

Exhibit No.: \_\_\_\_\_  
Issue(s): Class Cost of Service Study and  
Rate Design  
Witness: Timothy S. Lyons  
Type of Exhibit: Direct Testimony  
Sponsoring Party: The Empire District  
Electric Company d/b/a Liberty  
Case No.: ER-2024-0261  
Date Testimony Prepared: November 2024

**Before the Public Service Commission  
of the State of Missouri**

**Direct Testimony**

**of**

**Timothy S. Lyons**

**on behalf of**

**The Empire District Electric Company d/b/a Liberty**

**November 6, 2024**



TABLE OF CONTENTS  
FOR THE DIRECT TESTIMONY OF TIMOTHY S. LYONS  
THE EMPIRE DISTRICT ELECTRIC COMPANY D/B/A LIBERTY  
BEFORE THE MISSOURI PUBLIC SERVICE COMMISSION  
CASE NO. ER-2024-0261

| <b>SUBJECT</b>                                | <b>PAGE</b> |
|---|-------------|
| I. INTRODUCTION.....                          | 1           |
| II. OVERVIEW.....                             | 2           |
| III. REVENUE ADJUSTMENTS.....                 | 7           |
| IV. ALLOCATED COST OF SERVICE STUDY.....      | 9           |
| V. OVERVIEW OF RATE DESIGN.....               | 27          |
| VI. RATE DESIGN AND BILL IMPACT ANALYSES..... | 29          |
| VII. COMMITMENTS FROM OTHER CASES.....        | 33          |
| VIII. CASH WORKING CAPITAL REQUIREMENT.....   | 34          |
| IX. CONCLUSION.....                           | 35          |

DIRECT TESTIMONY OF TIMOTHY S. LYONS  
THE EMPIRE DISTRICT ELECTRIC COMPANY D/B/A LIBERTY  
BEFORE THE MISSOURI PUBLIC SERVICE COMMISSION  
CASE NO. ER-2024-0261

1 **I. INTRODUCTION**

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

3 A. My name is Timothy S. Lyons. My business address is 3 Speen Street, Suite 150,  
4 Framingham, Massachusetts 01701.

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

6 A. I am a Partner at ScottMadden, Inc. (“ScottMadden”).

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

8 A. I am testifying on behalf of The Empire District Electric Company d/b/a Liberty  
9 (“Liberty” or “Company”).

10 **Q. Please describe your professional and educational experience.**

11 A. I have more than 30 years of experience in the energy industry. I started my career in  
12 1985 at Boston Gas Company, eventually becoming Director of Rates and Revenue  
13 Analysis. In 1993, I moved to Providence Gas Company, eventually becoming Vice  
14 President of Marketing and Regulatory Affairs. Starting in 2001, I held a number of  
15 management consulting positions in the energy industry, first at KEMA and then at  
16 Quantec, LLC. In 2005, I became Vice President of Sales and Marketing at Vermont  
17 Gas Systems, Inc. before joining Sussex Economic Advisors, LLC (“Sussex”) in 2013.  
18 Sussex was acquired by ScottMadden in 2016.

19 I hold a bachelor’s degree from St. Anselm College, a master’s degree in  
20 economics from The Pennsylvania State University, and a master’s degree in business  
21 administration from Babson College.

1 **Q. Have you previously testified before the Missouri Public Service Commission**  
2 **(“Commission”)?**

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

4 **Q. What is the purpose of your direct testimony?**

5 A. The purpose of my testimony is to sponsor the Company’s proposed retail base rates,  
6 the Company’s compliance with various stipulations/agreements, and the Company’s  
7 lead/lag days associated with test year revenues and expenses. Furthermore, my direct  
8 testimony includes a description of: (a) the Company’s current rate classes and base  
9 rates; (b) the Company’s revenue normalization, annualization, and load growth  
10 process; (c) the Class Cost of Service Study (“COSS”); and (d) the proposed class  
11 revenue requirements, rate design, and customer bill impacts for each rate class.

12 **Q. Have you prepared schedules to support this testimony?**

13 A. Yes. Direct Schedules TSL-2 through TSL-5 summarize the results of the COSS, the  
14 proposed base rates, and customer bill impacts.

- 15 • Direct Schedule TSL-2: Class Cost of Service Study Summary
- 16 • Direct Schedule TSL-3: Class Cost of Service Study Schedules
- 17 • Direct Schedule TSL-4: Class Revenue Requirements
- 18 • Direct Schedule TSL-5: Rate Design and Bill Impacts

19 These Schedules were prepared by me or under my direction.

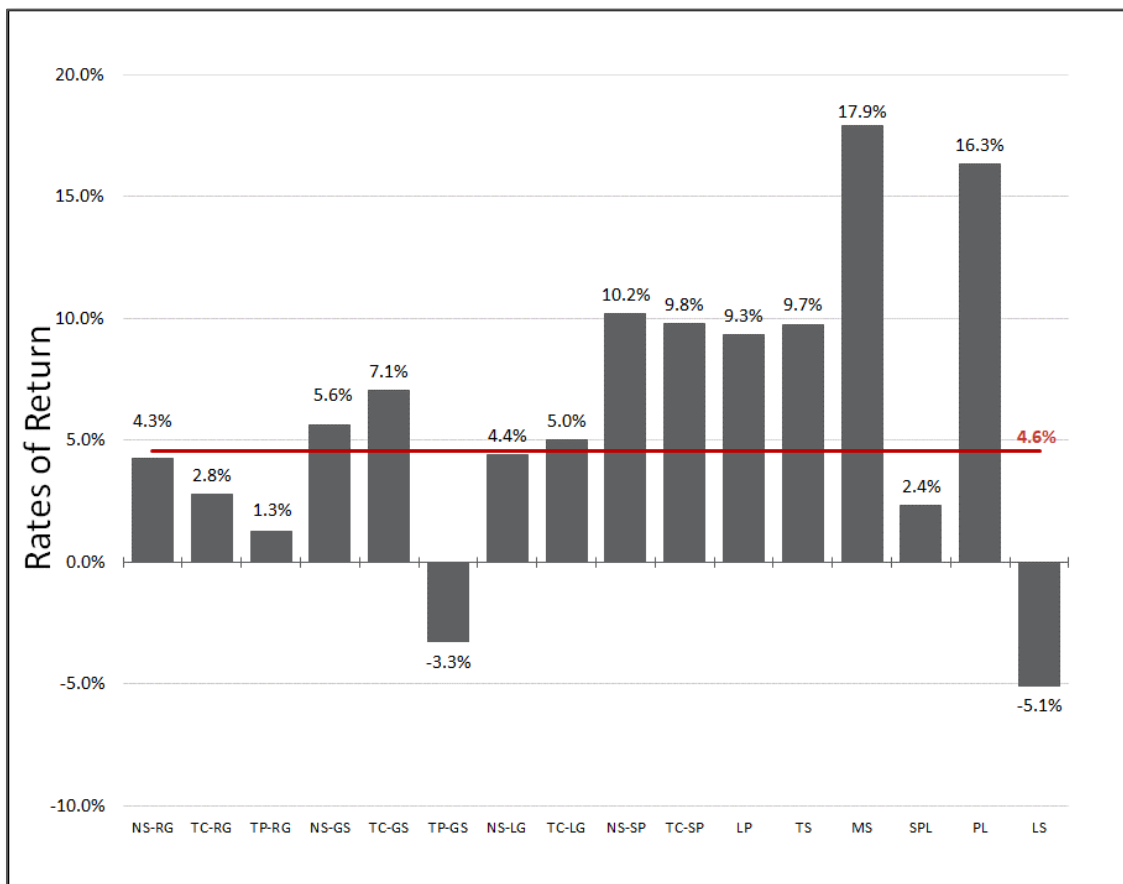
20 **II. OVERVIEW**

21 **Q. Please summarize your direct testimony.**

22 A. The results of the Company’s COSS show differences in class rates of return (“ROR”)  
23 at current base rates as compared to the system or overall ROR, as shown in Figure 1  
24 (below).

1

**Figure 1: COSS Results**



2

3

4

5

6

7

8

9

10

11

12

The Figure shows several rate classes, such as the Non-Standard Residential (Schedule “NS-RG”), Time Choice Residential (Schedule “TC-RG”), Time Choice Plus Residential (Schedule “TP-RG”), Time Choice Plus General Service (Schedule “TP-GS”), and Non-Standard Large General Service (Schedule “NS-LG”) rate classes, yield RORs that are less than the system or overall ROR. The Figure also shows other rate classes, such as the Non-Standard General Service (Schedule “NS-GS”), Time Choice General Service (Schedule “TC-GS”), Time Choice Large General Service (Schedule “TC-LG”), Small Primary General Service (Schedules “NS-SP” and “TC-SP”), Large Power (Schedule “LP”), and Transmission (Schedule “TS”) rate classes, yield RORs that are more than the system or overall ROR. Except as described in this

1 testimony, the COSS was prepared consistent with the methodologies used in the  
2 Company's rebuttal testimony in Case No. ER-2021-0312, the Company's prior rate  
3 case.

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

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

12 The Company prepared a total bill impact analysis to evaluate the impact of the  
13 proposed base rate changes. The total bill impact analysis evaluated a wide range of  
14 customer usage that compares (i) the proposed base rates plus the current Demand-side  
15 Investment Mechanisms Rider ("DSIM"), current Securitized Utility Tariff Charge  
16 ("SUTC"), and current Fuel Adjustment Clause ("FAC") rate to (ii) the current base  
17 rates plus the current Energy Efficiency Cost Recovery ("EECR") charge, current  
18 DSIM charge, current SUTC charge, and current FAC rate.

19 Overall, the proposed base rates will increase monthly bill for a Residential  
20 General customer using 1,000 kWh per month by \$30.84 per month, or 19.15 percent.<sup>1</sup>

---

<sup>1</sup> Based on a monthly bill for a Residential General customer using 1,000 kWh per month, including current EECR of \$0.00028 per kWh, DSIM charge of \$0.00080 per kWh, FAC charge of \$0.00811 per kWh and SUTC charge of \$0.01047.

1 **Q. Please briefly describe the Company’s service area.**

2 A. The Company is a regulated utility providing electric service in parts of Missouri,  
3 Kansas, Oklahoma, and Arkansas. In the Missouri jurisdiction, the Company provides  
4 electric service to residential, commercial and industrial (“C&I”), and street lighting  
5 customers. The Company serves an average of 166,405 electric customers in Missouri,  
6 including 140,994 (84.73 percent) residential customers, 25,063 (15.06 percent) C&I  
7 customers, and 348 (0.21 percent) lighting customers.

8 Customers are presently served under one of 16 rate classes based on type of  
9 service, load characteristics, and customer choice. The rate classes consist of three  
10 residential rate schedules (Non-Standard, Time Choice, and Time Choice Plus) class,  
11 ten C&I classes (Non-Standard, Time Choice, and Time Choice Plus General Service;  
12 Non-Standard and Time Choice Large General Service; Non-Standard and Time  
13 Choice Primary Service; Large Power; Transmission; and Miscellaneous Service), and  
14 three Lighting classes, as shown in Figure 2 (below).

15 **Figure 2: Customers and kWh Sales by Current Rate Classes**

| EDE MO<br>Rate Classes | Number of<br>Customers | % of<br>Customers | Normalized<br>Usage (kWh) | % Usage        | kWh Use per<br>Customer |
|------------------------|------------------------|-------------------|---------------------------|----------------|-------------------------|
| NS-RG                  | 567                    | 0.34%             | 9,067,286                 | 0.21%          | 15,992                  |
| TC-RG                  | 140,353                | 84.34%            | 1,740,855,838             | 41.21%         | 12,403                  |
| TP-RG                  | 74                     | 0.04%             | 919,662                   | 0.02%          | 12,428                  |
| NS-GS                  | 966                    | 0.58%             | 14,305,214                | 0.34%          | 14,809                  |
| TC-GS                  | 21,269                 | 12.78%            | 405,154,003               | 9.59%          | 19,049                  |
| TP-GS                  | 3                      | 0.00%             | 6,234                     | 0.00%          | 2,078                   |
| NS-LG                  | 319                    | 0.19%             | 197,590,621               | 4.68%          | 619,406                 |
| TC-LG                  | 2,403                  | 1.44%             | 852,362,886               | 20.18%         | 354,708                 |
| NS-SP                  | 38                     | 0.02%             | 95,932,609                | 2.27%          | 2,524,542               |
| TC-SP                  | 18                     | 0.01%             | 10,966,305                | 0.26%          | 609,239                 |
| LP                     | 44                     | 0.03%             | 800,548,330               | 18.95%         | 18,125,623              |
| TS                     | 1                      | 0.00%             | 67,932,326                | 1.61%          | 67,932,326              |
| MS                     | 2                      | 0.00%             | 135,540                   | 0.00%          | 65,059                  |
| SPL                    | 7                      | 0.00%             | 16,879,087                | 0.40%          | 2,411,298               |
| PL                     | 219                    | 0.13%             | 11,436,802                | 0.27%          | 52,124                  |
| LS                     | 122                    | 0.07%             | 684,952                   | 0.02%          | 5,637                   |
| <b>Total</b>           | <b>166,405</b>         | <b>100.00%</b>    | <b>4,224,777,695</b>      | <b>100.00%</b> |                         |
| Residential            | 140,994                | 84.73%            | 1,750,842,786             | 41.44%         | 12,418                  |
| General Service        | 25,063                 | 15.06%            | 2,444,934,068             | 57.87%         | 97,551                  |
| Lighting               | 348                    | 0.21%             | 29,000,841                | 0.69%          | 83,356                  |

16

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

2 A. The Company's current base rate structure consists of base rates which reflect a  
3 normalized level of fuel and purchased power costs, and an EECR charge.<sup>2</sup> The base  
4 rates include monthly customer charges, energy (kWh) charges, and demand (kW)  
5 charges. For certain rate classes, the energy charges vary by season and consist of  
6 declining rate steps or blocks; i.e., the rates decrease as monthly consumption increases.  
7 For example, the energy charges for the RG class vary by winter (October through  
8 May) and summer (June through September) seasons. The first 600 kWh of monthly  
9 energy consumption during the winter season (i.e., first rate step or block) is charged a  
10 higher rate than consumption greater than 600 kWh (i.e., second rate step or block).  
11 For certain rate classes, the energy charges vary by time-of-use.

12 **Q. Please describe the Company's rate classes.**

13 A. Figure 2 (above) provides a breakdown of test year customers and kWh sales by rate  
14 class. The test year represents the period October 1, 2022 through September 30, 2023.  
15 The usage in Figure 2 has been normalized for weather.

16 The Figure shows the residential rate class in aggregate represents a majority of  
17 the Company's customers. The Figure also shows variations in annual use per  
18 customer among the rate classes. Residential customers, for example, use on average  
19 12,418 kWh per year, while Large Power customers use on average 18,125,623 kWh  
20 per year.

21 Figure 3 (below) shows monthly kWh usage by rate class. The Figure shows  
22 usage varies seasonally for certain rate classes.

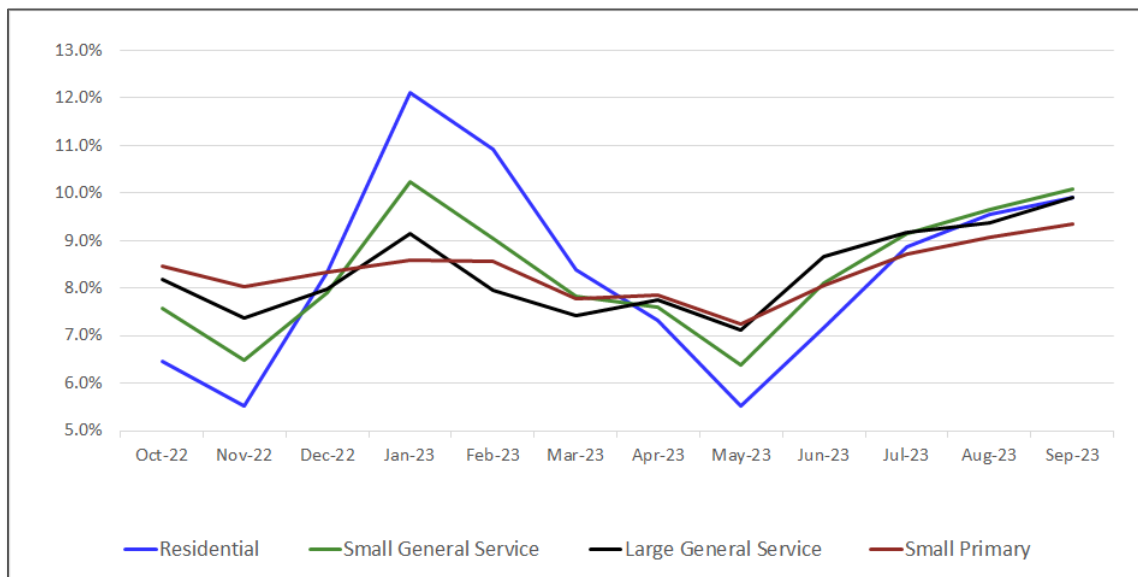
---

<sup>2</sup> The Company's tariffs are available at: <https://central.libertyutilities.com/all/residential/rates/mo-electric-rates.html>.



1

**Figure 3: Monthly kWh Usage as % of Annual Usage**



2

3 The Figure shows the residential class, for example, demonstrates a seasonal load  
4 pattern, with monthly sales increasing during the winter and summer months, reflecting  
5 heating and cooling use, respectively. The C&I rate classes show relatively consistent  
6 load patterns throughout the year, with slight increases during the winter and summer  
7 months. The load pattern differences, as discussed below, have implications on the  
8 allocation of costs in the COSS.

9 **III. REVENUE ADJUSTMENTS**

10 **Q. What is the purpose of the revenue adjustments?**

11 A. The purpose of the revenue adjustments is to adjust test year revenues to reflect a  
12 normalized level of revenue in a given year utilizing current approved retail rates.

13 **Q. What are the proposed revenue adjustments?**

14 A. The Company proposes three revenue adjustments: (1) weather normalization  
15 adjustment, (2) customer annualization adjustment, and (3) load growth/loss  
16 adjustment.

1 **Q. What was the approach to derive the weather normalization adjustment?**

2 A. The approach to derive the weather normalization adjustment consisted of (1) utilizing  
3 the weather normalization sales kWh adjustment prepared by Company witness Fox,  
4 (2) apportioning the weather normalization sales kWh adjustment to each billing  
5 determinant to reflect the impact of colder and warmer than normal weather, (3)  
6 adjusting the kW demands to reflect the impact of colder and warmer than normal  
7 weather, and (4) applying the current base rates to the weather normalization sales kWh  
8 adjustments and kW demand adjustments

9 **Q. What was the approach to derive the customer annualization adjustment?**

10 A. The approach to derive the customer annualization adjustment consisted of (1)  
11 identifying new customers added during the test year and annualizing their revenues  
12 based on class average revenues per customer per month, and (2) identifying existing  
13 customers who switched rate classes during the test year and assigning their revenues  
14 to the new rate class based on each customer's revenue per month.

15 **Q. What was the approach to derive the load growth/loss adjustment?**

16 A. The approach to derive the load growth/ loss adjustment consisted of (1) identifying  
17 significant changes in kWh usage among three Large Power customers during the test  
18 year, (2) annualizing the usage to reflect a full year at the new kWh usage, and (3)  
19 calculating the difference in revenues between the actual kWh usage and annualized  
20 kWh usage.

21 **Q. What were the net results of the revenue adjustment process?**

22 A. The net results of the revenue adjustment process yielded an increase in class revenues  
23 of \$848,291, as shown in Figure 4 (below).

1

**Figure 4: Summary of Revenue Adjustments**

| 12 ME Sep'23<br>Total Revenue | Adjustments        |                  |                     | Normalized<br>Revenues |                    |
|-------------------------------|--------------------|------------------|---------------------|------------------------|--------------------|
|                               | Actual Revenues    | Weather Norm.    | Cust. Annualization |                        | Load Growth        |
| NS RG-Residential             | 26,588,837         | 101,910          | (25,360,937)        | 1,329,809              |                    |
| TC RG-Residential             | 215,087,792        | 1,706,452        | 25,838,849          | 242,633,092            |                    |
| TP RG-Residential             | 91,960             | 678              | 32,478              | 125,116                |                    |
| NS GS-General                 | 9,135,734          | 31,804           | (7,052,284)         | 2,115,255              |                    |
| TC GS-General                 | 50,420,084         | 73,438           | 7,524,727           | 58,018,249             |                    |
| TP GS-General                 | 763                | (27)             | 899                 | 1,635                  |                    |
| LG-Large General              | 42,313,075         | (4,913)          | (21,605,462)        | 20,702,699             |                    |
| TC LG-Large General           | 71,746,451         | (210,403)        | 21,538,223          | 93,074,270             |                    |
| SP-Small Primary              | 9,857,806          | (9,247)          | (303,827)           | 9,544,732              |                    |
| TC SP-Small Primary           | 954,652            | (649)            | 248,375             | 1,202,378              |                    |
| LP-Large Power                | 69,891,347         | -                | -                   | (1,701,792)            | 68,189,555         |
| TS-Transmission               | 4,294,509          | -                | -                   | -                      | 4,294,509          |
| MS-Miscellaneous              | 14,995             | -                | -                   | -                      | 14,995             |
| SPL-Municipal St Lighting     | 2,306,516          | -                | -                   | -                      | 2,306,516          |
| PL-Private Lighting           | 4,184,760          | -                | -                   | -                      | 4,184,760          |
| LS-Special Lighting           | 127,321            | -                | -                   | -                      | 127,321            |
| <b>Total</b>                  | <b>507,016,602</b> | <b>1,689,042</b> | <b>861,041</b>      | <b>(1,701,792)</b>     | <b>507,864,892</b> |

2

3 **IV. ALLOCATED COST OF SERVICE STUDY**

4 **Q. Please describe the purpose of a COSS.**

5 A. The purpose of a COSS is to allocate a utility's overall cost of service to each rate class  
6 in a manner that reflects its underlying cost of service. The COSS sponsored in this  
7 testimony was developed by identifying the relationship between the service  
8 requirements for each rate class and their respective cost drivers. This approach is well  
9 established in industry literature.<sup>3</sup>

10 **Q. Please describe the approach used to develop the COSS for this case.**

11 A. The approach to develop the COSS in this rate case filing was based on three steps.  
12 First, costs were functionalized or assigned into functional categories. Next,  
13 functionalized costs were classified into one of three cost drivers, based on whether the  
14 costs are related to: (1) serving peak demands, (2) serving energy demands, or (3)  
15 meeting customer service requirements. Finally, classified costs were allocated to each  
16 rate class based on methods that best reflect how the costs were incurred.

<sup>3</sup> See Principles of Public Utility Rates by James C. Bonbright.

1           The three steps were performed using two types of assignments: direct  
2 assignment and indirect assignment. Direct assignments utilized the Company's  
3 financial and plant records to assign plant investments and expenses to specific  
4 functions, classifications, and rate classes. Indirect assignments utilized composite  
5 allocators based on direct and indirect assignments developed during the  
6 functionalization, classification, and allocation process.

7           The functionalization, classification, and allocation of costs is included in  
8 **Direct Schedule TSL-3.**

9 **Q. What is functionalization?**

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

13 **Q. How were costs functionalized in the COSS?**

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

1 **Q. What is classification?**

2 A. Classification is the process of assigning rate base and expense items into categories  
3 that reflect cost-causation. There are three principle causes or drivers of costs related  
4 to the electric system:

5 Customer-related – costs that vary with the number of customers, such as costs  
6 associated with connecting customers to the electric system and providing basic  
7 customer services, such as billing.

8 Demand-related – costs that vary with maximum customer demands at the time  
9 of the system peak, at the time of the rate class peak, or at the time of the  
10 customer peak.

11 Energy-related – costs that vary with the production, transmission, and delivery  
12 of energy, such as fuel and purchased power expenses.

13 **Q. What is allocation?**

14 A. Allocation is the process of assigning rate base and expense items to each rate class  
15 based on allocators that best reflect how the costs were incurred. In other words, cost  
16 allocation should follow how costs were incurred.

17 **Q. What types of allocators were used to develop the COSS?**

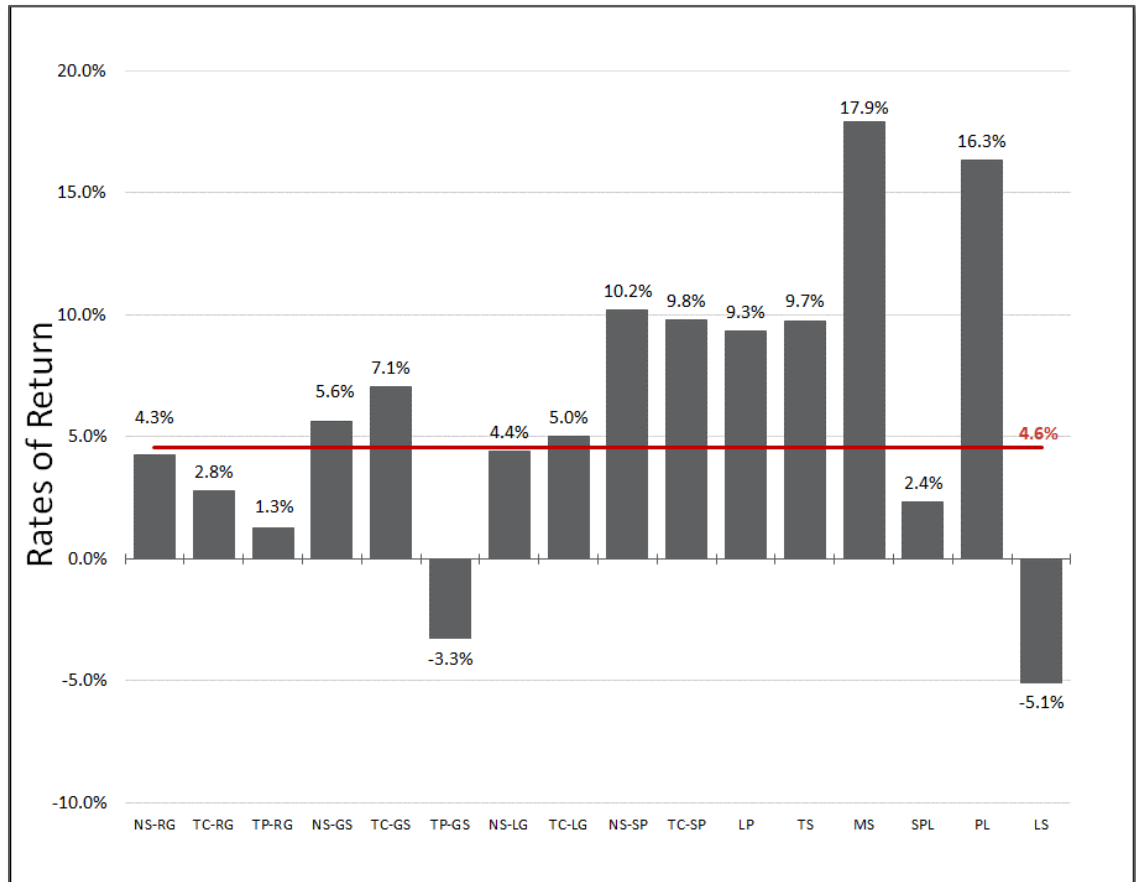
18 A. Three types of allocators were used to develop the COSS:

- 19 1. Class determinants – class characteristics, such as number of customers, peak  
20 demands, annual usage, and revenues by rate class;
- 21 2. Special studies – detailed analysis of specific plant or expense items, such as  
22 meters and services; and
- 23 3. Indirect – composite allocators based on how other costs were allocated.

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

2 A. The results of the COSS are shown in Figure 1 (replicated below for ease of reference).  
3 The Figure compares the calculated ROR for each rate class (based on current rates) to  
4 the system or overall ROR (based on current rates).

5 **Figure 4: COSS Results (Replicated)**



6  
7 The Figure shows certain rate classes yield RORs that are less than the system or overall  
8 ROR, while others yield RORs that are more than the system or overall ROR.

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

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

1

**Figure 5: Unit Cost of Service by Rate Class<sup>4</sup>**

| Rate Class | Class Revenue Requirements |            |
|------------|----------------------------|------------|
|            | \$ per Customer            | \$ per kWh |
| NS-RG      | \$ 2,812                   | \$ 0.18    |
| TC-RG      | \$ 2,298                   | \$ 0.19    |
| TP-RG      | \$ 2,585                   | \$ 0.21    |
| NS-GS      | \$ 2,408                   | \$ 0.16    |
| TC-GS      | \$ 2,761                   | \$ 0.14    |
| TP-GS      | \$ 1,122                   | \$ 0.54    |
| NS-LG      | \$ 78,203                  | \$ 0.13    |
| TC-LG      | \$ 44,807                  | \$ 0.13    |
| NS-SP      | \$ 213,861                 | \$ 0.08    |
| TC-SP      | \$ 56,553                  | \$ 0.09    |
| LP         | \$ 1,387,033               | \$ 0.08    |
| TS         | \$ 4,205,829               | \$ 0.06    |
| MS         | \$ 4,599                   | \$ 0.07    |
| SPL        | \$ 580,830                 | \$ 0.24    |
| PL         | \$ 13,023                  | \$ 0.25    |
| LS         | \$ 4,195                   | \$ 0.74    |

2

3 The Figure shows, for example, the unit cost of service for Schedule TC-RG is \$2,298  
 4 per customer, while the unit cost of service for Schedule LP is \$1,387,033 per customer.  
 5 By comparison, the unit cost of service for Schedule TC-RG is \$0.19 per kWh, while  
 6 the unit cost of service for Schedule LP is \$0.08 per kWh.

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

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

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

13 A. If a rate class yields a ROR that is lower than the system ROR (assuming the system  
 14 ROR achieves full cost of service recovery), then the revenues recovered from the rate

<sup>4</sup> For confidentiality purpose, TS rate class average cost of service is not shown in this testimony.

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

7 **Q. Please describe the data used to prepare the COSS.**

8 A. The COSS study was based on test year data for the period October 1, 2022 through  
9 September 30, 2023. The COSS includes the number of customers, sales, and revenues  
10 by rate class. Sales and revenues have been adjusted to reflect the impact of normal  
11 weather, annualization of customers switching among rate class, and customer, sales,  
12 and revenue growth/ loss.

13 The COSS also includes rate base items, including intangible plant, production,  
14 transmission, distribution, and general plant-in-service, as well as (a) additions to plant-  
15 in-service, including materials and supplies, prepayments, cash working capital, and  
16 other regulatory assets, and (b) reductions to plant-in-service, including accumulated  
17 deferred income taxes ("ADIT"), customer deposits, customer advances for  
18 construction, and other regulatory liabilities. The COSS also includes operations and  
19 maintenance ("O&M") expenses, including transmission, distribution, customer  
20 service, customer account, sales, administrative and general expenses, income taxes,  
21 and taxes other than income taxes, such as payroll and property taxes.

22 **Q. Please describe the functionalization process used in developing the COSS.**

23 A. As discussed earlier, functionalization is an important first step in development of the  
24 COSS study. The functionalization process in this study generally followed the USOA.



1           However, distribution plant was further functionalized into primary and secondary  
2           distribution facilities to ensure that the cost of service at these functional levels was  
3           separately identified and applied.

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

- 5           • Production – plant investment and expenses associated with the Company’s  
6           generation facilities. These include production plant, accumulated  
7           depreciation, depreciation expense, and production expenses.
- 8           • Transmission – plant investment and expenses associated with the Company’s  
9           high voltage transmission facilities. These include transmission plant,  
10          accumulated depreciation, depreciation expense, and related O&M expenses.
- 11          • Primary Distribution – plant investment and expenses associated with the  
12          Company’s primary voltage distribution facilities. These include primary  
13          distribution plant, accumulated depreciation, depreciation expense, and related  
14          O&M expenses. Some costs that support both the primary and secondary  
15          distribution systems were functionalized into primary and secondary functions.  
16          Such costs include poles and towers, overhead conductors and devices,  
17          underground conduit, and underground conductors and devices.
- 18          • Secondary Distribution – plant investment and expenses associated with the  
19          Company’s secondary voltage distribution facilities. These include secondary  
20          distribution plant, accumulated depreciation, depreciation expense, and related  
21          O&M expenses. The secondary portion of poles and towers, overhead  
22          conductors and devices, underground conduit, and underground conductors  
23          and devices are also included in this function.

1           • Customer Service – expenses associated with providing customer service.  
2           These costs are largely related to customer service, customer accounts, and  
3           sales expenses.

4           The remaining rate base and cost of service accounts were assigned to one of  
5           five functional categories based on composite functionalization of the plant accounts.  
6           For example, general plant and labor-related administrative and general (“A&G”)  
7           expenses were assigned to all five functional categories based on the composite  
8           functionalization of labor-related production, transmission, distribution, and customer  
9           service expenses.

10           The functionalization of costs is included in **Direct Schedule TSL-3**.

11   **Q. Please describe the classification process used in developing the COSS study.**

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

- 13           • Customer – costs associated with providing customer access to the electric  
14           system as well as providing on-going customer service, such as billing services.  
15           • Demand – costs associated with meeting customer peak demand requirements.  
16           • Energy – costs associated with meeting customer energy requirements.

17           In some cases, costs were classified into only one of three categories. The cost of  
18           billing services, for example, was classified as customer. In other cases, costs were  
19           classified into more than one category. For example, the cost associated with primary  
20           distribution plant was classified based on its underlying characteristics. Some costs  
21           were classified as customer, while others were classified as demand.

22   **Q. Please explain the classification of distribution facilities.**

23   A. Distribution plant represents 33.70 percent of the Company’s investment in utility  
24           plant. The classification of distribution plant reflects two primary cost drivers. The

1 first cost driver is the number of customers, i.e., distribution facilities are designed to  
2 provide customer access to the electric system. The second cost driver is peak  
3 demands, i.e., distribution facilities are designed to meet customer peak demands  
4 throughout the year. The approach to classification of distribution facilities is well-  
5 established and recognized by the National Association of Regulatory Commissioners  
6 (“NARUC”). Specifically, NARUC states:

7 Distribution plant accounts 364 through 370 involve demand and  
8 customer costs. The customer component of distribution facilities is  
9 that portion of costs which varies with the number of customers. Thus,  
10 the number of poles, conductors, transformers, services and meters are  
11 directly related to the number of customers on the utility’s  
12 system...each primary plant account can be separately classified into  
13 demand and customer components.<sup>5</sup>  
14

15 The classification of distribution plant in this study is consistent with the approach  
16 described in the NARUC manual as well as the approach described in the Company’s  
17 prior rate case filing in Case No. ER-2021-0312. As discussed earlier, distribution plant  
18 and related costs were separated into two functions: primary and secondary  
19 distribution. The primary distribution facilities and line transformers were classified as  
20 customer- or demand-related, while Secondary distribution facilities were generally  
21 classified as customer-related.

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

23 A. Distribution plant accounts were classified based on their specific functions. For  
24 distribution plant related to facilities associated with distribution substations (Accounts  
25 360-363), the plant was classified as demand and allocated to each rate class based on  
26 class Non-Coincident Peak (“NCP”) demands. Substations generally reflect the peak  
27 demands of customers served from the substation and thus can peak at times different

---

<sup>5</sup> NARUC Electric Utility Cost Allocation Manual, p. 90.

1 than the system peak. The class NCP reflects peak demands of customers served from  
2 the substations.

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

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

10 A. There are two methods recognized in the NARUC manual for classifying Accounts  
11 364-368 costs between customer and demand: the ‘minimum-size’ and ‘zero-intercept’  
12 methods.

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

20 Classifying distribution plant with the minimum-size method assumes  
21 that a minimum size distribution system can be built to serve the  
22 minimum loading requirements of the customer. The minimum-size  
23 method involves determining the minimum size pole, conductor, cable,  
24 transformer, and service that is currently installed by the utility.<sup>6</sup>  
25

---

<sup>6</sup> NARUC Electric Utility Cost Allocation Manual, p. 90.

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

9 The minimum-intercept method seeks to identify that portion of plant  
10 related to a hypothetical no-load or zero-intercept situation....The  
11 technique is related to installed cost to current carrying capacity or  
12 demand rating, creating a curve for various sizes of the equipment  
13 involved, using regression techniques, and extend the curve to a no-load  
14 intercept. The cost related to the zero-intercept is the customer  
15 component.<sup>7</sup>  
16

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

19 A. The Company classified distribution plant for Accounts 365, 367 and 368 based on  
20 using the minimum-size method and for Accounts 364 and 366 based on using the zero-  
21 intercept methods. The minimum-size and zero-intercept methods utilized the  
22 Company’s installed costs for each plant account adjusted for current dollars utilizing  
23 the Handy-Whitman Index of Public Utility Construction Costs (“Handy-Whitman”).

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

25 A. The results of the studies are provided in Direct Schedule TSL-3.

- 26 • Poles, Towers, and Fixtures (Account 364): The Company’s minimum-size and  
27 zero-intercept studies for Account 364 resulted in, respectively, 44.7 percent

---

<sup>7</sup> Id. at p. 92.

1 and 39.3 percent of costs classified as customer-related. Since both methods  
2 are recognized by NARUC, the Company used the lower of the two results for  
3 use in the COSS study, i.e., 39.3 percent of costs are classified as customer-  
4 related with the remaining portion classified as demand-related.

5 • Overhead conductors and devices (Account 365): The Company's minimum-  
6 size study for Account 365 resulted in 35.5 percent of costs classified as  
7 customer-related with the remaining portion as demand-related.

8 • Underground Conduits (Accounts 366): The Company's minimum-size and  
9 zero-intercept studies for Account 366 resulted in, respectively, 54.3 percent  
10 and 46.1 percent of costs classified as customer-related. Since both methods are  
11 recognized by NARUC, the Company used the lower of the two results for use  
12 in the COSS study, i.e., 46.1 percent of costs are classified as customer-related  
13 with the remaining portion classified as demand-related.

14 • Underground Conductors and Devices (Accounts 367): The Company's  
15 minimum-size study for Account 367 resulted in 39.6 percent of costs classified  
16 as customer-related with the remaining portion as demand-related.

17 • Line Transformers (Account 368): The Company's minimum size study  
18 resulted in 45.6 percent of costs classified as customer-related with the  
19 remaining portion classified as demand-related.

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

21 A. Other rate base items were similarly classified based on their underlying cost drivers.  
22 For example, meter cost, meter installation and service cost investments were classified  
23 as customer-related since they enable customers access to the electric system. Rate  
24 base items which are not directly associated with one of the classification categories,

1 such as intangible plant, were classified using a composite classifier based on the  
2 classification of total plant.

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

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

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

10 **Q. Please describe the allocation process used in developing the COSS study.**

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

14 **Q. Please describe the allocators used in developing the COSS.**

15 A. The COSS was based on three types of allocators:

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

21 The allocation of costs is included in Direct Schedule TSL-3.

22 **Q. What methodology was used to allocate production plant costs?**

1 A. The methodology to allocate production plant costs was the Average and Excess  
2 (“A&E”) 8NCP method. The method is consistent with the Company’s approach to  
3 designing and building production facilities.

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

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

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

14 The second component of the A&E allocator is excess demand, which  
15 represents the peak demand portion of production plant. It represents each rate class’s  
16 share of the peak demand – i.e., the demand in excess of the average demand. This  
17 component is calculated as each rate class’s share of the excess demand – or the  
18 difference between the class peak demand and the class average demand. The rate class  
19 peak demand is based on NCP demands, consistent with the methodology described in  
20 the NARUC Manual.<sup>8</sup> The approach to calculate the A&E allocator in the Company’s  
21 class cost of service study followed the methodology described in the NARUC Manual,  
22 which utilizes NCP demands rather than Coincident Peak (“CP”) demands.<sup>9</sup> The

---

<sup>8</sup> NARUC Electric Utility Cost Allocation Manual, pp. 49-52.

<sup>9</sup> Id. at p. 50.



1 NARUC Manual points out that it is a “mistake” to use CP demands instead of NCP  
2 demands since it produces an allocator that is equivalent to a CP allocator.<sup>10</sup> Thus,  
3 using the CP demands approach is contrary to the purpose of the A&E allocator since  
4 the A&E allocator is designed to allocate costs based on peak and average demands.  
5 The excess demand component is weighted by the remaining portion of production  
6 plant – i.e., by 1 minus the system load factor – and then added to the average demand  
7 component to derive the A&E allocator.

8 The NCP demands were based on an average of four months of winter  
9 (December through March) and four months of summer (June through September).  
10 The method is consistent with the Company’s planning requirements, which are based  
11 on the Southwest Power Pool’s (“SPP”) resource adequacy requirements in the summer  
12 and winter periods. The summer requirements are based on peak loads and reserve  
13 margins in June through September, while the winter requirements are based on peak  
14 loads and reserve margins in December through March.

15 The A&E allocators were developed utilizing average demand (kWh), and CP  
16 and NCP demand data gathered by the Company for each customer class through its  
17 AMI meter reading data. The CP demand represents class demand at the time of the  
18 system peak, while NCP represents aggregate customer peak demand.

19 Derivation of the A&E allocator is included in **Direct Schedule TSL-3**.

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

21 A. Figure 6 (below) shows the results of the A&E method.

---

<sup>10</sup> 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.”

1

**Figure 6: Results of A&E Method**

| Average and Excess (8 NCP) |                              |                           |                          |                          |                         |                         |
|----------------------------|------------------------------|---------------------------|--------------------------|--------------------------|-------------------------|-------------------------|
| Rate Class                 | Peak Demand<br>8 NCP<br>(MW) | Average<br>Demand<br>(MW) | Excess<br>Demand<br>(MW) | Average<br>Demand<br>(%) | Excess<br>Demand<br>(%) | A&E<br>Allocator<br>(%) |
| NS Residential             | 2,703                        | 1,121                     | 1,582                    | 0.22%                    | 0.32%                   | 0.27%                   |
| TC Residential             | 507,978                      | 215,302                   | 292,676                  | 41.42%                   | 58.41%                  | 50.61%                  |
| TP Residential             | 283                          | 114                       | 170                      | 0.02%                    | 0.03%                   | 0.03%                   |
| NS General Service         | 3,681                        | 1,769                     | 1,912                    | 0.34%                    | 0.38%                   | 0.36%                   |
| TC General Service         | 96,702                       | 50,108                    | 46,594                   | 9.64%                    | 9.30%                   | 9.46%                   |
| TP General Service         | 3                            | 1                         | 2                        | 0.00%                    | 0.00%                   | 0.00%                   |
| NS Large General           | 48,924                       | 24,437                    | 24,487                   | 4.70%                    | 4.89%                   | 4.80%                   |
| TC Large General           | 198,142                      | 105,417                   | 92,725                   | 20.28%                   | 18.50%                  | 19.32%                  |
| NS Small Primary           | 18,065                       | 11,576                    | 6,489                    | 2.23%                    | 1.29%                   | 1.72%                   |
| TC Small Primary           | 2,521                        | 1,323                     | 1,198                    | 0.25%                    | 0.24%                   | 0.25%                   |
| Large Power                | 124,676                      | 96,887                    | 27,789                   | 18.64%                   | 5.55%                   | 11.56%                  |
| Transmission               | 8,451                        | 8,111                     | 340                      | 1.56%                    | 0.07%                   | 0.75%                   |
| MS-Miscellaneous           | 17                           | 17                        | 0                        | 0.00%                    | 0.00%                   | 0.00%                   |
| SPL-Municipal St Lighting  | 4,658                        | 2,088                     | 2,570                    | 0.40%                    | 0.51%                   | 0.46%                   |
| PL-Private Lighting        | 3,227                        | 1,414                     | 1,813                    | 0.27%                    | 0.36%                   | 0.32%                   |
| LS-Special Lighting        | 847                          | 85                        | 762                      | 0.02%                    | 0.15%                   | 0.09%                   |
| <b>Total</b>               | <b>1,020,879</b>             | <b>519,770</b>            | <b>501,109</b>           | <b>100.00%</b>           | <b>100.00%</b>          | <b>100.00%</b>          |

2

3 The Figure shows the results of the A&E method, including the average demand and  
 4 excess demand components for each rate class, weighted by the system load factor.  
 5 The Figure shows that the TC-RG rate class allocator is 50.61 percent based on the  
 6 A&E method, representing a composite of their average demand of 41.42 percent and  
 7 their peak (in excess of average) demand of 58.41 percent.

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

11 **Q. What was the method to allocate transmission plant?**

12 A. Transmission plant represents 16.50 percent of the Company's utility plant.  
 13 Transmission costs are incurred consistent with the design of the Company's  
 14 transmission facilities to meet system capacity requirements. Transmission plant is  
 15 designed to meet peak demands throughout the year since monthly peak demands are  
 16 within a relatively narrow range and transmission capacity must be ready throughout

1 the year to move generation output on and off the system when dispatched for SPP.  
2 Thus, transmission plant is allocated based on 12-month average coincident peak  
3 (“12CP”). The 12CP allocator is recognized by NARUC as a reasonable transmission  
4 cost allocator,<sup>11</sup> and it is consistent with the methodologies utilized in the Company’s  
5 prior rate case filing.

6 **Q. What was the method to allocate distribution plant costs?**

7 A. Distribution costs are incurred consistent with the design of the Company’s distribution  
8 facilities to provide customer access to the electric system (customer-related) and to  
9 meet customer peak demands throughout the year (demand-related).

10 The Company allocated the demand portion of distribution costs based on the  
11 INCP method. The method reflects that the distribution plant is designed to meet  
12 customer peak demands.

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

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

16 • Meter investments were allocated based on the current cost of meters in each  
17 rate class. The allocator reflects the Company’s estimated cost of meter and  
18 meter installation for each rate class.

19 • Service investments were allocated based on the current cost of services in each  
20 rate class. The allocator reflects the Company’s estimated cost of service line  
21 and installation for each customer class.

22 • Line transformers were allocated based on number of customers for each  
23 customer class. The number of customers were weighted to reflect the average

---

<sup>11</sup> NARUC Electric Utility Cost Allocation Manual, p. 79.

1 number of customers by rate class served by a single transformer. The allocator  
2 recognizes that transformers are built to address varying customer demands and  
3 may serve multiple customers within a rate class depending on the demand (e.g.,  
4 a single transformer serves approximately 2.7 RG customers per Company  
5 estimates).

6 The approach to prepare the special studies is consistent with the methodologies  
7 utilized in the Company's prior rate case filing.

8 Derivation of the meter and services allocators is included in **Direct Schedule**  
9 **TSL-3**.

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

11 A. There are several composite allocators developed internally based on the allocation of  
12 various plant investments and expenses. These are used to allocate cost items that  
13 cannot be readily categorized. For example, general plant is allocated based on the  
14 composite allocation of all labor-related production, transmission, distribution,  
15 customer accounts, and customer service O&M expenses. This approach is well  
16 established in industry literature,<sup>12</sup> and it is consistent with the methodologies utilized  
17 in the Company's prior rate case filing.

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

19 A. O&M expenses were allocated generally consistent with their respective plant  
20 accounts. For example, fixed production O&M expenses were allocated using the A&E  
21 Method. Similarly, the allocation of distribution O&M expenses followed the  
22 allocation of their respective plant account.

---

<sup>12</sup> NARUC Electric Utility Cost Allocation Manual, p. 105.

1 **V. OVERVIEW OF RATE DESIGN**

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

3 A. The proposed rate design was guided by several principles commonly used throughout  
4 the industry, including: (a) rates should recover the overall cost of providing service;  
5 (b) rates should be fair, minimizing inter- and intra-class inequities to the extent  
6 possible; and (c) rate changes should be tempered by rate continuity concerns.<sup>13</sup>

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

9 **Q. How were these principles applied in this proceeding?**

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

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

---

<sup>13</sup> See Bonbright, James, Danielsen, Albert, and Kamerschen, David. "Principles of Public Utility Rates." Public Utilities Reports, Inc. pp. 377-407 (2<sup>nd</sup> Ed. 1988).

1 A. The first step to develop the proposed rates was to establish the overall revenue  
2 requirement to be recovered by base rates. The next step was to set revenue targets for  
3 each rate class based on the results of the COSS, as shown on **Direct Schedule TSL-**  
4 **4**. Rates within each rate class were then designed to recover the revenue targets based  
5 on test year customer, kW demand, and kWh usage data.

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

7 A. To determine the total revenue requirement, I relied on the overall cost of service  
8 presented in the testimony and accounting schedules of Company witness Charlotte T.  
9 Emery, which indicates a total revenue requirement of \$668.4 million. The total  
10 revenue requirement was then reduced by revenues other than base rates to calculate  
11 base rate revenue requirements.

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

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

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

18 A. The proposed rates were designed by first ensuring the rates recover the proposed  
19 revenue target for each rate class. The proposed rates were then designed by reviewing  
20 the customer charge to evaluate what level of fixed cost is reasonable to be recovered  
21 through the proposed customer charges, consistent with rate design objectives  
22 described above. Once the proposed customer charges were established, the remaining  
23 revenue target for each class was recovered via kWh sales charges, and for certain rate  
24 classes kW demand charges, as shown in **Direct Schedule TSL-5**.

1 **VI. RATE DESIGN AND BILL IMPACT ANALYSES**

2 **Q. What was the process to derive class revenue targets for each rate class.**

3 A. To mitigate bill impact concerns, the proposed class revenue targets for each rate class  
4 were based on a 10.0 percent movement toward Equalized Rates of Return (“EROR”),  
5 as shown in **Direct Schedule TSL-4**.

6 Specifically, **Direct Schedule TSL-4** shows revenue requirements for each rate  
7 class based on their cost of service with full movement to EROR. The percentage  
8 increase in revenues for the Residential TC-RG class with full movement to EROR is  
9 29.60 percent, or 1.85 times the overall percentage increase in revenues. The Figure  
10 also shows revenue requirements for each rate class based on a uniform increase in  
11 revenues with no movement toward EROR. The revenue increase for the Residential  
12 class is 16.00 percent, consistent with the overall revenue increase.

13 However, the Company believes a 10.0 percent movement to EROR strikes an  
14 appropriate balance between moving to cost-based rates (full movement to EROR) and  
15 addressing rate continuity considerations (uniform increase in revenues).

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

17 A. The proposed revenue requirement targets for each class are presented in Figure 7  
18 (below).

1

**Figure 7: Target Revenues**

| Rate Class             | Proposed Revenues     | Current Revenues      | Increase \$          | Increase %   |
|------------------------|-----------------------|-----------------------|----------------------|--------------|
| NS-RG Residential      | \$ 1,701,898          | \$ 1,464,585          | \$ 237,313           | 16.2%        |
| TC-RG Residential      | 317,015,660           | 270,137,974           | 46,877,686           | 17.4%        |
| TP-Residential         | 166,347               | 139,625               | 26,721               | 19.1%        |
| NS-GS General Service  | 2,681,891             | 2,325,993             | 355,898              | 15.3%        |
| TC-GS General Service  | 73,772,061            | 64,426,224            | 9,345,837            | 14.5%        |
| TC-GS General Service  | 2,138                 | 1,718                 | 420                  | 24.5%        |
| NS-LG Large General    | 27,486,414            | 23,656,046            | 3,830,368            | 16.2%        |
| TC-LG Large General    | 123,033,855           | 106,273,833           | 16,760,023           | 15.8%        |
| NS-SP Small Primary    | 12,888,356            | 11,390,402            | 1,497,955            | 13.2%        |
| TC-SP Small Primary    | 1,791,735             | 1,582,377             | 209,358              | 13.2%        |
| LP-Large Power         | 91,505,724            | 80,596,257            | 10,909,467           | 13.5%        |
| TS-Transmission        | 6,852,609             | 6,030,270             | 822,339              | 13.6%        |
| SPL-Municipal Lighting | 18,975                | 17,061                | 1,914                | 11.2%        |
| MS-Miscellaneous       | 4,371,783             | 3,667,864             | 703,918              | 19.2%        |
| PL-Private Lighting    | 4,890,737             | 4,391,404             | 499,333              | 11.4%        |
| LS-Special Lighting    | 195,705               | 137,633               | 58,072               | 42.2%        |
| <b>Total Company</b>   | <b>\$ 668,375,888</b> | <b>\$ 576,239,264</b> | <b>\$ 92,136,624</b> | <b>16.0%</b> |

2

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

4 A. The proposed residential rates were based on a revenue requirement of \$291.3 million,  
5 which represents an increase of \$47.3 million, or 19.40 percent. The proposed rates  
6 were based on 1.7 million residential bills and 1.7 million MWH in residential sales.

7 The proposed customer charge of \$16.00 per month is well below the  
8 underlying cost of service, as shown in **Direct Schedule TSL-5**. The Schedule shows  
9 basic customer-related costs of \$33.50 per customer per month and fully loaded  
10 customer-related costs of \$48.59. The Company proposes an increase to the customer  
11 charge as a step towards full recovery of the Company's fixed costs in the fixed charge  
12 component. The increase in customer charge has two benefits: (1) it helps mitigate a  
13 basic misalignment between the structure of utility rates and the structure of utility  
14 costs; and (2) it helps minimize intra-class subsidies.

15 The revenue requirement not recovered through the customer charge is  
16 recovered from winter volumetric charges of \$0.18275 per kWh for the first 600 kWh



1 of usage and \$0.12273 per kWh for all additional usage and summer volumetric charges  
2 of \$0.18275 per kWh for the first 600 kWh of usage and \$0.14780 per kWh for all  
3 additional usage. The proposed volumetric charges for the first 600 kWh of usage  
4 reflect customer costs not recovered in the proposed customer charge. The proposed  
5 TC-RG rate design maintains the current Off-Peak kWh credit of \$0.02000 for usage  
6 during the Off-Peak period between 10:00 PM and 6:00 AM. The proposed rate design  
7 and bill impact analyses are included in **Direct Schedule TSL-5**.

8 Overall, the proposed base rates will increase monthly bill for a Residential  
9 General customer using 1,000 kWh per month by \$30.84 per month, or 19.15 percent.<sup>14</sup>

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

11 A. The proposed rates for C&I and Lighting rate classes are developed based on the  
12 revenue targets presented in Figure 7 (above). The proposed revenue targets, billing  
13 determinants, rate design and bill impact analyses are included in **Direct Schedule**  
14 **TSL-5**.

15 **Q. Is the Company proposing any new lamp charges in the lighting schedules?**

16 A. Yes. The Company is proposing to add an additional 4,000 to 5,000 lumens LED lamp  
17 size as part of Private Lighting Service (“Schedule PL”).

18 **Q. Does the proposed rate design for C&I customers reflect seasonal demand**  
19 **charges?**

20 A. Yes. As shown in **Direct Schedule TSL-5**, the proposed rate design for the LG and  
21 LP rate cases reflects seasonal demand charges.

---

<sup>14</sup> Based on a monthly bill for a Residential General customer using 1,000 kWh per month, including current EECR charge of \$0.00028 per kWh, DSIM charge of \$0.00080 per kWh, FSC charge of \$0.00811 per kWh, and SUTC charge of \$0.01047.

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

3 A. Yes. As shown in **Direct Schedule TSL-5**, the Company prepared a total bill impact  
4 analysis to evaluate the impact of the proposed base rate changes. The total bill impact  
5 analysis evaluated a wide range of customer usage that compares (i) the proposed base  
6 rates plus the current DSIM, current SUTC, current FAC rate to (ii) the current base  
7 rates plus the current EECR charge, current DSIM charge, current SUTC charge and  
8 current FAC rate.

9 **Q. What is the annual bill impact for residential and commercial customers?**

10 A. Figure 8 (below) shows the annual bill impact for the residential and commercial  
11 customer classes.

12 **Figure 8: Bill Impact Analysis**

| The Empire District Electric Company<br>Schedule 3, Page 1 of 1<br>4 CSR 240-3.030(3)(B)(3)(4)(5) |                              |                             |                  |                        |                    |
|---|------------------------------|-----------------------------|------------------|------------------------|--------------------|
| Customer Classes  | Average<br>Customer<br>Count | Average Customer Impact [1] |                  | Aggregate Class Impact |                    |
|   |                              | Bill<br>Change \$           | Bill<br>Change % | Annual<br>Change \$    | Annual<br>Change % |
| Residential (NS-RG, TC-RG, TP-RG)   | 140,994                      | 332                         | 16.8%            | 46,839,063             | 16.8%              |
| General Service (NS-GS, TC-GS, TP-GS)   | 22,238                       | 433                         | 14.1%            | 9,620,885              | 14.1%              |
| Large General (NS-LG, TC-LG)  | 2,722                        | 7,489                       | 15.2%            | 20,385,290             | 15.2%              |
| Small Primary (NS-SP, TC-SP)  | 56                           | 30,083                      | 13.1%            | 1,684,637              | 13.1%              |
| LP-Large Power  | 44                           | 242,896                     | 12.8%            | 10,727,906             | 12.8%              |
| TS-Transmission   | 1                            | 437,606                     | 7.3%             | 437,606                | 7.3%               |
| MS-Miscellaneous  | 2                            | 921                         | 12.8%            | 1,920                  | 12.8%              |
| SPL-Municipal St Lighting   | 7                            | 100,803                     | 30.6%            | 705,620                | 30.6%              |
| PL-Private Lighting   | 219                          | 2,281                       | 12.0%            | 500,514                | 12.0%              |
| LS-Special Lighting   | 122                          | 481                         | 46.0%            | 58,403                 | 46.0%              |
| <b>Total</b>  | <b>166,405</b>               |                             |                  | <b>\$ 90,961,845</b>   | <b>16.0%</b>       |

(1) The current annual bill reflects the current base rates; EECR of \$0.00028, DSIM of \$0.00080, and Securitization Charge of \$0.01047.  
The proposed annual bill reflects the proposed base rates, DSIM of \$0.00080, and Securitization Charge of \$0.01047.

13  
14 **Q. Has the Company updated electric grid charges for the Community Solar Pilot**  
15 **Program (“Schedule CSPP”)?**

16 A. Yes. The electric grid charges for solar energy in Schedule CSPP have been updated to  
17 reflect the Company’s proposed class cost of service and rate design. The updated

1 electric grid charges are generally based on the methodology approved by the  
2 Commission in Case No. ET-2020-0259.<sup>15</sup> The updated electric grid charges are  
3 presented in **Direct Schedule TSL-5**.

4 **Q. Has the Company updated the tariffs related to electrification pilot programs?**

5 A. Yes. The Company has updated tariffs for Residential Smart Charge Pilot Program  
6 (“Schedule RG-SCPP”), Ready Charge Pilot Program (“Schedule RCPP”),  
7 Commercial Electrification Pilot Program (“Schedule CEPP”), and Electric School Bus  
8 Pilot Program (“Schedule ESBPP”). These tariff schedules are updated to reflect the  
9 Company’s proposed class cost of service and rate design. The charges are updated  
10 consistent with the methodology approved by the Commission in Case No. ET-2020-  
11 0390.<sup>16</sup> The updated charges are presented in **Direct Schedule TSL-5**.

12 **VII. COMMITMENTS FROM OTHER CASES**

13 **Q. Will the Company provide billing determinants consistent with the Stipulation in**  
14 **Case No. EE-2024-0232?**<sup>17</sup>

15 A. Yes. The Company will provide in its update filing billing determinants consistent  
16 with the Stipulation in Case No. EE-2024-0232.

17 **Q. Has the Company identified customer-specific transmission and distribution**  
18 **investments that are recovered through the Excess Facilities Rider (“Schedule**  
19 **XC”) and ‘Transformer Ownership’ charges, consistent with Item 21.c in the**  
20 **Stipulation in Case No. ER-2021-0312?**

---

<sup>15</sup> File No. ET-2020-0259, Order Approving Stipulation and Agreement (May 13, 2023).

<sup>16</sup> File No. ET-2020-0390, Order Approving Stipulation and Agreement (January 29, 2022).

<sup>17</sup> “In its next general rate case, Liberty will provide each tariffed rate class billing determinants (customer usage, number of bill and number of customers) by month, cycle with cycle dates that were utilized for billing purposes, and season to Staff in the following format: raw billing determinants, any and all adjustments separately (for proration, season, or any other reason) that were made to raw billing determinants, and the ending billing determinants. The ending monthly billing determinants should be the billing determinants Liberty utilizes to conduct its revenue requirement analysis in its general rate case.”

1 A. Yes. The Company identified and directly assigned to the respective FERC Accounts  
2 and rate classes in the COSS customer-specific transmission and distribution  
3 investments recovered through Schedule XC and Transformer Ownership charges.

4 **Q. Has the Company developed time-variant demand charges consistent with Item**  
5 **21.a in the Stipulation in Case No. ER-2021-0312?**

6 A. Yes. The Company developed time-variant demand charges with supporting billing  
7 determinants for classes with demand charges, as shown in **Direct Schedule TSL-5**.

8 **VIII. CASH WORKING CAPITAL REQUIREMENT**

9 **Q. Please define the term “Cash Working Capital.”**

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

16 **Q. Please describe the Company’s lead-lag study.**

17 A. The Company’s lead-lag study consists of two components: a revenue lag and expense  
18 leads. The revenue lag represents the number of days from the time customers receive  
19 service to the time customers pay for their service, *i.e.*, when the funds are available to  
20 the Company. The longer the revenue lag, the more cash the Company needs to finance  
21 its day-to-day operations.

22 The expense lead represents the number of days from the time the Company  
23 receives goods and services used to provide service to the time payments are made for  
24 those goods and services, *i.e.*, when the funds are no longer available to the Company.

1 The longer the expense lead, the less cash the Company needs to fund its day-to-day  
2 operations. Together, the revenue lag and expense leads are used to measure the lead-  
3 lag days.

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

7 **Q. What lead-lag study did the Company rely upon for its calculation of the CWC**  
8 **requirement?**

9 A. The Company relied in large part on its lead-lag study approved by the Commission in  
10 its most recent, fully litigated rate proceeding in Case No. ER-2019-0374. Specifically,  
11 the Company utilized the expense lead days that were approved by the Commission in  
12 that proceeding.

13 The Company utilized the revenue lag days that were calculated in its most  
14 recent rate case filing in Case No. ER-2021-0312 to reflect more recent collections  
15 experience.

16 **Q. What is the Company's proposed CWC requirement?**

17 A. The Company proposes a CWC requirement of (negative) \$9.6 million, as shown in  
18 the revenue requirements workpaper RB ADJ 5.

19 **IX. CONCLUSION**

20 **Q. Please briefly summarize your direct testimony.**

21 A. This testimony describes the approach used to design the proposed electric rates for the  
22 Missouri jurisdiction of the Company. The proposed base rates reflect three important  
23 utility rate design principles: (a) rates should recover the overall cost of providing

1 service; (b) rates should be fair, minimizing inter- and intra-class inequities to the  
2 extent possible; and (c) rate changes should be tempered by rate continuity concerns.

3 The Company's proposed rate design is based on the results of the Company's  
4 COSS, which shows that the current rate design produces a disparity in class rates of  
5 return. The results of the COSS support a movement toward a more equitable rate  
6 structure where class RORs move closer to the system ROR.

7 The Company prepared a bill impact analysis to evaluate the impact of the  
8 proposed base rate changes. Overall, the proposed base rates will increase a monthly  
9 bill for a Residential General customer using 1,000 kWh per month by \$30.84 per  
10 month, or 19.15 percent.<sup>18</sup>

11 **Q. Does this conclude your direct testimony at this time?**

12 **A.** Yes, it does.

---

<sup>18</sup> Based on a monthly bill for a Residential General customer using 1,000 kWh per month, including current EECR of \$0.00028 per kWh, DSIM charge of \$0.00080 per kWh, FAC charge of \$0.00811 per kWh and SUTC charge of \$0.01047.

**VERIFICATION**

I, Timothy S. Lyons, under penalty of perjury, on this 6th day of November, 2024,  
declare that the foregoing is true and correct to the best of my knowledge and belief.

/s/ Timothy S. Lyons