%	15.0%	25,770	25,643	127	0.5%	25,868	25,047	821	3.3%
484,508	74.0%	32.9%	49,043	48,916	127	0.3%	49,232	47,760	1,472	3.1%
750,000	85.0%	46.9%	75,390	75,263	128	0.2%	75,683	73,473	2,210	3.0%
1,000,000	89.7%	55.3%	100,200	100,072	128	0.1%	100,590	97,686	2,904	3.0%
2,000,000	96.7%	75.3%	199,440	199,310	130	0.1%	200,220	194,538	5,682	2.9%
3,000,000	98.2%	82.8%	298,680	298,549	132	0.0%	299,850	291,391	8,460	2.9%

Bill Impact calculated based on Average kW Demand Usage

The current annual bill includes a Tax Reform Credit of $0.00370 per kWh; Fuel Adjustment Charge of $0.00092; and EECR of $0.00039

The proposed annual bill includes no Fuel Adjustment Charge, no Tax Reform Credit (the test year amount is included in base rates); and EECR of $0.00039



Rate Design: SC-P

Empire District Electric (MISSOURI)
SC-P Rate Design

Base Revenues		Tax and FAC	Adjusted
Target Base Rates	4,319,429		4,319,429
Current Base Rates	4,213,435	(106,421)	4,107,014
$ Difference	105,994		212,414
% Difference	2.5%		5.2%

	Winter	Summer
On-Peak Period kWh	21,460,287	4,793,867
Shoulder Period kWh	-	6,733,233
Off-Peak Period kWh	24,448,121	12,302,847
Facility Demand kW	66,157	33,187
Billed Demand kW	65,745	33,042
Number of Bills	12	
Average Annual Use	69,738,355	

SC-P Rate Design	Rate	Units	Revenues
Proposed Rates			
Customer Charge	$ 275.00	12	$ 3,300
On-Peak Period kWh - Winter	$0.03927	21,460,287	842,689
Shoulder Period kWh - Winter	$0.00000	-	-
Off-Peak Period kWh - Winter	$0.03258	24,448,121	796,426
On-Peak Period kWh - Summer	$0.05537	4,793,867	265,443
Shoulder Period kWh - Summer	$0.04472	6,733,233	301,114
Off-Peak Period kWh - Summer	$0.03451	12,302,847	424,570
Facility Demand kW - Winter	$0.51	66,157	33,843
Billed Demand kW - Winter	$17.50	65,745	1,150,226
Facility Demand kW - Summer	$0.51	33,187	16,977
Billed Demand kW - Summer	$25.74	33,042	850,553
Other Adjustments			(365,712)
Revenue at Proposed Rates			$ 4,319,429
Current Rates			
Customer Charge	$ 259.01	12	$ 3,108
On-Peak Period kWh - Winter	$0.03838	21,460,287	823,646
Shoulder Period kWh - Winter	$0.00000	-	-
Off-Peak Period kWh - Winter	$0.03184	24,448,121	778,428
On-Peak Period kWh - Summer	$0.05412	4,793,867	259,444
Shoulder Period kWh - Summer	$0.04371	6,733,233	294,310
Off-Peak Period kWh - Summer	$0.03373	12,302,847	414,975
Facility Demand kW - Winter	0.50	66,157	33,078
Billed Demand kW - Winter	17.10	65,745	1,124,233
Facility Demand kW - Summer	0.50	33,187	16,594
Billed Demand kW - Summer	25.16	33,042	831,332
Other Adjustments			(365,712)
Revenue at Current Rates			$ 4,213,435

Rate Design: Total Electric Building

Empire District Electric (MISSOURI)
Total Electric Building Rate Design

Base Revenues		Tax and FAC	Adjusted
Target Base Rates	37,554,840		37,554,840
Current Base Rates	37,576,151	(1,130,646)	36,445,505
$ Difference	(21,311)		1,109,335
% Difference	-0.1%		3.0%

	Winter	Summer
First 150 Hours kWh	122,357,777	54,961,155
Next 200 Hours kWh	92,258,046	53,232,728
All Additional kWh	18,296,975	17,146,310
Facility Demand kW	1,149,074	571,481
Billed Demand kW	856,480	377,747
Number of Bills	11,354	
Average Annual Use	378,636	

Total Electric Building Rate Design	Rate	Units	Revenues
Proposed Rates			
Customer Charge	$ 72.00	11,354	$ 817,488
First 150 Hours - Winter	$0.08254	122,357,777	10,099,498
Next 200 Hours - Winter	$0.06690	92,258,046	6,172,495
All Additional - Winter	$0.06566	18,296,975	1,201,332
First 150 Hours - Summer	$0.10794	54,961,155	5,932,262
Next 200 Hours - Summer	$0.08454	53,232,728	4,500,102
All Additional - Summer	$0.07648	17,146,310	1,311,416
Facility Demand kW - Winter	$ 2.13	1,149,074	2,442,222
Billed Demand kW - Winter	$ 2.87	856,480	2,461,317
Facility Demand kW - Summer	$ 2.13	571,481	1,214,616
Billed Demand kW - Summer	$ 3.49	377,747	1,319,250
Other Adjustments			82,844
Revenue at Proposed Rates			$ 37,554,840
Current Rates			
Customer Charge	$ 69.49	11,354	$ 788,989
First 150 Hours - Winter	$0.08272	122,357,777	10,121,435
Next 200 Hours - Winter	$0.06705	92,258,046	6,185,902
All Additional - Winter	$0.06580	18,296,975	1,203,941
First 150 Hours - Summer	$0.10817	54,961,155	5,945,148
Next 200 Hours - Summer	$0.08472	53,232,728	4,509,877
All Additional - Summer	$0.07665	17,146,310	1,314,265
Facility Demand kW - Winter	2.13	1,149,074	2,447,527
Billed Demand kW - Winter	2.88	856,480	2,466,663
Facility Demand kW - Summer	2.13	571,481	1,217,254
Billed Demand kW - Summer	3.50	377,747	1,322,116
Other Adjustments			82,844
Revenue at Current Rates			$ 37,605,960

Bill Impact: Total Electric Building

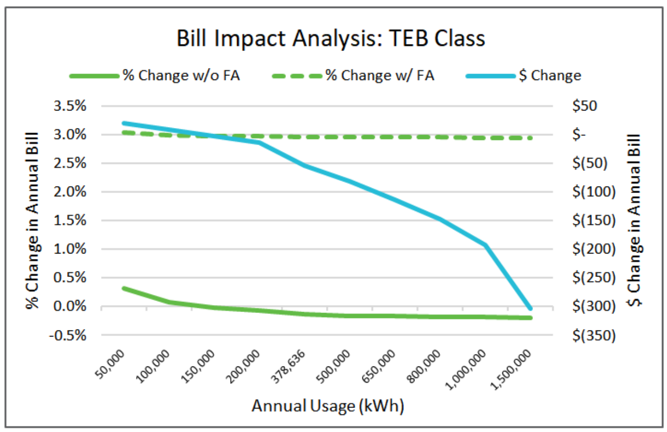
Bill Impact Analysis - TEB Rate

			Base Rate Comparison				Annual Bill Comparison			
Annual Use	Cumulative Bills	Cumulative Use	Proposed Base Rates	Current Base Rates	Difference ($)	Difference (%)	Proposed Annual Bill	Current Annual Bill	Difference ($)	Difference (%)
50,000	1.6%	0.1%	$ 5,980	$ 5,961	$ 19	0.3%	$ 5,999	$ 5,822	$ 177	3.0%
100,000	10.0%	1.8%	11,095	11,088	8	0.1%	11,134	10,811	323	3.0%
150,000	24.5%	6.4%	16,211	16,214	(3)	0.0%	16,270	15,800	470	3.0%
200,000	39.1%	12.8%	21,327	21,341	(14)	-0.1%	21,405	20,788	617	3.0%
378,636	67.1%	32.0%	39,604	39,658	(54)	-0.1%	39,752	38,611	1,141	3.0%
500,000	77.9%	44.0%	52,021	52,102	(81)	-0.2%	52,216	50,719	1,497	3.0%
650,000	84.1%	53.0%	67,368	67,483	(114)	-0.2%	67,622	65,685	1,937	2.9%
800,000	89.5%	62.9%	82,716	82,863	(148)	-0.2%	83,028	80,651	2,377	2.9%
1,000,000	95.0%	75.2%	103,179	103,371	(192)	-0.2%	103,569	100,605	2,964	2.9%
1,500,000	97.1%	81.8%	154,336	154,639	(303)	-0.2%	154,921	150,490	4,431	2.9%

Bill Impact calculated based on Average kW Demand Usage

The current annual bill includes a Tax Reform Credit of $0.00408 per kWh; Fuel Adjustment Charge of $0.00092; and EECR of $0.00039

The proposed annual bill includes no Fuel Adjustment Charge, no Tax Reform Credit (the test year amount is included in base rates); and EECR of $0.00039



Rate Design: Feed Mill and Grain Elevator Service

Empire District Electric (MISSOURI)
Feed Mill and Grain Elevator Service (PFM)

Base Revenues		Tax and FAC	Adjusted
Target Base Rates	74,388		74,388
Current Base Rates	75,162	(1,931)	73,231
$ Difference	(774)		1,157
% Difference	-1.0%		1.6%
	Winter	**Summer**	
Annual Usage - First Block	38,668	21,215	700
Annual Usage - Second Block	234,700	125,600	
Annual Usage - Third Block	-	-	
Number of Bills	120		
Average Annual Use (kWh)	42,018		

Feed Mill and Grain Elevator Service (PFM)	Rate	Units	Revenues
Proposed Rates			
Customer Charge	$ 28.50	120	$ 3,420
1st Block kWh - Winter	$ 0.17800	38,668	6,883
2nd Block kWh - Winter	$ 0.16170	234,700	37,952
1st Block kWh - Summer	$ 0.17800	21,215	3,776
2nd Block kWh - Summer	$ 0.17800	125,600	22,357
Revenue at Proposed Rates			$ 74,388
Current Rates			
Customer Charge	$ 27.65	120	$ 3,318
1st Block kWh - Winter	$0.18020	38,668	6,968
2nd Block kWh - Winter	$0.16370	234,700	38,420
1st Block kWh - Summer	$0.18020	21,215	3,823
2nd Block kWh - Summer	$0.18020	125,600	22,633
Revenue at Current Rates			$ 75,162

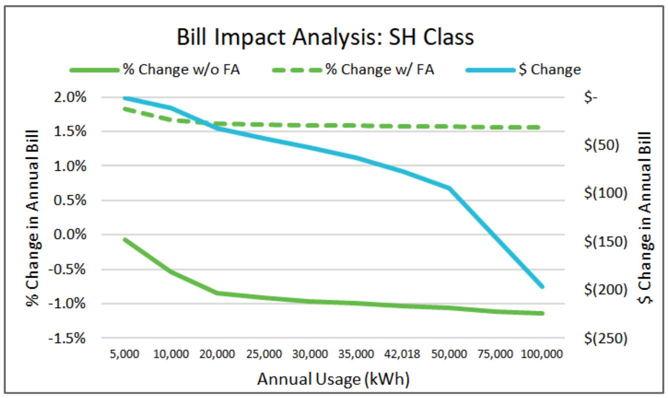
Bill Impact: Feed Mill and Grain Elevator Service

Bill Impact Analysis - PFM Rate

Annual Use	Cumulative Bills	Cumulative Use	Base Rate Comparison: Proposed Base Rates	Base Rate Comparison: Current Base Rates	Base Rate Comparison: Difference ($)	Base Rate Comparison: Difference (%)	Annual Bill Comparison: Proposed Annual Bill	Annual Bill Comparison: Current Annual Bill	Annual Bill Comparison: Difference ($)	Annual Bill Comparison: Difference (%)
5,000	25.0%	1.8%	$ 1,232	$ 1,233	$ (1)	-0.1%	$ 1,234	$ 1,212	$ 22	1.8%
10,000	50.0%	5.1%	2,094	2,105	(11)	-0.5%	2,098	2,063	35	1.7%
20,000	62.5%	9.5%	3,769	3,801	(32)	-0.8%	3,777	3,717	60	1.6%
25,000	62.5%	9.5%	4,603	4,645	(42)	-0.9%	4,613	4,540	72	1.6%
30,000	62.5%	9.5%	5,437	5,489	(53)	-1.0%	5,448	5,363	85	1.6%
35,000	62.5%	9.5%	6,270	6,333	(63)	-1.0%	6,284	6,186	98	1.6%
42,018	75.0%	19.5%	7,441	7,519	(77)	-1.0%	7,457	7,342	116	1.6%
50,000	75.0%	19.5%	8,772	8,866	(94)	-1.1%	8,792	8,656	136	1.6%
75,000	75.0%	19.5%	12,942	13,087	(145)	-1.1%	12,971	12,772	199	1.6%
100,000	87.5%	42.2%	17,111	17,308	(197)	-1.1%	17,150	16,888	263	1.6%

The current annual bill includes a Tax Reform Credit of $0.00552 per kWh; Fuel Adjustment Charge of $0.00092; and EECR of $0.00039

The proposed annual bill includes no Fuel Adjustment Charge, no Tax Reform Credit (the test year amount is included in base rates); and EECR of $0.00039



Rate Design: Large Power

Empire District Electric (MISSOURI)
Large Power Rate Design

Base Revenues		Tax and FAC	Adjusted
Target Base Rates	65,260,219		65,260,219
Current Base Rates	63,671,103	(1,656,934)	62,014,169
$ Difference	1,589,116		3,246,049
% Difference	2.5%		5.2%

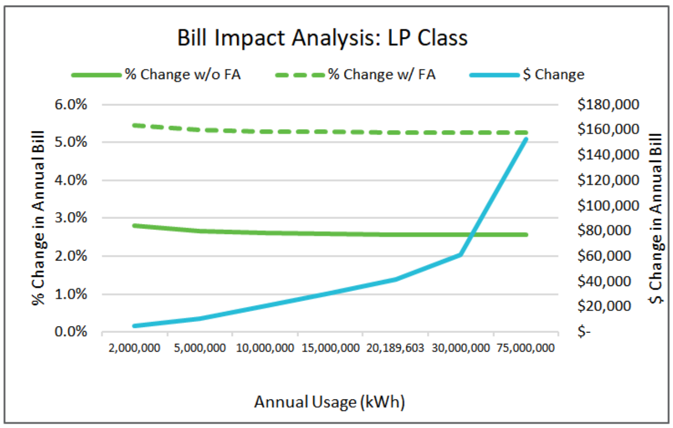
	Winter	Summer
First 350 Hours	345,003,843	190,469,309
All Additional	169,992,372	100,436,126
Facility Demand kW	1,110,406	549,859
Billed Demand kW	1,003,759	553,295
Number of Bills	479	
Average Annual Use	20,189,603	

Large Power Rate Design	Rate	Units	Revenues
Proposed Rates			
Customer Charge	$ 325.00	479	$ 155,675
First 350 Hours - Winter	$0.06048	345,003,843	20,865,832
All Additional - Winter	$0.03552	169,992,372	6,038,129
First 350 Hours - Summer	$0.06809	190,469,309	12,969,055
All Additional - Summer	$0.03683	100,436,126	3,699,063
Facility Demand kW - Winter	$ 2.86	1,110,406	3,180,024
Billed Demand kW - Winter	$ 8.66	1,003,759	8,692,554
Facility Demand kW - Summer	$ 2.86	549,859	1,574,709
Billed Demand kW - Summer	$ 15.69	553,295	8,681,205
Other Adjustments			(596,027)
Revenue at Proposed Rates			$ 65,260,219
Current Rates			
Customer Charge	$ 283.55	479	$ 135,820
First 350 Hours - Winter	$0.06048	345,003,843	20,865,832
All Additional - Winter	$0.03552	169,992,372	6,038,129
First 350 Hours - Summer	$0.06809	190,469,309	12,969,055
All Additional - Summer	$0.03683	100,436,126	3,699,063
Facility Demand kW - Winter	1.88	1,110,406	2,087,562
Billed Demand kW - Winter	8.66	1,003,759	8,692,554
Facility Demand kW - Summer	1.88	549,859	1,033,736
Billed Demand kW - Summer	15.69	553,295	8,681,205
Other Adjustments			(596,027)
Revenue at Current Rates			$ 63,606,930

Bill Impact: Large Power

Bill Impact Analysis - LP Rate										
			Base Rate Comparison				Annual Bill Comparison			
Annual Use	Cumulative Bills	Cumulative Use	Proposed Base Rates	Current Base Rates	Difference ($)	Difference (%)	Proposed Annual Bill	Current Annual Bill	Difference ($)	Difference (%)
2,000,000			$ 166,949	$ 162,398	$ 4,551	2.8%	$ 167,729	$ 159,066	$ 8,663	5.4%
5,000,000			411,522	400,890	10,632	2.7%	413,472	392,560	20,912	5.3%
10,000,000			819,143	798,377	20,766	2.6%	823,043	781,717	41,326	5.3%
15,000,000			1,226,765	1,195,865	30,900	2.6%	1,232,615	1,170,875	61,740	5.3%
20,189,603			1,649,843	1,608,425	41,419	2.6%	1,657,717	1,574,789	82,928	5.3%
30,000,000			2,449,629	2,388,326	61,303	2.6%	2,461,329	2,338,346	122,983	5.3%
75,000,000			6,118,223	5,965,712	152,510	2.6%	6,147,473	5,840,762	306,710	5.3%

Bill Impact calculated based on Average kW Demand Usage
The current annual bill includes a Tax Reform Credit of $0.00298 per kWh; Fuel Adjustment Charge of $0.00092; and EECR of $0.00039
The proposed annual bill includes no Fuel Adjustment Charge, no Tax Reform Credit (the test year amount is included in base rates); and EECR of $0.00039



Rate Design: Miscellaneous Service

Empire District Electric (MISSOURI)			
Miscellaneous Service (MS)			
Base Revenues		Tax and FAC	Adjusted
Target Base Rates	15,441		15,441
Current Base Rates	14,828	(236)	14,592
$ Difference	613		849
% Difference	4.1%		5.8%
	kWh Usage		
All Usage	138,894		
Number of Bills	36		
Average Annual Use (kWh)	46,298		

Miscellaneous Service (MS)	Rate	Units	Revenues
Proposed Rates			
Customer Charge	$ 21.00	36	$ 756
All Usage	$0.10573	138,894	14,685
Other Adjustments			-
Revenue at Proposed Rates			$ 15,441
Current Rates			
Customer Charge	$ 19.51	36	$ 702
All Usage	$0.10170	138,894	14,126
Other Adjustments			-
Revenue at Current Rates			$ 14,828

Rate Design: Municipal Street Lighting

Empire District Electric (MISSOURI)
Street Lighting Rate Design

Base Revenues		Tax and FAC	Adjusted
Target Base Rates	2,387,607		2,387,607
Current Base Rates	2,295,418	(113,321)	2,182,097
$ Difference	92,188		205,509
% Difference	4.0%		9.4%

	kWh Usage
Annual Usage	22,413,186
Number of Bills	84
Average Annual Use (kWh)	3,201,884

Street Lighting - SPL Rate Design	Current Charges	Proposed Increase	Proposed Charges
Facilities Charges			
Incandascent Lamp Sizes			
4,000 Lumen	$ 65.55	$ 2.63	68.18
Mercury Vapor Lamp Sizes			
7,000 Lumen Mercury	$ 89.02	$ 3.58	92.60
11,000 Lumen Mercury	$ 106.85	$ 4.29	111.14
20,000 Lumen Mercury	$ 152.97	$ 6.14	159.11
53,000 Lumen Mercury	$ 258.08	$ 10.36	268.44
High Pressure Sodium Vapor Lamp Sizes			
6,000 Lumen HP Sodium	$ 83.42	$ 3.35	86.77
16,000 Lumen HP Sodium	$ 104.43	$ 4.19	108.62
27,500 Lumen HP Sodium	$ 135.91	$ 5.46	141.37
50,000 Lumen HP Sodium	$ 193.68	$ 7.78	201.46
130,000 Lumen HP Sodium	$ 312.56	$ 12.55	325.11
Metal Halide Lamp Sizes			
12,000 Lumen MetalH	$ 130.55	$ 5.24	135.79
20,500 Lumen MetalH	$ 159.99	$ 6.43	166.42
36,000 Lumen MetalH	$ 214.03	$ 8.60	222.63
110,000 Lumen MetalH	$ 472.96	$ 18.99	491.95

Rate Design: Private Lighting

Empire District Electric (MISSOURI)
Private Lighting Rate Design

Base Revenues		Tax and FAC	Adjusted
Target Base Rates	4,217,121		4,217,121
Current Base Rates	4,207,722	(129,948)	4,077,774
$ Difference	9,399		139,347
% Difference	0.2%		3.4%

	kWh Usage
Annual Usage	12,922,453
Number of Bills	3,019

Private Lighting - PL Rate Design	Current Charges	Proposed Increase	Proposed Charges
Installation Charge: Standard Street Lighting			
Mercury Vapor Lamp Sizes			
6,800 Lumen Std Mercury	$ 15.79	$ 0.04	15.83
20,000 Lumen Std Mercury	26.28	$ 0.06	26.34
54,000 Lumen Std Mercury	50.37	$ 0.11	50.48
Sodium Vapor Lamp Sizes			
6,000 Lumen Std Sodium	14.58	$ 0.03	14.61
16,000 Lumen Std Sodium	21.22	$ 0.05	21.27
27,500 Lumen Std Sodium	30.67	$ 0.07	30.74
50,000 Lumen Std Sodium	35.57	$ 0.08	35.65
Metal Halide Lamp Sizes			
12,000 Lumen Std MetalH	24.60	$ 0.05	24.65
20,500 Lumen Std MetalH	32.83	$ 0.07	32.90
36,000 Lumen Std MetalH	36.83	$ 0.08	36.91
Installation Charge: Standard Flood Lighting			
Mercury Vapor Lamp Sizes			
20,000 Lumen Mercury FL	36.83	$ 0.08	36.91
54,000 Lumen Mercury FL	60.81	$ 0.14	60.95
Sodium Vapor Lamp Sizes			
27,500 Lumen Sodium FL	35.68	$ 0.08	35.76
50,000 Lumen Sodium FL	48.94	$ 0.11	49.05
140,000 Lumen Sodium FL	71.51	$ 0.16	71.67
Metal Halide Lamp Sizes			
12,000 Lumen MetalH FL	25.52	$ 0.06	25.58
20,500 Lumen MetalH FL	33.79	$ 0.08	33.87
36,000 Lumen MetalH FL	49.82	$ 0.11	49.93
110,000 Lumen MetalH FL	72.80	$ 0.16	72.96
Additional Charges			
Regular Wood Pole	2.03	$ 0.00	2.03
Transformer	2.03	$ 0.00	2.03
Guy and Anchor	2.03	$ 0.00	2.03
Conductor	0.02	$ 0.00	0.02

Rate Design: Special Lighting

Empire District Electric (MISSOURI)
Special Lighting Rate Design

Base Revenues		Tax and FAC	Adjusted
Target Base Rates	139,978		139,978
Current Base Rates	135,386	(4,484)	130,902
$ Difference	4,592		9,076
% Difference	3.4%		6.9%
	kWh Usage		
Annual Usage - First Block	443,437	1000	
Annual Usage - Second Block	324,906		
Number of Bills	1,510		
Average Annual Use (kWh)	6,106		

Special Lighting Rate Design	Rate	Units	Revenues
Proposed Rates			
Customer Charge	$ -	1,510	$ -
1st Block kWh	$0.17812	443,437	78,986
2nd Block kWh	$0.13966	324,906	45,377
Other Adjustments			15,616
Revenue at Proposed Rates			$ 139,978
Current Rates			
Customer Charge	$ -	1,510	$ -
1st Block kWh	$0.17460	443,437	77,424
2nd Block kWh	$0.13690	324,906	44,480
Other Adjustments			15,616
Revenue at Current Rates			$ 137,519

Summary Customer Bill Impacts

The Empire District Electric Company
Schedule 3, Page 1 of 1
4 CSR 240-3.030(3)(B)(3)(4)(5)

Class	Average Customer Count	Average Annual Customer Impact: Bill Change $	[1] Average Annual Customer Impact: Bill Change %	Aggregate Annual Change	[1] Aggregate Annual % Change
RG-Residential	130,887	$ 96.24	5.8%	$ 12,596,881	5.8%
CB-Commercial	18,072	$ 125.82	5.2%	$ 2,273,755	5.2%
SH-Small Heating	3,028	$ 164.22	5.0%	$ 497,260	5.0%
GP-General Power	1,793	$ 1,476.02	3.1%	$ 2,646,498	3.1%
SC-P PRAXAIR Transmission	1	$ 212,414.31	5.1%	$ 212,414	5.1%
TEB-Total Electric Bldg	946	$ 1,172.45	3.0%	$ 1,109,335	3.0%
PFM-Feed Mill/Grain Elev	10	$ 115.67	1.6%	$ 1,157	1.6%
LP-Large Power	40	$ 81,320.65	5.2%	$ 3,246,049	5.2%
MS-Miscellaneous	3	$ 282.94	5.8%	$ 849	5.8%
SPL-Municipal St Lighting	7	$ 29,358.47	9.4%	$ 205,509	9.4%
PL-Private Lighting	252	$ 553.88	3.4%	$ 139,347	3.4%
LS-Special Lighting	126	$ 72.13	6.9%	$ 9,076	6.9%
Total Customers	155,165			$ 22,938,132	4.9%

The proposed annual bill reflects no Fuel Adjustment Charge, no Tax Reform Credit; and EECR charge of $0.00039 per kWh
The current annual bill reflects each class' Tax Reform Credits; a Fuel Adjustment Charge of $0.00092 per kWh; and a EECR of $0.00039 per kWh

Customer Costs (1/2)

Empire District Electric (MISSOURI) Summary of Costs	Total Company	Res Gen RG	Comm CB	Small Heating SH	Gen Pow GP	Prax SC-P
Customer Charges						
Proposed		$ 19.00	$ 25.00	$ 25.00	$ 80.00	$ 275.00
Current		$ 13.00	$ 22.69	$ 22.69	$ 69.49	$ 259.01
Billing Determinants						
Customers	155,165	130,887	18,072	3,028	1,793	1
Usage (MWh)	4,212,506	1,671,631	316,608	84,989	868,722	69,738
Revenue Requirement	$ 564,661,907	$ 259,168,268	$ 51,668,554	$ 12,045,819	$ 103,420,656	$ 5,453,290
Customer Costs						
Basic customer costs	$ 58,830,706	$ 45,464,833	$ 7,072,630	$ 1,178,813	$ 994,936	$ 16,120
$ per customer	$ 31.60	$ 28.95	$ 32.61	$ 32.44	$ 46.24	$ 1,343.37
Fully-loaded customer costs	$ 106,387,152	$ 84,517,415	$ 12,072,533	$ 2,006,250	$ 1,468,674	$ 44,420
$ per customer	$ 57.14	$ 53.81	$ 55.67	$ 55.21	$ 68.26	$ 3,701.70
Revenue Requirement						
Revenue Requirement	$ 564,661,907	$ 259,168,268	$ 51,668,554	$ 12,045,819	$ 103,420,656	$ 5,453,290
$ per customer	$ 303.26	$ 165.01	$ 238.25	$ 331.51	$ 4,806.69	$ 454,440.87
$ per MWh	$ 1,340.44	$ 1,550.39	$ 1,631.94	$ 1,417.34	$ 1,190.49	$ 781.96

Customer Costs (2/2)

Empire District Electric (MISSOURI) Summary of Costs	Total Elect Bldg TEB	Feed Mill PFM	Large Power LP	Misc. Service MS	Street Lts SPL	Private Lts PL	Spec Lts LS
Customer Charges							
Proposed	$ 72.00	$ 28.50	$ 325.00	$ 21.00			$ -
Current	$ 69.49	$ 27.65	$ 283.55	$ 19.51			$ -
Billing Determinants							
Customers	946	10	40	3	7	252	126
Usage (MWh)	358,253	420	805,902	139	22,413	12,922	768
Revenue Requirement	$ 43,993,442	$ 82,592	$ 80,437,148	$ 17,840	$ 3,712,178	$ 4,507,643	$ 154,478
Customer Costs							
Basic customer costs	$ 521,987	$ 4,842	$ 507,832	$ 2,984	$ 2,020,741	$ 939,177	$ 105,811
$ per customer	$ 45.97	$ 40.35	$ 1,060.19	$ 82.89	$ 24,056.44	$ 311.09	$ 70.07
Fully-loaded customer costs	$ 793,534	$ 8,087	$ 1,361,331	$ 11,302	$ 2,819,192	$ 1,153,346	$ 131,067
$ per customer	$ 69.89	$ 67.39	$ 2,842.03	$ 313.95	$ 33,561.81	$ 382.03	$ 86.80
Revenue Requirement							
Revenue Requirement	$ 43,993,442	$ 82,592	$ 80,437,148	$ 17,840	$ 3,712,178	$ 4,507,643	$ 154,478
$ per customer	$ 3,874.71	$ 688.26	$ 167,927.24	$ 495.55	$ 44,192.60	$ 1,493.09	$ 102.30
$ per MWh	$ 1,228.00	$ 1,965.61	$ 998.10	$ 1,284.41	$ 1,656.25	$ 3,488.23	$ 2,010.54

Lead-Lag Summary Test Year Ending March 31, 2019

Line	Description	Revenue Requirement Amount	Average Daily Amount	Revenue Lag	Ref.	Expense Lead	Ref.	Net (Lead)/Lag Days	Working Capital Requirement
1	Purchased Fuel and Power Expenses	$ 140,548,512	385,064	42.13	A	(31.13)	B	11.00	$ 4,235,709
2	Operation and Maintenance Expenses								
3	O&M, Labor	$ 32,381,159	88,716	42.13	A	(12.00)	C	30.13	$ 2,672,998
4	401-K	20,160,881	55,235	42.13	A	(12.00)	C	30.13	1,664,239
5	Post Retirement Benefits	173,562	476	42.13	A	(5.66)	C	36.47	17,342
6	Medical, Vision, and Dental Expenses	5,817,287	15,938	42.13	A	(16.29)	C	25.84	411,832
7	Life Insurance / AD&D	274,469	752	42.13	A	(16.34)	C	25.79	19,393
8	Intercompany Transfers	15,102,774	41,377	42.13	A	(35.13)	C	7.00	289,642
9	PSC Assessment	1,084,117	2,970	42.13	A	17.23	C	59.36	176,310
10	O&M, Other Non-Labor	119,098,162	326,296	42.13	A	(29.21)	C	12.92	4,215,749
11	Total O&M Expenses	$ 194,092,414							$ 9,467,506
12	Taxes Other Than Income Taxes								
13	Property Taxes	$ 25,261,712	69,210	42.13	A	(195.13)	E	(153.00)	$ (10,589,156)
14	Payroll Taxes	2,611,190	7,154	42.13	A	(11.17)	E	30.96	221,486
15	Total Taxes Other Than Income Taxes	$ 27,872,902							$ (10,367,670)
16	Federal and State Income Taxes	$ 10,996,093	30,126	42.13	A	(37.00)	D	5.13	$ 154,548
17	Interest Payments	33,682,431	92,281	42.13	A	(91.26)	F	(49.13)	(4,533,748)
18	Total	$ 407,192,351	1,115,595						$ (1,043,655)

Lead Lag Supporting Schedules Revenue and Collection Lag
Test Year Ending March 31, 2019

Line	Description	Revenue Lag	Reference
1	Service Lag	15.21	
2	Billing Lag	5.21	WP (A)
3	Collection Lag	21.71	WP (A)
4	Composite Revenue Lag	42.13	

Lead Lag Supporting Schedules Purchase Fuel and Power
Test Year Ending March 31, 2019

Line	Description		Amount	(Lead)/Lag Days	Reference		Weighted Dollar Amount
1	Purchased Fuel and Power						
2	Coal	$	42,982,825	(11.78)	B-1	$	(506,228,571)
3	Natural Gas		65,787,361	(38.95)	B-2		(2,562,270,761)
4	Fuel Oil and Tires		3,002,351	(13.49)	B-3		(40,487,578)
5	Power		103,834,870	(34.71)	B-4		(3,603,673,324)
6	Total Purchased Fuel and Power Expenses	$	215,607,407	(31.13)		$	(6,712,660,234)

Lead Lag Supporting Schedules Operations and Maintenance Expenses
Test Year Ending March 31, 2019

Line	Description	(Lead)/Lag Days	Reference
1	Operation and Maintenance Expenses		
2	O&M, Labor	(12.00)	C-1
3	401-K	(12.00)	C-2
4	Post Retirement Benefits	(5.66)	C-3
5	Medical, Vision, and Dental Expenses	(16.29)	C-4
6	Life Insurance / AD&D	(16.34)	C-5
7	Intercompany Transfers	(35.13)	C-6
8	PSC Assessment	17.23	C-7
9	O&M, Other Non-Labor	(29.21)	C-8
10	Total O&M Expenses		

Lead Lag Supporting Schedules Federal Income Taxes
Test Year Ending March 31, 2019

Line	Description	Service Period Start	Service Period End	Midpoint of Service Period	Payment Date	Percent of Taxes Due	(Lead)/Lag Days Days from Midpoint to Payment Date	(Lead)/Lag Days
1	Third Quarter	1/1/2017	12/31/2017	(182.50)	9/15/2017	25.0%	(75.5)	(18.9)
2	Fourth Quarter	1/1/2017	12/31/2017	(182.50)	12/15/2017	25.0%	(166.5)	(41.6)
3	First Quarter	1/1/2018	12/31/2018	(182.50)	4/15/2018	25.0%	77.5	19.4
4	Second Quarter	1/1/2018	12/31/2018	(182.50)	6/15/2018	25.0%	16.5	4.1
5	Federal Income Tax Lead / (Lag) Days							(37.0)

Lead Lag Supporting Schedules Taxes Other than Income Tax
Test Year Ending March 31, 2019

Line	Description		Amount	(Lead)/Lag Days	Reference		Weighted Dollar Amount
1	Payroll Taxes						
2	FICA	$	22,335,685	(11.0)	E-1	$	(245,692,540)
3	Federal Income Taxes Withheld		20,164,615	(11.0)	E-2		(221,810,761)
4	State Income Taxes Withheld		340,877	(11.0)	E-3		(3,749,649)
5	Federal Unemployment		83,680	(75.2)	E-4		(6,291,250)
6	State Unemployment		32,388	(75.2)	E-5		(2,434,444)
7	Total Payroll Taxes	$	42,957,245	(11.2)			(479,978,644)
8	Property Taxes	$	22,767,628	(195.1)	E-6		(4,442,535,712)
9	Total Taxes Other Than Income Taxes	$	65,724,873	(74.9)			(4,922,514,356)

Lead Lag Supporting Schedules Interest Payments
Test Year Ending March 31, 2019

Line	Description	Service Period Start	Service Period End	Midpoint of Service Period	Payment Date	Cleared Check Dt	Amount	Check Lag	Payment Lag	(Lead)/Lag Days	Weighted Dollar Amount	Composite (Lead)/Lag Days
1	Bank Of New York	2/22/2017	8/21/2017	(90.5)	8/21/2017	8/21/2017	$ 1,077,000	0.0	(90.5)	(90.5)	$ (97,468,500)	
2	Bank Of New York	3/2/2017	9/1/2017	(92.0)	9/1/2017	9/1/2017	1,300,000	0.0	(92.0)	(92.0)	(119,600,000)	
3	Bank Of New York	4/3/2017	10/2/2017	(91.5)	10/2/2017	10/2/2017	1,575,200	0.0	(91.5)	(91.5)	(144,130,800)	
4	Bank Of New York	4/3/2017	10/2/2017	(91.5)	10/2/2017	10/2/2017	2,350,000	0.0	(91.5)	(91.5)	(215,025,000)	
5	Wells Fargo Bank, N.A.	5/16/2017	11/15/2017	(92.0)	11/15/2017	11/15/2017	2,077,000	0.0	(92.0)	(92.0)	(191,084,000)	
6	Bank Of New York	5/31/2017	11/30/2017	(92.0)	11/30/2017	11/30/2017	559,500	0.0	(92.0)	(92.0)	(51,474,000)	
7	Bank Of New York	5/31/2017	11/30/2017	(92.0)	11/30/2017	11/30/2017	2,592,000	0.0	(92.0)	(92.0)	(238,464,000)	
8	Bank Of New York	6/2/2017	12/1/2017	(91.5)	12/1/2017	12/1/2017	1,281,000	0.0	(91.5)	(91.5)	(117,211,500)	
9	Bank Of New York	6/2/2017	12/1/2017	(91.5)	12/1/2017	12/1/2017	2,325,000	0.0	(91.5)	(91.5)	(212,737,500)	
10	Bank Of New York	6/2/2017	12/1/2017	(91.5)	12/1/2017	12/1/2017	2,868,750	0.0	(91.5)	(91.5)	(262,490,625)	
11	Wells Fargo Bank, N.A.	7/3/2017	1/2/2018	(92.0)	1/2/2018	1/2/2018	1,160,000	0.0	(92.0)	(92.0)	(106,720,000)	
12	Bank Of New York	8/21/2017	2/20/2018	(92.0)	2/20/2018	2/20/2018	1,077,000	0.0	(92.0)	(92.0)	(99,084,000)	
13	Bank Of New York	9/2/2017	3/1/2018	(90.5)	3/1/2018	3/1/2018	1,300,000	0.0	(90.5)	(90.5)	(117,650,000)	
14	Bank Of New York	10/3/2017	4/2/2018	(91.0)	4/2/2018	4/2/2018	1,575,200	0.0	(91.0)	(91.0)	(143,343,200)	
15	Bank Of New York	10/3/2017	4/2/2018	(91.0)	4/2/2018	4/2/2018	2,350,000	0.0	(91.0)	(91.0)	(213,850,000)	
16	Wells Fargo Bank, N.A.	11/16/2017	5/15/2018	(90.5)	5/15/2018	5/15/2018	2,077,000	0.0	(90.5)	(90.5)	(187,968,500)	
17	Bank Of New York	12/1/2017	5/30/2018	(90.5)	5/30/2018	5/30/2018	559,500	0.0	(90.5)	(90.5)	(50,634,750)	
18	Bank Of New York	12/1/2017	5/30/2018	(90.5)	5/30/2018	5/30/2018	2,592,000	0.0	(90.5)	(90.5)	(234,576,000)	
19	Bank Of New York	12/2/2017	6/1/2018	(91.0)	6/1/2018	6/1/2018	1,281,000	0.0	(91.0)	(91.0)	(116,571,000)	
20	Bank Of New York	12/2/2017	6/1/2018	(91.0)	6/1/2018	6/1/2018	1,875,500	0.0	(91.0)	(91.0)	(170,670,500)	
21	Bank Of New York	12/2/2017	6/1/2018	(91.0)	6/1/2018	6/1/2018	2,325,000	0.0	(91.0)	(91.0)	(211,575,000)	
22	Bank Of New York	12/2/2017	6/1/2018	(91.0)	6/1/2018	6/1/2018	2,868,750	0.0	(91.0)	(91.0)	(261,056,250)	
23	Subtotal						$ 39,046,400				$ (3,563,385,125)	(91.3)

<u>**AFFIDAVIT OF TIMOTHY S. LYONS**</u>

STATE OF VERMONT)
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On the 8th day of August, 2019, before me appeared Timothy S. Lyons, to me personally known, who, being by me first duly sworn, states that he a partner at ScottMadden, Inc and acknowledges that he has read the above and foregoing document and believes that the statements therein are true and correct to the best of his information, knowledge and belief.

Timothy S. Lyons

Timothy S. Lyons

Subscribed and sworn to before me this 8th day of August, 2019.

Notary Public

My commission expires: 01/31/2021

Kevin Lemieux NOTARY PUBLIC VERMONT