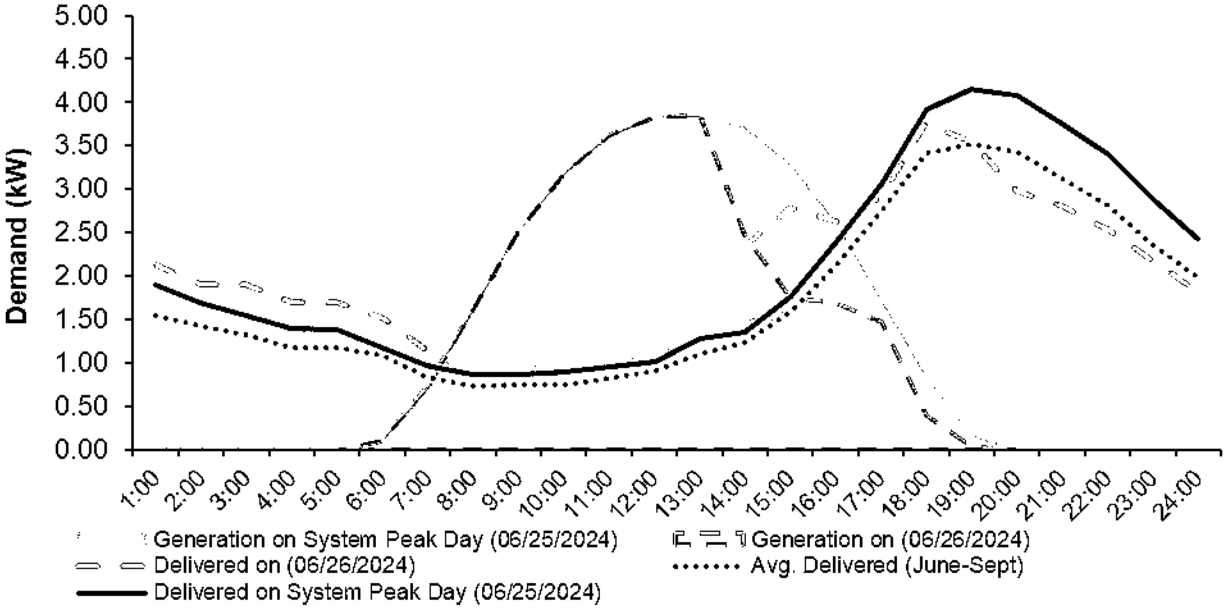
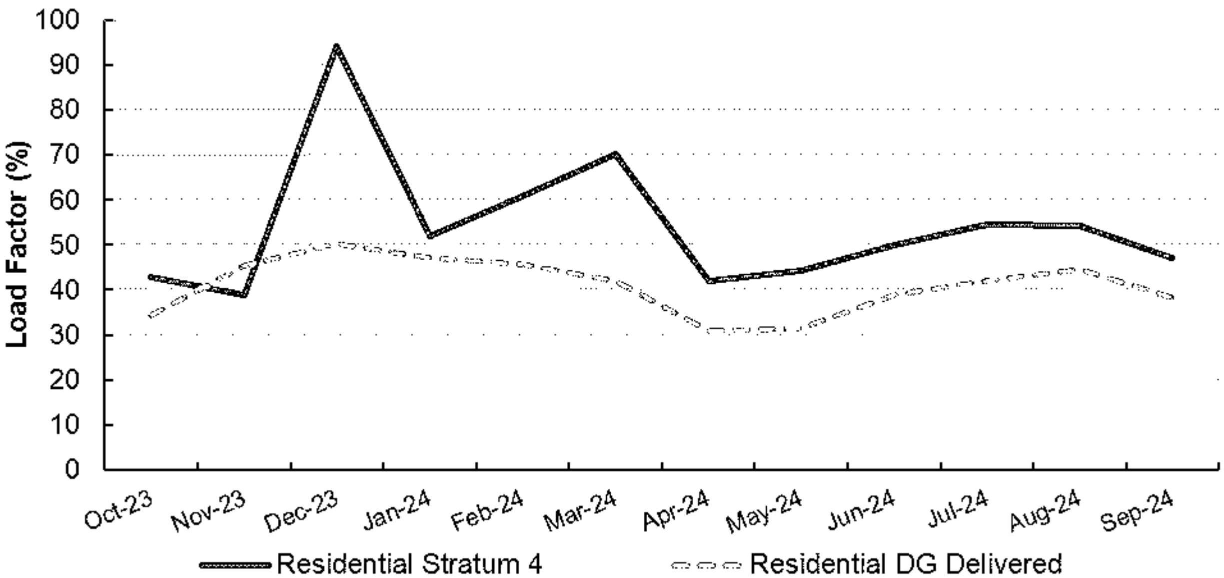
Figure 13. Delivered Demand and Generation for Residential DG Customers (June - Sept 2024)




- Although the daily consumption patterns of residential DG customers are consistently lower during the day compared to non-DG residential customers their energy consumption ramps up in the late afternoon to early evening hours.
- The lower residential DG customers' delivered load profile is highlighted by their monthly load factors shown in Figure 14. Residential DG customers have an annual average load factor of 40.90% compared to a load factor of 54.25% for residential stratum 4 customers. Low load factors occur when energy consumption is low compared to the maximum demand. As is the case with Residential DG customers, their maximum demand remains high though their energy consumption is lower due to the on-site.

Figure 14. Comparison of Load Factors for Residential DG Customers and Residential Non-DG Customers.




- On average, residential DG customers decrease their energy usage, however, they still have high maximum demand values due to unfavorable weather affecting DG production or increased demand as DG production decreases. This relationship is summarized in Table 1, below.
- Table 1 shows that during 2024, the average residential DG customer was delivered 4% less energy than the average residential non-DG customer with a maximum demand that is 24% higher resulting in a much lower load factor.

Table 1. Average Load Characteristics of Residential Non-DG and Residential DG Delivered

| | Units | December | June | Monthly Avg. |
|---|---|---|---|---|
| **Energy** | | | | |
| Residential Non-DG | kWh | 524 | 1,205 | 741 |
| Residential DG Delivered | kWh | 621 | 1,121 | 710 |
| % Difference | % | 19% | -7% | -4% |
| | | | | |
| **Demand** | | | | |
| Residential Non-DG | kW | 1.17 | 3.24 | 1.95 |
| Residential DG Delivered | kW | 1.66 | 3.58 | 2.42 |
| % Difference | % | 42% | 11% | 24% |
| | | | | |
| **Load Factor** | | | | |
| Residential Non-DG | % | 60 | 52 | 54 |
| Residential DG Delivered | % | 50 | 42 | 41 |
| % Difference | % | -17% | -19% | -24% |

- Table 2 shows that during 2024 the average residential DG customer, on a net energy basis, was billed for 62% less energy than the average residential non-DG customer but had a maximum demand that is 24% higher. This results in a much lower load factor than the delivered data shown in Table 1.
- Lower load factor customers are costlier to serve because they have a higher demand relative to their energy.

Table 2. Average Load Characteristics of Residential Non-DG and Residential DG Net

| | Units | December | June | Monthly Avg. |
|---|---|---|---|---|
| **Energy** | | | | |
| Residential Non-DG | kWh | 524 | 1,205 | 741 |
| Residential DG Net | kWh | 339 | 749 | 281 |
| % Difference | % | -35% | -38% | -62% |
| | | | | |
| **Demand** | | | | |
| Residential Non-DG | kW | 1.17 | 3.24 | 1.95 |
| Residential DG Net | kW | 1.66 | 3.58 | 2.42 |
| % Difference | % | 42% | 10% | 24% |
| | | | | |
| **Load Factor** | | | | |
| Residential Non-DG | % | 60 | 52 | 54 |
| Residential DG Net | % | 27 | 28 | 11 |
| % Difference | % | -54% | -46% | -79% |

**Exhibit ES-3 - Effect of Using Net Energy for DG Customers on Allocation Factors**



**Difference in Per Book Jurisdictional Allocators**
**Prior to the Adjustment for Dedicated Generation Resources (in Percentage Points)**

| | E1ENERGY | D1PROD 4CP-A&E | D2TRAN 4CP | D1PROD 12CP-A&E | D2TRAN 12CP |
|---|---|---|---|---|---|
| Texas | 0.1283% | -0.0068% | 0.0000% | -0.0548% | 0.0000% |
| New Mexico | -0.1444% | 0.0073% | 0.0000% | 0.0583% | 0.0000% |
| FERC | 0.0161% | -0.0005% | 0.0000% | -0.0034% | 0.0000% |

**Difference in Per Book Jurisdictional Allocators**
**After the Adjustment for Dedicated Generation Resources (in Percentage Points)**

| | E1ENERGY | D2PROD 4CP-A&E | D2PROD 4CP | D2PROD 12CP-A&E | D2PROD 12CP |
|---|---|---|---|---|---|
| Texas | 0.1380% | -0.0097% | 0.0000% | -0.0586% | 0.0000% |
| New Mexico | -0.1578% | 0.0105% | 0.0000% | 0.0624% | 0.0000% |
| FERC | 0.0198% | -0.0008% | 0.0000% | -0.0038% | 0.0000% |

Exhibit ES-3
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**Exhibit ES-3 - Effect of Using Net Energy for DG Customers on Allocation Factors**

**Difference in Adjusted Jurisdictional Allocators**
**Prior to the Adjustment for Dedicated Generation Resources (in Percentage Points)**

| | E1ENERGY | D1PROD 4CP-A&E | D2TRAN 4CP | D1PROD 12CP-A&E | D2TRAN 12CP |
|---|---|---|---|---|---|
| Texas | 0.1366% | 0.0051% | 0.0110% | -0.0423% | 0.0080% |
| New Mexico | -0.1544% | -0.0058% | -0.0121% | 0.0445% | -0.0091% |
| FERC | 0.0178% | 0.0007% | 0.0011% | -0.0021% | 0.0011% |

**Difference in Adjusted Jurisdictional Allocators**
**After the Adjustment for Dedicated Generation Resources (in Percentage Points)**

| | E1ENERGY | D2PROD 4CP-A&E | D2PROD 4CP | D2PROD 12CP-A&E | D2PROD 12CP |
|---|---|---|---|---|---|
| Texas | 0.1411% | 0.0013% | 0.0118% | -0.0506% | 0.0083% |
| New Mexico | -0.1639% | -0.0019% | -0.0132% | 0.0527% | -0.0096% |
| FERC | 0.0228% | 0.0007% | 0.0013% | -0.0022% | 0.0013% |

Exhibit ES-3
Page 2 of 4

**Exhibit ES-3 - Effect of Using Net Energy for DG Customers on Allocation Factors**



**Difference in Per Book Class Allocators (in Percentage Points)**

| Rate | E1ENERGY | E1FUEL | D1PROD 4CP-A&E | D2TRAN 4CP | D1PROD 12CP-A&E | D2TRAN 12CP | D3DIST | D4DIST | D5DIST | D6DIST | D7DIST | D8DIST | D9DIST | D10DIST |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| T-01 | -0.9154% | -0.9036% | 0.0510% | 0.0000% | 0.4123% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% |
| T-02 | 0.0896% | 0.0818% | -0.0059% | 0.0000% | -0.0753% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% |
| T-07 | 0.0014% | 0.0013% | -0.0001% | 0.0000% | -0.0027% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% |
| T-08 | 0.0089% | 0.0082% | -0.0004% | 0.0000% | -0.0004% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% |
| T-09 | 0.0006% | 0.0006% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% |
| T-11 | 0.0425% | 0.0391% | -0.0020% | 0.0000% | -0.0020% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% |
| T-15 | 0.0101% | 0.0165% | -0.0005% | 0.0000% | -0.0069% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% |
| T-WH | 0.0009% | 0.0008% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% |
| T-22 | 0.0012% | 0.0011% | -0.0001% | 0.0000% | -0.0003% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% |
| T-24 | 0.3659% | 0.3355% | -0.0209% | 0.0000% | -0.1749% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% |
| T-25 | 0.1608% | 0.1642% | -0.0084% | 0.0000% | -0.0510% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% |
| T-26 | 0.0999% | 0.0917% | -0.0048% | 0.0000% | -0.0112% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% |
| T-28 | 0.0050% | 0.0046% | -0.0002% | 0.0000% | -0.0002% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% |
| T-30 | 0.0048% | 0.0378% | -0.0003% | 0.0000% | -0.0076% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% |
| T-31 | 0.0653% | 0.0669% | -0.0036% | 0.0000% | -0.0370% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% |
| T-34 | 0.0003% | 0.0003% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% |
| T-41 | 0.0578% | 0.0530% | -0.0037% | 0.0000% | -0.0424% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% |
| T-EV | 0.0004% | 0.0004% | 0.0000% | 0.0000% | -0.0002% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% |
| Total | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% |

Exhibit ES-3
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**Exhibit ES-3 - Effect of Using Net Energy for DG Customers on Allocation Factors**



**Difference in Adjusted Class Allocators (in Percentage Points)**

| Rate | E1ENERGY | E1FUEL | D1PROD 4CP-A&E | D2TRAN 4CP | D1PROD 12CP-A&E | D2TRAN 12CP | D3DIST | D4DIST | D5DIST | D6DIST | D7DIST | D8DIST | D9DIST | D10DIST |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| T-01 | -0.9887% | -0.9750% | -0.0234% | -0.0602% | 0.3160% | -0.0720% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% |
| T-02 | 0.0962% | 0.0876% | 0.0033% | 0.0087% | -0.0622% | 0.0086% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% |
| T-07 | 0.0015% | 0.0014% | 0.0000% | 0.0000% | -0.0025% | 0.0002% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% |
| T-08 | 0.0099% | 0.0090% | 0.0002% | 0.0000% | 0.0002% | 0.0005% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% |
| T-09 | 0.0006% | 0.0005% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% |
| T-11 | 0.0475% | 0.0435% | 0.0008% | 0.0016% | 0.0008% | 0.0026% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% |
| T-15 | 0.0111% | 0.0181% | 0.0002% | 0.0006% | -0.0058% | 0.0009% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% |
| T-WH | 0.0010% | 0.0009% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% |
| T-22 | 0.0007% | 0.0007% | 0.0000% | 0.0001% | -0.0002% | 0.0001% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% |
| T-24 | 0.3898% | 0.3565% | 0.0096% | 0.0255% | -0.1336% | 0.0289% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% |
| T-25 | 0.1766% | 0.1799% | 0.0037% | 0.0094% | -0.0371% | 0.0119% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% |
| T-26 | 0.1101% | 0.1009% | 0.0019% | 0.0045% | -0.0042% | 0.0065% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% |
| T-28 | 0.0055% | 0.0050% | 0.0001% | 0.0000% | 0.0001% | 0.0003% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% |
| T-30 | 0.0053% | 0.0415% | 0.0001% | 0.0004% | -0.0067% | 0.0006% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% |
| T-31 | 0.0714% | 0.0730% | 0.0016% | 0.0044% | -0.0309% | 0.0056% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% |
| T-34 | 0.0003% | 0.0003% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% |
| T-41 | 0.0613% | 0.0562% | 0.0017% | 0.0049% | -0.0340% | 0.0052% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% |
| T-EV | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% |
| Total | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0.0000% |

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# EL PASO ELECTRIC COMPANY

**2021 Analysis of System Losses**

**September 2022**

Prepared by:

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**MANAGEMENT APPLICATIONS CONSULTING, INC.**

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September 12, 2022

Mr. James Schichtl
Vice President – Regulatory & Government Affairs
El Paso Electric Company
P. O. Box 982
El Paso, TX 79960-0982

**RE: 2021 EL PASO LOSS ANALYSES**

Dear Mr. Schichtl:

Transmitted herewith are the results of the 2021 Analysis of System Losses for El Paso Electric Company's (EPE) power system. These results consist of an Annual analysis which develops cumulative expansion factors (loss factors) for both demand (peak hour-kW) and energy (annual average-kWh) losses by discrete voltage levels applicable to metered sales data. The loss calculations were made using a separate and expanded transmission loss model to derive the final results prescribed herein. Our analyses consider only technical losses in arriving at our final recommendations.

On behalf of MAC, we appreciate the opportunity to assist you in performing the loss analysis contained herein. The level of detail, multiple databases, and multiple power flow analyses reflect reasonable and representative power losses on the El Paso Electric Company system. Our review of these data and calculated loss results support the proposed loss factors as presented herein for your use in various cost of service, rate studies, and demand analyses.

Should you require any additional information, please let us know at your earliest convenience.

Sincerely,

Paul M. Normand
Principal

# EL PASO ELECTRIC COMPANY

# 2021 ANALYSIS OF SYSTEM LOSSES

## TABLE OF CONTENTS

## 1.0 EXECUTIVE SUMMARY

This report presents El Paso Electric Company's (EPE) 2021 Analysis of System Losses for its integrated power system as performed by Management Applications Consulting, Inc. (MAC). Our analyses considered only technical losses and did not attempt to quantify non-technical factors such as theft and metering accuracy. The study developed separate one-hour peak demand (kW) and annual energy (kWh) loss factors for each voltage level of service in the power system. The cumulative loss factor results by voltage level, as presented herein, can be used to adjust metered sales data for losses to input in performing cost of service studies, determining voltage discounts, and other analyses which may require a loss adjustment.

The procedures used in the overall loss study emphasized the use of "in house" resources where possible. To this end, extensive use was made of the Company's power flow studies (ten separate analyses) and distribution plant investments in the model. Using estimated load data provided a means of calculating reasonable estimates of losses by using a "top-down" and "bottom-up" procedure. In the "top-down" approach, losses from the high voltage system, through and including distribution substations, were calculated along with power flow data, conductor and transformer loss estimates, and metered sales.

At this point in the analysis, system loads and losses at the input into the distribution substation system are known with reasonable accuracy. However, it is the remaining loads and losses on the distribution substations, primary system, secondary circuits, and services which are generally difficult to estimate. Estimated and actual Company load data provided the starting point for performing a "bottom-up" approach for calculating the remaining distribution losses. Basically, this "bottom-up" approach develops line loadings by first determining loads and losses at each level beginning at a customer's meter service entrance and then going through secondary lines, line transformers, primary lines and finally distribution substation. These distribution system loads and associated losses are then compared to the initial calculated input into Distribution Substation loadings for reasonableness prior to finalizing the loss factors. An overview of the loss study is shown on Figure 1 on page 4.

The definition of transmission losses recognized in the industry is simply to sum all losses at transmission as an integrated system. This approach will typically increase the resulting composite transmission loss factors but better reflects the topology of the systems with dispersed supply resources and interconnections. This study performed separate loss analyses for EPE's EHV (500 kV and 345 kV) networks and its local 115 kV and 69 kV networks to recognize the differing loss behavior of the two distinct transmission networks.

The load research data provided the starting point for performing a "bottom-up" approach for estimating the remaining distribution losses. Basically, this "bottom-up" approach develops line loadings by first determining loads and losses at each level beginning at a customer's meter and service entrance and then going through secondary lines, line transformers, primary lines and finally distribution substation. These distribution system loads and associated losses are then compared to the initial calculated input into Distribution Substation loadings for reasonableness. An overview of the loss study is shown on Figure 1 on page 5.

Appendix A presents the results of the El Paso Electric Company Transmission 2021 Loss Analysis for 69 kV and 115 through 345 kV and 500 kV. These results were developed using distinct power flows at loading levels representing 8,760 hours of the calendar year. The analyses were developed on a seasonal basis to reflect the varying load levels and loss characteristics for the EHV (500 kV and 345 kV) and the local transmission (115 kV and 69 kV) networks separately.

Appendix B of this report incorporates Appendix A's transmission loss results and presents the integrated total El Paso power system losses and resulting loss factors by delivery voltage. Table 1, below, provides the final results from Appendices A and B for the calendar year. The detailed distribution system losses are developed in Appendix B for all voltage levels. These loss expansion factors are applicable only to metered sales at the point of receipt for adjustment to the power system's input level.

**TABLE 1**
**Loss Factors at Sales (Metered) Level**

| Voltage Level of Service | w/ GSU* (a) | w/o GSU* (b) | Delivery (c) |
|---|---|---|---|
| Demand (kW) | | | |
| Transmission[1] | 1.02941 | 1.02752 | 1.00000 |
| Primary Substation | 1.03298 | N/A | 1.00374 |
| Primary | 1.06117 | N/A | 1.03471 |
| Secondary | 1.08208 | N/A | 1.05510 |
| Energy (kWh) | | | |
| Transmission[1] | 1.02850 | 1.02619 | 1.00000 |
| Primary Substation | 1.03349 | N/A | 1.00278 |
| Primary | 1.04670 | N/A | 1.02052 |
| Secondary | 1.07403 | N/A | 1.04717 |
| Losses – Net System Input[2] | | 6.14% MWh | |
| | | 7.04% MW | |
| Losses – Net System Output[3] | | 6.54% MWh | |
| | | 7.58% MW | |

**Generation Step Up Transformers*

[1] Reflects results from Appendix A for 500 kV, 345 kV, 115 kV and 69 kV.

[2] Net system input equals firm sales plus losses, Company use less non-requirement sales and related losses. See Appendix B, Exhibit 1, for their calculations.

[3] Net system output uses losses divided by output or sales data as a reference.

Table 1, above, presents three loss factor columns as follows:

Column (a) These loss factors are calculated with the transmission component which includes GSU losses as calculated and presented in Appendix A, Schedules 1 and 2 (Section I).

Column (b) These loss factors are similar to Column (a) except that transmission losses do not include any GSU losses as presented in Appendix A, Schedule 1 (Section II).

Column (c) These are Delivery Only loss factors that exclude all transmission losses.

The delivery voltages considered in Table 1 are defined in Appendix B, Exhibit 1, and include 1 kV through 34 kV for primary and voltages less than 1 kV for secondary.

The loss factors presented in the Delivery Only column (c) of Table 1 are the Total El Paso Electric Company loss factors divided by the transmission loss factor in order to remove the transmission losses from each service level loss factor. For example, the secondary distribution demand loss factor of 1.05510 includes the recovery of all non-transmission losses from distribution substation, primary lines, line transformers, secondary conductors and services.

The net system input shown in Table 1 represents the MWh losses of 6.14% for the total El Paso Electric Company load using calculated losses divided by the associated input energy to the system. The 7.04% represents the MW losses also using system input as a reference. The net system output reference shown in Table 1 represents MWh losses of 6.54% and MW losses of 7.58%. These results use the appropriate total losses for each but are divided by system output or sales. These calculations are all based on the results from Exhibits 1, 7 and 9 of Appendix B.

The loss factor derivations for any voltage level must consider both the load at that level plus the loads from lower voltages and their associated losses. As a result, cumulative losses on losses equates to additional load at higher levels along with future changes (+ or –) in loads throughout the power system. It is therefore important to recognize that losses are multiplicative in nature (future) and not additive (test year only) for all future years to ensure total recovery based on prospective fixed loss factors for each service voltage.

The derivation of the cumulative loss factors shown in Table 1 have been detailed for all electrical facilities in Exhibit 9, page 1 for demand and page 2 for energy. Beginning on line 1 of page 1 (demand) under the secondary column, metered sales are adjusted for service losses on lines 3 and 4. This new total load (with losses) becomes the load amount for the next higher facilities of secondary conductors and their loss calculations. This process is repeated for all the installed facilities until the secondary sales are at the input level (line 45). The final loss factor for all delivery voltages using this same process is shown on line 46 and Table 1 for demand. This procedure is repeated in Exhibit 9, page 2, for the energy loss factors.

The loss factor calculation is simply the input required (line 45) divided by the metered sales (line 2).

Table 2 below expands the Table 1 to include a separation of the transmission voltage range to identify a range of 115 kV to 500 kV and a separate 69 kV level for possible use in the Company's studies.

**TABLE 2**
**Loss Factors at Sales (Metered) Level**

| Voltage Level of Service | w/ GSU* (a) | w/o GSU* (b) | Delivery (c) |
|---|---|---|---|
| Demand (kW) | | | |
| Transmission[4] (115 kV) | 1.02557 | 1.02377 | N/A |
| Primary Substation (115 kV)** | 1.03147 | 1.02966 | 1.00575 |
| Transmission (69 kV) | 1.02941 | 1.02752 | N/A |
| Primary Substation (69 kV)** | 1.03533 | 1.03343 | 1.00575 |
| Primary | 1.06117 | 1.05931 | 1.02496 |
| Secondary | 1.08208 | 1.08018 | 1.01971 |
| Energy (kWh) | | | |
| Transmission[4] (115 kV) | 1.02565 | 1.02344 | N/A |
| Primary Substation (115 kV) | 1.03248 | 1.03047 | 1.00666 |
| Transmission (69 kV) | 1.02850 | 1.02619 | N/A |
| Primary Substation (69 kV) | 1.03535 | 1.03302 | 1.00666 |
| Primary | 1.04670 | 1.04444 | 1.01096 |
| Secondary | 1.07403 | 1.07172 | 1.02611 |
| Losses – Net System Input[5] | | 6.14% MWh | |
| | | 7.04% MW | |
| Losses – Net System Output[6] | | 6.54% MWh | |
| | | 7.58% MW | |

**Generation Step Up Transformers*
***Primary Substation Multiplier from Exhibit 8*
*MW 1.00575 MWH 1.00666*

An overview of the loss study is shown on Figure 1 on the next page. Figure 2 simply illustrates the major components that must be considered in a loss analysis.

[4] Reflects results from Appendix A for 500 kV, 345 kV, and 115 kV.
[5] Net system input equals firm sales plus losses, Company use less non-requirement sales and related losses. See Appendix B, Exhibit 1, for their calculations.
[6] Net system output uses losses divided by output or sales data as a reference.

Figure 1
MANAGEMENT APPLICATIONS CONSULTING, INC.
ELECTRIC LOSS MODEL OVERVIEW

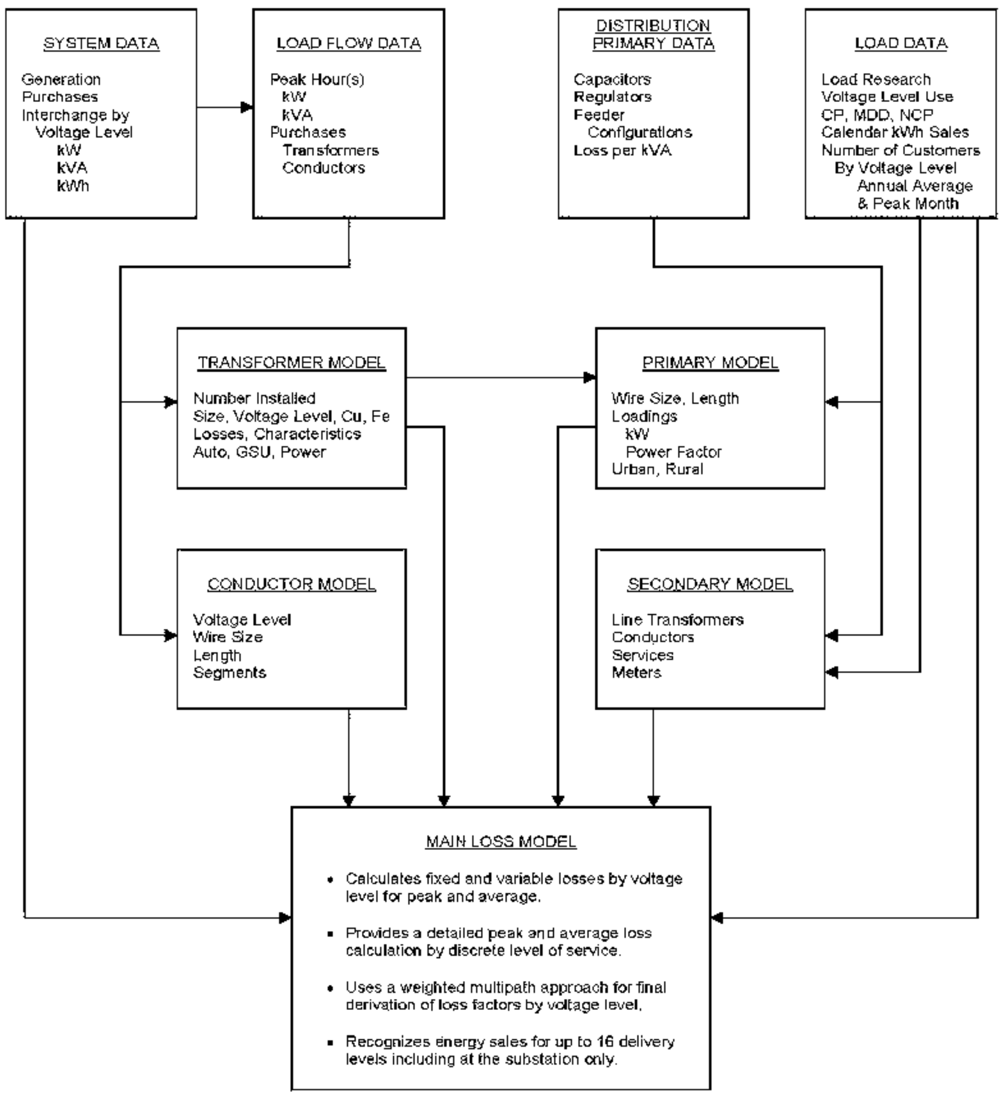
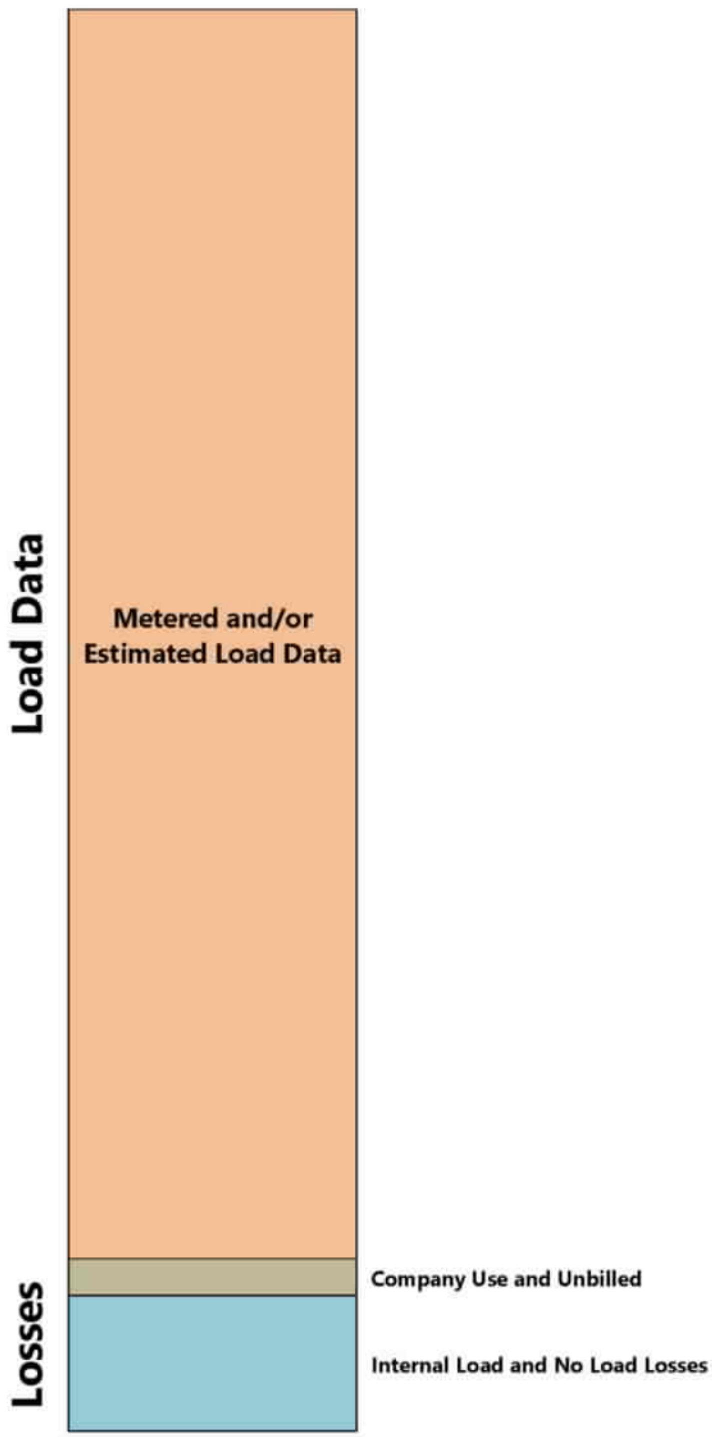


Figure 2
INTERNAL ENERGY ELEMENTS



## 2.0 INTRODUCTION

This report of the 2021 Analysis of System Losses provides a summary of results, conceptual background or methodology, description of the analyses, and input information related to the study.

### 2.1 Conduct of Study

Typically, between five to ten percent of the total peak hour MW and annual MWH requirements of an electric utility is lost or unaccounted for in the delivery of power to customers. These losses occur as a result of heating or magnetizing various electrical components of a power system. Investments must be made in facilities which support the total load which includes losses or unaccounted for load. While losses are a small portion of total delivered energy, they cannot be eliminated. Revenue requirements associated with load losses are an important concern to utilities and regulators in that customers must equitably share in all of these cost responsibilities. Loss expansion factors by voltage are the mechanism by which customers' metered demand and energy data are mathematically adjusted to the generation or input level (point of reference) when performing cost and revenue calculations.

An acceptable accounting of losses can be determined for any given time period using available engineering, system, and customer data along with empirical relationships. This loss analysis for the delivery of demand and energy utilizes such an approach. A microcomputer loss model[7] is utilized as the vehicle to organize the available data, develop the relationships, calculate the losses, and provide an efficient and timely avenue for future updates and sensitivity analyses. Our procedures and calculations are similar with prior loss studies, and they rely on numerous databases that include customer statistics and power system investments at various voltage levels of service.

Company personnel performed most of the data gathering and data processing efforts. MAC analyzed the Company's various databases and performed calculations to check the reasonableness of results. Efforts in determining the data required to perform the loss analysis centered on information which was available from existing studies or reports within the Company. From an overall perspective, our efforts concentrated on five major areas:

1. System information relating to multiple peak demands by season and metered annual sales data by voltage level,
2. High voltage power system power flow analyses and associated loss calculations,
3. Distribution system primary and secondary loss calculations,
4. Derivation of fixed and variable losses by voltage level, and
5. Development of final cumulative expansion factors at each voltage level for peak demand (kW) and annual energy (kWh) requirements reconciled to system input.

[7]Copyright by Management Applications Consulting, Inc.

## 2.2 Electric Power Losses

Losses in power systems consist of primarily technical losses with a much smaller level of non-technical losses.

Technical Losses

Electrical losses result from the transmission of energy over various electrical equipment. The largest component of total losses during peaking conditions is power dissipation as a result of varying loading conditions and are oftentimes called load losses which are mostly related to the square of the current ($I^2R$). These peak hour losses can be as high as 65% to 80% of all technical losses during peak loading conditions. The remaining losses are called no-load and represent essentially fixed (constant) energy losses throughout the year. These no-load losses represent energy required to energize various electrical equipment regardless of their loading levels over the entire year. The major portion of these no-load losses consist of core or magnetizing energy related to installed transformers throughout the power system and generates the major component of annual losses on any distribution system.

The following Table 3 summarizes the unadjusted fixed and variable losses by major functional categories from Exhibit 5 of Appendix A:

**TABLE 3**

| | DEMAND (PEAK HOUR) | | | ENERGY (ANNUAL AVERAGE) | | |
|---|---|---|---|---|---|---|
| | FIXED | VARIABLE | TOTAL | FIXED | VARIABLE | TOTAL |
| TRANS | 7.67 | 43.47 | 51.14 | 67,193 | 153,668 | 220,862 |
| (%) | 15.00% | 85.00% | 100.00% | 30.42% | 69.58% | 100.00% |
| SUBTRANS | 1.12 | 6.32 | 7.44 | 9,773 | 13,540 | 23,314 |
| (%) | 15.00% | 85.00% | 100.00% | 41.92% | 58.08% | 100.00% |
| DIST SUBS | 3.96 | 6.50 | 10.46 | 34,666 | 17,385 | 52,051 |
| (%) | 37.83% | 62.17% | 100.00% | 66.60% | 33.40% | 100.00% |
| PRIMARY | 4.24 | 51.47 | 55.71 | 37,159 | 106,893 | 144,052 |
| (%) | 7.61% | 92.39% | 100.00% | 25.80% | 74.20% | 100.00% |
| SECONDARY | 16.65 | 14.26 | 30.90 | 145,820 | 25,715 | 171,535 |
| (%) | 53.86% | 46.14% | 100.00% | 85.01% | 14.99% | 100.00% |
| TOTAL SYS | 29.67 | 115.51 | 145.19 | 259,945 | 299,817 | 559,763 |
| (%) | 20.44% | 79.56% | 100.00% | 46.44% | 53.56% | 100.00% |
| TOTAL DIST | 20.89 | 65.73 | 86.61 | 182,979 | 132,608 | 315,587 |
| (%) | 24.12% | 75.88% | 100.00% | 57.98% | 42.02% | 100.00% |

Non-Technical Losses

These are unaccounted for energy losses that are related to energy theft, metering, non-payment by customers, and accounting errors. Losses related to these areas are generally very small and can be extremely difficult and subjective to quantify. Our efforts generally do not develop any meaningful level because we assume that improving technology and utility practices have minimized these amounts.

## 2.3 Loss Impacts from Distributed Generation (DG)

The impacts of losses on a power system from the installation of various DG facilities will depend somewhat on the penetration level, type of installations and location on a circuit. Based on the results presented in Table 2 of this loss study, the impacts are significantly different from looking at any single peak load hour versus the potential impacts over all hours of an entire year. Use of a typical uniform loss factor(s) for each voltage level may require additional consideration to recognize that a reduced consumption level could have little or no impact due to the recovery requirements for the high level of fixed losses over the entire hourly electric grid condition for any DG location.

## 2.4 Description of Model

The Loss Model is a customized applications model, constructed using the Excel software program. Documentation consists primarily of the model equations at each cell location. A significant advantage of such a model is that the actual formulas and their corresponding computed values at each cell of the model are immediately available to the analyst.

A brief description of the major categories of effort for the preparation of each loss model is as follows:

- Main sheet which contains calculations for all primary and secondary losses, summaries of all conductor and transformer calculations from other sheets discussed below, output reports and supporting results.
- Transformer sheet which contains data input and loss calculations for each high voltage transformer and distribution substation. Separate iron and winding losses are calculated for each transformer by identified type.
- Conductor sheet containing summary data by major voltage level as to circuit miles, loading assumptions, and kW and kWh loss calculations. Separate loss calculations for each recognized line segment were made using the Company's power flow data and summarized by voltage level in this model.

# 3.0 METHODOLOGY

## 3.1 Background

The objective of a Loss Study is to provide a reasonable set of energy (average) and demand (peak) loss expansion factors which account for system losses associated with the transmission and delivery of power to each voltage level over a designated period of time. The focus of this study is to identify the difference between total energy inputs and the associated sales with the difference being equitably allocated to all delivery levels. Several key elements are important in establishing the methodology for calculating and reporting the Company's losses. These elements are:

- Selection of voltage level of services,
- Recognition of losses associated with conductors, transformations, and other electrical equipment/components within voltage levels,
- Identification of customers and loads at various voltage levels of service,
- Review of generation or net power supply input at each level for the test period studied, and
- Analysis of kW and kWh sales by voltage levels within the test period.

The three major areas of data gathering and calculations in the loss analysis were as follows:

1. System Information (monthly and annual)
   - MWH generation and MWH sales.
   - Coincident peak estimates and net power supply input from all sources and voltage levels.
   - Customer load data estimates from available load research information, adjusted MWH sales, and number of customers in the customer groupings and voltage levels identified in the model.
   - System default values, such as power factor, loading factors, and load factors by voltage level.
2. High Voltage System (Appendix A)
   - Conductor and transformer information was summarized from a database by the Company which reflects the transmission system by voltage level. Extensive use was made of the Company's power flow capability with the

losses calculated for ten separate load levels. Loss calculations were then performed hourly based on a linear interpolation of the ten power flow analyses and incorporated into the final loss calculations.

- Transformer information was developed in a database to model a wide range of loading transformation at each voltage level. Substation power, step-up, and auto transformers were identified along with any operating data related to loads and losses.

- Power flow data of peak and several additional load conditions were the primary source of equipment loadings and derivation of load losses in the high voltage loss calculations.

3. Distribution System (Appendix B)

- Distribution Substations – data was developed for modeling each substation as to its size and loading. Loss calculations were performed from this data to determine load and no load losses separately for each transformer.

- Primary lines – Line loading and loss characteristics were reviewed from distribution feeder analyses. These loss results developed kW loss per MW of load by Primary Voltage level. The final estimated primary losses were developed iteratively after establishing all other loss characteristics.

- Line transformers – Losses in line transformers were based on each customer service group's size, as well as the number of customers per transformer. Accounting and load data provided the foundation with which to model the transformer loadings and calculate load and no load losses.

- Secondary network – Typical secondary networks were estimated for conductor sizes, lengths, loadings, and customer penetration for residential and small general service customers.

- Services – Typical services were estimated for each secondary service class of customers identified in the study with respect to type, length, and loading.

The loss analysis was thus performed by constructing the model in segments and subsequently calculating the composite until the constraints of peak demand and energy were met:

- Information as to the physical characteristics and loading of each transformer and conductor segment was modeled.

- Conductors, transformers, and distribution were grouped by voltage level, and unadjusted losses were calculated.
- The loss factors calculated at each voltage level were determined by "compounding" the per-unit losses. Equivalent sales at the supply point were obtained by dividing sales at a specific level by the compounded loss factor to determine losses by voltage level.
- The resulting demand and energy loss expansion factors were then used to adjust all sales to the generation or input level in order to estimate the difference.
- Reconciliation of kW and kWh sales by voltage level using the reported system kW and kWh was accomplished by adjusting the initial loss factor estimates until the mismatch or difference was eliminated.

## 3.2 Calculations and Analysis

This section provides a discussion of the input data, assumptions, and calculations performed in the loss analysis. Specific appendices have been included in order to provide documentation of the input data utilized in the model.

### 3.2.1 Bulk and Transmission Lines

The transmission and subtransmission (500 kV, 345 kV, 115 kV, and 69 kV) line losses were calculated based on a modeling of unique voltage levels identified by the Company's power flow data and configuration for the entire integrated El Paso Electric Power System. Specific information as to length of line, voltage level, peak load, maximum load, etc., were provided based on Company records.

Actual loadings were based on El Paso Electric's peak loading conditions. Calculations of line losses were performed by EPE by voltage levels for reporting purposes as shown in the Discussion of Results (Section 4.0) of this report. The loss calculations consisted of determining multiple line loading levels separately and evaluating the $I^2R$ results for each recognized segment which was summed by voltage levels.

After several system coincident peak hour losses were identified by season for each major transmission voltage level, a separate calculation was then made to develop annual average energy losses based on an hourly loss calculation. Using the results of EPE's ten power flows, hourly losses were derived for hours of the calendar year as detailed in Appendix A.

### 3.2.2 Transformers

The transformer loss analysis required several steps in order to properly consider the characteristics associated with various transformer types; such as, step-up, auto transformers, distribution substations, and line transformers. In addition, further efforts were required to identify both iron and winding losses within each of these transformer types in order to obtain reasonable peak (kW) and average energy (kWh) losses. While iron losses were considered essentially constant for each hour, recognition had to be made for the varying degree of winding losses due to hourly equipment loadings.

Standardized test data tables were used to represent no load information (fixed) and full load (variable) losses for different types and sizes of distribution transformers. This test data was incorporated into the loss model to develop relationships representing winding and iron or core losses for the transformer loss calculation. These results were then totaled by various groups, as identified and discussed in Section 4.0.

The remaining miscellaneous losses considered in the loss study consisted of several areas which do not lend themselves to any reasonable level of modeling for estimating their respective losses and were therefore lumped together into a single loss factor as shown in Appendix A, Workpaper 2. The typical range of values for these losses is from 0.10% to 0.25%, and we have assumed the lower value to be conservative at this time. The losses associated with this loss factor include bus bars, unmetered station use, grounding transformers, cooling fans, heating and air conditioning requirements, and other remaining station use requirements.

### 3.2.3 Distribution System

The load data at the substation and customer level, coupled with primary and secondary network information, was sufficient to model the distribution system in adequate detail to calculate losses.

<u>Primary Lines</u>

Estimates were made by the Company of primary line losses by the different levels of distribution voltage. Our final recommendations and loss levels were derived by calculating all other loss categories with the final primary loss level estimated by subtraction.

Line Transformers

Losses in line transformers were determined based on typical transformer sizes for each secondary customer service group and an estimated or calculated number of customers per transformer. Accounting records and estimates of load data provided the necessary database with which to model the loadings. These calculations also made it possible to determine separate winding and iron losses based on a table of representative losses for various transformer sizes.

Secondary Line Circuits

Calculations of secondary line circuit losses were performed for loads served through these secondary line investments. Estimates of typical conductor sizes, lengths, loadings and customer class penetrations were made to obtain total circuit miles and losses for the secondary network. Customer loads which do not have secondary line requirements were also identified so that a reasonable estimate of losses and circuit miles of the investments could be made.

Service Drops and Meters

Service drops were estimated for each secondary customer reflecting conductor size, length and loadings to obtain demand losses. A separate calculation was also performed using customer maximum demands to obtain kWh losses. Meter loss estimates were also made for each customer and incorporated into the calculations of kW and kWh losses included in the Summary Results.

## 4.0 DISCUSSION OF RESULTS

A brief description of each Schedule and calculations is provided in **Appendix A**. A brief description of each Exhibit is provided in **Appendix B** as follows:

Exhibit 1 - Summary of Company Data

This exhibit reflects system information used to determine percent losses and a detailed summary of kW and kWh losses by voltage level. The loss factors developed in Exhibit 7 are also summarized by voltage level.

Exhibit 2 - Summary of Conductor Information

A summary of MW and MWH load and no load losses for conductors by voltage levels is presented. The sum of all calculated losses by voltage level is based on input data information provided in Appendix A. Percent losses are based on equipment loadings.

Exhibit 3 - Summary of Transformer Information

This exhibit summarizes transformer losses by various types and voltage levels throughout the system. Load losses reflect the winding portion of transformer losses while iron losses reflect the no load or constant losses. MWH losses are estimated using a calculated loss factor for winding and the test year hours times no load losses.

Exhibit 4 - Summary of Losses Diagram (2 Pages)

This loss diagram represents the inputs and output of power at system peak conditions. Page 1 details information from all points of the power system and what is provided to the distribution system for primary loads. This portion of the summary can be viewed as a “top down” summary into the distributor system.

Page 2 represents a summary of the development of primary line loads and distribution substations based on a “bottom up” approach. Basically, loadings are developed from the customer meter through the Company’s physical investments based on load research and other metered information by voltage level to arrive at MW and MVA requirements during peak load conditions by voltage levels.

Exhibit 5 - Summary of Sales and Calculated Losses

Summary of Calculated Losses represents a tabular summary of MW and MWH load and no load losses by discrete areas of delivery within each voltage level. Losses have been identified and are derived based on summaries obtained from Exhibits 2 and 3 and losses associated with meters, capacitors and regulators.

Exhibit 6 - Development of Loss Factors, Unadjusted

This exhibit calculates demand and energy losses and loss factors by specific voltage levels based on sales level requirements. The actual results reflect loads by level and summary totals of losses at that level, or up to that level, based on the results as shown in Exhibit 5. Finally, the estimated values at generation are developed and compared to actual generation to obtain any difference or mismatch.

Exhibit 7 - Development of Loss Factors, Adjusted

The adjusted loss factors are the results of adjusting Exhibit 6 for any difference. All differences between estimated and actual are prorated to each level based on the ratio of each level's total load plus losses to the system total as shown on Exhibit 8. These new loss factors reflect an adjustment in losses due only to kW and kWh mismatch.

Exhibit 8 – Adjusted Losses and Loss Factors by Facility

These calculations present an expanded summary detail of Exhibit 7 for each segment of the power system with respect to the flow of power and associated losses from the receipt of energy at the meter to the generation for the Company's power system.

Exhibit 9 – Appendix B Only – Summary of Losses by Delivery Voltage

These calculations present a reformatted summary of the losses presented in Exhibits 7 and 8 by power system delivery segment as calculated by voltage level of service based on sales.

# Appendix A

# Results of El Paso Electric Company Transmission 2021 System Loss Analysis (69 kV – 500 kV) for 69 kV and 115 to 500

## APPENDIX A

## El Paso Electric Company
## 2021 Transmission Loss Analysis
## With and Without GSU's

| | |
|---|---|
| **Pages 1-2** | Index |
| **Schedule 1A, Page 3** | Presents the summary loss results of the calculated hourly losses for the Company at the annual peak hour and for the annual average losses for all hours of the year.<br><br>Calculated loss factors are applicable to the metered (output) sales level.<br>Section I shows transmission losses of greater than or equal to 115 kV including the GSU losses.<br>Section II shows the same numbers as Section 1 except that the GSU losses (A) have been removed from the losses in B and C. |
| **Schedule 1B, Page 4** | Presents the summary loss results of the calculated hourly losses for only the 69 kV at the annual peak hour and for the annual average losses for all hours of the year.<br><br>Calculated loss factors are applicable to the metered (output) sales level.<br>Section I shows transmission losses equal to 69 kV.<br>Section II shows the same numbers as Section 1 except that the GSU losses (A) have been removed from the losses in B and C. |
| **Schedule 1C, Page 5** | Presents the summary loss results of the calculated hourly losses for the Company at the annual peak hour and for the annual average losses for all hours of the year.<br>Calculated loss factors are applicable to the metered (output) sales level.<br>Section I shows transmission losses of greater than or equal to 69 kV including the GSU losses.<br>Section II shows the same numbers as Section 1 except that the GSU losses (A) have been removed from the losses in B and C. |
| **Schedule 2, Page 6** | Section I shows the summary of the summer and winter peak hour MW and annual MWH losses for the system greater than or equal to 115 kV.<br>Section II shows the summary of the summer and winter peak hour MW and annual MWH losses for the system equal to 69 kV.<br>Results are detailed by segment and season: Summer (June, July, August, and September), Winter (all months excluding Summer months).<br>Loss data is from Schedule 3. |
| **Schedule 2, Page 7** | Section III shows the summary of the summer and winter peak hour MW and annual MWH losses for the total system.<br>Results are detailed by segment and season: Summer (June, July, August, and September), Winter (all months excluding Summer months).<br>Loss data is from Schedule 3. |
| **Schedule 3, Page 8** | Summary of MW and MWH loss results by season and voltage level. |
| **Schedule 4, Page 9** | Summary of seasonal peak hour MW and average MWH loss results for El Paso Electric Company by voltage level from Appendices A (Winter-5832 hours) and B (Summer-2928 hours) hourly loss calculations. |

## APPENDIX A

### El Paso Electric Company
### 2021 Transmission Loss Analysis
### With and Without GSU's

**Appendices:**



Detailed hourly calculation of losses for each identified type, voltage level, and season are based on ten unique power flow simulations of the Company's power system based on the following:

| Summer (June, July, August, September) Percent | Load | Winter (All other months) Percent | Load |
|---|---|---|---|
| 100 | 2051.0 | 100 | 1538.3 |
| 90 | 1845.9 | 90 | 1384.4 |
| 75 | 1538.3 | 75 | 1153.7 |
| 50 | 1025.5 | 50 | 769.1 |
| 40 | 820.4 | 40 | 615.3 |

**Workpapers:**

**Page 12** Workpaper 1 presents detailed summary results of five separate power flows for two seasons for a total of ten unique simulations and loss results.

Adjustments or additions to the results are presented at the bottom of each workpaper.

**Page 13** Workpaper 2 presents summary calculations for miscellaneous losses.

**Pages 14-15** Workpaper 3 presents Corona Loss Calculations.

Page 14 presents the Corona loss estimate and calculations by voltage level for the peak in MW and the annual MWH for 2021

Page 15 presents the pole miles by voltage level.

**EL PASO ELECTRIC COMPANY 2021 TRANSMISSION LOSS ANALYSIS**
**(Includes 115 kV to 500 kV)**

| | TRANSMISSION | LOSSES | PERCENT OF TOTAL TRANSMISSION | INPUT | OUTPUT | LOSS FACTOR (Input/Output) |
|---|---|---|---|---|---|---|
| **I.** | **WITH GSU LOSSES** | | | | | |
| | **A. DEMAND** | | **Peak (MW) Summer** | | | |
| 1 | Total Demand | 50.9 | 100.0% | 2,051 | 2,000 | 1.02545 |
| 2 | Unmetered Station Use Adjustment | 0.2 | | | | |
| 3 | Total Transmission Losses | 51.1 | | 2,051 | 2,000 | 1.02557 |
| 4 | Demand Loss Factor | | | | | 1.02557 |
| | **B. ENERGY** | | **Annual MWH** | | | |
| 5 | Total Energy | 215,074 | 100.0% | 8,641,306 | 8,426,232 | 1.02552 |
| 6 | Unmetered Station Use Adjustment | 1,045 | | | | |
| 7 | Total Transmission Losses | 216,118 | | 8,641,306 | 8,425,188 | 1.02565 |
| 8 | Energy Loss Factor | | | | | 1.02565 |
| **II.** | **EXCLUDING GSU LOSSES** | | | | | |
| | **A. GSU LOSSES** | | | | | |
| 9 | Total Demand (Peak (MW) Summer) | 3.5 | 6.9% | 2,051 | 2,047 | 1.00172 |
| 10 | Total Energy (Annual MWH) | 18,178 | 8.5% | 8,641,306 | 8,623,128 | 1.00211 |
| | **B. DEMAND** | | **Peak (MW) Summer** | | | |
| 11 | Total Demand | 47.4 | 93.1% | 2,051 | 2,004 | 1.02365 |
| 12 | Unmetered Station Use Adjustment | 0.2 | | | | |
| 13 | Total Transmission Losses | 47.6 | | 2,051 | 2,003 | 1.02377 |
| 14 | Demand Loss Factor | | | | | 1.02377 |
| | **C. ENERGY** | | **Annual MWH** | | | |
| 15 | Total Energy | 196,896 | 91.5% | 8,641,306 | 8,444,410 | 1.02332 |
| 16 | Unmetered Station Use Adjustment | 1,045 | | | | |
| 17 | Total Transmission Losses | 197,941 | | 8,641,306 | 8,443,365 | 1.02344 |
| 18 | Energy Loss Factor | | | | | 1.02344 |

**EL PASO ELECTRIC COMPANY 2021 TRANSMISSION LOSS ANALYSIS**
**(Only 69 kV)**

| | TRANSMISSION | LOSSES | PERCENT OF TOTAL TRANSMISSION | INPUT | OUTPUT | LOSS FACTOR (Input/Output) |
|---|---|---|---|---|---|---|
| I. | **WITH GSU LOSSES** | | | | | |
| | **A. DEMAND** | | **Peak (MW) Summer** | | | |
| 1 | Total Demand | 7.3 | 100.0% | 355 | 348 | 1.02097 |
| 2 | Unmetered Station Use Adjustment | 0.1 | | | | |
| 3 | Total Transmission Losses | 7.4 | | 355 | 348 | 1.02140 |
| 4 | Demand Loss Factor | | | | | 1.02140 |
| | **B. ENERGY** | | **Annual MWH** | | | |
| 5 | Total Energy | 22,624 | 100.0% | 1,667,446 | 1,644,822 | 1.01375 |
| 6 | Unmetered Station Use Adjustment | 696 | | | | |
| 7 | Total Transmission Losses | 23,320 | | 1,667,446 | 1,644,126 | 1.01418 |
| 8 | Energy Loss Factor | | | | | 1.01418 |
| II. | **EXCLUDING GSU LOSSES** | | | | | |
| | **A. GSU LOSSES** | | | | | |
| 9 | Total Demand (Peak (MW) Summer) | 0.2 | 2.1% | 355 | 355 | 1.00042 |
| 10 | Total Energy (Annual MWH) | 696 | 3.1% | 1,667,446 | 1,666,750 | 1.00042 |
| | **B. DEMAND** | | **Peak (MW) Summer** | | | |
| 11 | Total Demand | 7.1 | 97.9% | 355 | 348 | 1.02053 |
| 12 | Unmetered Station Use Adjustment | 0.1 | | | | |
| 13 | Total Transmission Losses | 7.3 | | 355 | 348 | 1.02096 |
| 14 | Demand Loss Factor | | | | | 1.02096 |
| | **C. ENERGY** | | **Annual MWH** | | | |
| 15 | Total Energy | 21,928 | 96.9% | 1,667,446 | 1,645,518 | 1.01333 |
| 16 | Unmetered Station Use Adjustment | 696 | | | | |
| 17 | Total Transmission Losses | 22,625 | | 1,667,446 | 1,644,821 | 1.01376 |
| 18 | Energy Loss Factor | | | | | 1.01376 |

**EL PASO ELECTRIC COMPANY 2021 TRANSMISSION LOSS ANALYSIS**
**(Includes 69 kV to 500 kV)**

| | TRANSMISSION | LOSSES | PERCENT OF TOTAL TRANSMISSION | INPUT | OUTPUT | LOSS FACTOR (Input/Output) |
|---|---|---|---|---|---|---|
| I. | **WITH GSU LOSSES** | | | | | |
| | **A. DEMAND** | | **Peak (MW) Summer** | | | |
| 1 | Total Demand | 58.2 | 100.0% | 2,051 | 1,993 | 1.02920 |
| 2 | Unmetered Station Use Adjustment | 0.4 | | | | |
| 3 | Total Transmission Losses | 58.6 | | 2,051 | 1,992 | 1.02941 |
| 4 | Demand Loss Factor | | | | | 1.02941 |
| | **B. ENERGY** | | **Annual MWH** | | | |
| 5 | Total Energy | 237,698 | 100.0% | 8,641,306 | 8,403,608 | 1.02829 |
| 6 | Unmetered Station Use Adjustment | 1,741 | | | | |
| 7 | Total Transmission Losses | 239,439 | | 8,641,306 | 8,401,867 | 1.02850 |
| 8 | Energy Loss Factor | | | | | 1.02850 |
| II. | **EXCLUDING GSU LOSSES** | | | | | |
| | **A. GSU LOSSES** | | | | | |
| 9 | Total Demand (Peak (MW) Summer) | 3.7 | 6.3% | 2,051 | 2,047 | 1.00179 |
| 10 | Total Energy (Annual MWH) | 18,873 | 7.9% | 8,641,306 | 8,622,433 | 1.00219 |
| | **B. DEMAND** | | **Peak (MW) Summer** | | | |
| 11 | Total Demand | 54.5 | 93.7% | 2,051 | 1,996 | 1.02731 |
| 12 | Unmetered Station Use Adjustment | 0.4 | | | | |
| 13 | Total Transmission Losses | 54.9 | | 2,051 | 1,996 | 1.02752 |
| 14 | Demand Loss Factor | | | | | 1.02752 |
| | **C. ENERGY** | | **Annual MWH** | | | |
| 15 | Total Energy | 218,825 | 92.1% | 8,641,306 | 8,422,481 | 1.02598 |
| 16 | Unmetered Station Use Adjustment | 1,741 | | | | |
| 17 | Total Transmission Losses | 220,566 | | 8,641,306 | 8,420,740 | 1.02619 |
| 18 | Energy Loss Factor | | | | | 1.02619 |

**EL PASO ELECTRIC COMPANY POWER FLOW RESULTS - SUMMARY OF LOSSES**

| | PEAK (SUMMER) | | PEAK (WINTER) | | ANNUAL | |
|---|---|---|---|---|---|---|
| | Total (MW) | % of Total System | Total (MW) | % of Total System | Total Annual (MWH) | % of Total System |
| I. **115 kV to 500 kV** | | | | | | |
| 1 Load (Peak MW, Annual MWH) | 2,051 | | 1,615 | | 8,641,306 | |
| | 100.00% | | 78.74% | | | |
| Transmission Losses | | | | | | |
| 2 Transformers | 5.0 | 9.9% | 4.5 | 11.3% | 27,222 | 12.7% |
| 3 Transmission Lines | 45.9 | 90.1% | 35.5 | 88.7% | 187,851 | 87.3% |
| 4 Total Transmission Losses | 50.9 | 100.0% | 40.0 | 100.0% | 215,074 | 100.0% |
| 5 Losses % of Input (Line 4/Line 1) | 2.48% | | 2.48% | | 2.49% | |
| 6 Losses % of Output (Line 4/(Line 1/Line 4)) | 2.54% | | 2.54% | | 2.55% | |

| | SUMMER AVERAGE | | WINTER AVERAGE | | ANNUAL AVERAGE | |
|---|---|---|---|---|---|---|
| 7 Load (All data in MWH) | 3,656,293 | | 4,985,013 | | 8,641,306 | |
| | 42.31% | | 57.69% | | 100.00% | |
| Transmission Losses | | | | | | |
| 8 Transformers | 10,953 | 11.8% | 16,270 | 13.3% | 27,222 | 12.7% |
| 9 Transmission Lines | 82,122 | 88.2% | 105,729 | 86.7% | 187,851 | 87.3% |
| 10 Total Transmission Losses | 93,075 | 100.0% | 121,999 | 100.0% | 215,074 | 100.0% |
| 11 Losses % of Input (Line 10/Line 7) | 2.55% | | 2.45% | | 2.49% | |
| 12 Losses % of Output (Line 10/(Line 7/Line 10)) | 2.61% | | 2.51% | | 2.55% | |

| | PEAK (SUMMER) | | PEAK (WINTER) | | ANNUAL | |
|---|---|---|---|---|---|---|
| | Total (MW) | % of Total System | Total (MW) | % of Total System | Total Annual (MWH) | % of Total System |
| II. **69 kV** | | | | | | |
| 13 Load (Peak MW, Annual MWH) | 355 | | 280 | | 1,667,446 | |
| (Appendix B, Exhibit 5, Line 11) | | | 78.74% | | | |
| Transmission Losses | | | | | | |
| 14 Transformers | 0.8 | 11.2% | 0.7 | 14.9% | 4,884 | 21.6% |
| 15 Transmission Lines | 6.5 | 88.8% | 4.2 | 85.1% | 17,740 | 78.4% |
| 16 Total Transmission Losses | 7.3 | 100.0% | 4.9 | 100.0% | 22,624 | 100.0% |
| 17 Losses % of Input (Line 16/Line 13) | 2.05% | | 1.75% | | 1.36% | |
| 18 Losses % of Output (Line 16/(Line 13/Line 16)) | 2.10% | | 1.78% | | 1.38% | |

| | SUMMER AVERAGE | | WINTER AVERAGE | | ANNUAL AVERAGE | |
|---|---|---|---|---|---|---|
| 19 Load (All data in MWH) | 705,527 | | 961,919 | | 1,667,446 | |
| | 42.31% | | 57.69% | | 100.00% | |
| Transmission Losses | | | | | | |
| 20 Transformers | 1,919 | 18.1% | 2,965 | 24.7% | 4,884 | 21.6% |
| 21 Transmission Lines | 8,688 | 81.9% | 9,052 | 75.3% | 17,740 | 78.4% |
| 22 Total Transmission Losses | 10,607 | 100.0% | 12,017 | 100.0% | 22,624 | 100.0% |
| 23 Losses % of Input (Line 22/Line19) | 1.50% | | 1.25% | | 1.36% | |
| 24 Losses % of Output (Line 22/(Line 19/Line 22)) | 1.53% | | 1.27% | | 1.38% | |

**EL PASO ELECTRIC COMPANY POWER FLOW RESULTS - SUMMARY OF LOSSES**

| | PEAK (SUMMER) | | PEAK (WINTER) | | ANNUAL | |
|---|---|---|---|---|---|---|
| | Total (MW) | % of Total System | Total (MW) | % of Total System | Total Annual (MWH) | % of Total System |
| III. **Total (Includes 69 kV to 500 Kv)** | | | | | | |
| 25 Load (Peak MW, Annual MWH) | 2,051 | | 1,615 | | 8,641,306 | |
| Transmission Losses | | | | | | |
| 26 Transformers | 5.9 | 10.1% | 5.3 | 11.7% | 32,107 | 13.5% |
| 27 Transmission Lines | 52.3 | 89.9% | 39.6 | 88.3% | 205,591 | 86.5% |
| 28 Total Transmission Losses | 58.2 | 100.0% | 44.9 | 100.0% | 237,698 | 100.0% |
| 29 Losses % of Input (Line 28/Line 25) | 2.84% | | 2.78% | | 2.75% | |
| 30 Losses % of Output (Line 28/(Line 25/Line 28)) | 2.92% | | 2.86% | | 2.83% | |

| | SUMMER AVERAGE | | WINTER AVERAGE | | ANNUAL AVERAGE | |
|---|---|---|---|---|---|---|
| 31 Load (All data in MWH) | 3,656,293 | | 4,985,013 | | 8,641,306 | |
| Transmission Losses | | | | | | |
| 32 Transformers | 12,874 | 12.4% | 19,235 | 14.4% | 32,107 | 13.5% |
| 33 Transmission Lines | 90,810 | 87.6% | 114,781 | 85.6% | 205,591 | 86.5% |
| 34 Total Transmission Losses | 103,684 | 100.0% | 134,016 | 100.0% | 237,698 | 100.0% |
| 35 Losses % of Input (Line 34/Line 31) | 2.84% | | 2.69% | | 2.75% | |
| 26 Losses % of Output (Line 34/(Line 31/Line 34)) | 2.92% | | 2.76% | | 2.83% | |

## EL PASO ELECTRIC COMPANY POWER FLOW RESULTS - TOTAL TRANSMISSION

| | | TRANSFORMER LOSSES MW | | | | | | TRANSMISSION LINE LOSSES MW | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **TIME** | **MW INPUT** | **345 kV** | **115 kV** | **69 kV** | **GSU - 115 kV** | **GSU - 69 kV** | **Subtotal Transformers** | **500 kV** | **345 kV** | **Corona 345 kV to 138 kV** | **115 kV** | **69 kV** | **Subtotal Transm Lines** | **Total Transmission Losses** |
| **WINTER** | | | | | | | | | | | | | | |
| 1 PEAK - MW | 1,615 | 0.000 | 1.263 | 0.568 | 3.262 | 0.158 | 5.250 | 4.857 | 13.951 | 2.839 | 13.814 | 4.156 | 39.618 | 44.868 |
| 2 LOSS % TO INPUT | | 0.000% | 0.078% | 0.035% | 0.202% | 0.010% | 0.325% | 0.301% | 0.864% | 0.176% | 0.855% | 0.257% | 2.453% | |
| 3 LOSS % TO TOTAL LOSSES | | | | | | | 11.701% | | | | | | 88.299% | 100.000% |
| 4 | | | | | | | | | | | | | | |
| 5 WINTER MWH | 4,985,013 | 0 | 5,780 | 2,658 | 10,489 | 307 | 19,235 | 10,223 | 50,469 | 16,559 | 28,478 | 9,052 | 114,781 | 134,016 |
| 6 LOSS % TO INPUT | | 0.000% | 0.116% | 0.053% | 0.210% | 0.006% | 0.386% | 0.205% | 1.012% | 0.332% | 0.571% | 0.182% | 2.303% | |
| 7 LOSS % TO TOTAL LOSSES | | | | | | | 14.353% | | | | | | 85.647% | 100.000% |
| **SUMMER** | | | | | | | | | | | | | | |
| 8 PEAK - MW | 2,051 | 0.000 | 1.510 | 0.670 | 3.520 | 0.150 | 5.850 | 5.077 | 19.630 | 2.839 | 18.320 | 6.470 | 52.337 | 58.187 |
| 9 LOSS % TO INPUT | | 0.000% | 0.074% | 0.033% | 0.172% | 0.007% | 0.285% | 0.248% | 0.957% | 0.138% | 0.893% | 0.315% | 2.552% | |
| 10 LOSS % TO TOTAL LOSSES | | | | | | | 10.054% | | | | | | 89.946% | 100.000% |
| 11 | | | | | | | | | | | | | | |
| 12 SUMMER MWH | 3,656,293 | 0 | 3,265 | 1,530 | 7,688 | 389 | 12,874 | 9,996 | 34,287 | 8,314 | 29,525 | 8,688 | 90,810 | 103,684 |
| 13 LOSS % TO INPUT | | 0.000% | 0.089% | 0.042% | 0.210% | 0.011% | 0.352% | 0.273% | 0.938% | 0.227% | 0.808% | 0.238% | 2.484% | |
| 14 LOSS % TO TOTAL LOSSES | | | | | | | 12.416% | | | | | | 87.584% | 100.000% |
| **TOTAL ANNUAL** | | | | | | | | | | | | | | |
| 15 PEAK - MW | 2,051 | 0.000 | 1.510 | 0.670 | 3.520 | 0.150 | 5.850 | 5.077 | 19.630 | 2.839 | 18.320 | 6.470 | 52.337 | 58.187 |
| 16 ANNUAL MWH | 8,641,306 | 0 | 9,045 | 4,189 | 18,178 | 696 | 32,107 | 20,219 | 84,756 | 24,873 | 58,003 | 17,740 | 205,591 | 237,698 |
| 17 LOSS % TO INPUT | | 0.000% | 0.105% | 0.048% | 0.210% | 0.008% | 0.372% | 0.234% | 0.981% | 0.288% | 0.671% | 0.205% | 2.379% | |
| 18 LOSS % TO TOTAL ANNUAL INPUT | | | | | | | 13.507% | | | | | | 86.493% | 100.000% |
| 19 LOSS % TO TOTAL ANNUAL OUTPUT | | | | | | | | | | | | | | 8,403,608 |
| 20 (Input - Losses) | | | | | | | | | | | | | | 2.829% |
| **LOSS FACTORS** | | | | | | | | | | | | | | |
| 21 Demand | | | | | | | | | | | | | | 1.02920 |
| 22 Energy | | | | | | | | | | | | | | 1.02829 |

## EL PASO ELECTRIC COMPANY POWER FLOW RESULTS

| TIME | MW INPUT | TRANSFORMER LOSSES MW 345 kV | 115 kV | 69 kV | GSU - 115 kV | GSU - 69 kV | Subtotal Transformers | TRANSMISSION LINE LOSSES MW 500 kV | 345 kV | Corona 345 kV to 138 kV | 115 kV | 69 kV | Subtotal Transm Lines | Total Transmission Losses |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **WINTER** | | | | | | | | | | | | | | |
| 1 PEAK - MW | 1,615 | 0.000 | 1.263 | 0.568 | 3.262 | 0.158 | 5.250 | 4.857 | 13.951 | 2.839 | 13.814 | 4.156 | 39.618 | 44.868 |
| 2 LOSS % TO INPUT | | 0.000% | 0.078% | 0.035% | 0.202% | 0.010% | 0.325% | 0.301% | 0.864% | 0.176% | 0.855% | 0.257% | 2.453% | |
| 3 LOSS % TO TOTAL LOSSES | | | | | | | 11.701% | | | | | | 88.299% | 100.000% |
| 4 | | | | | | | | | | | | | | |
| 5 WINTER MWH | 4,985,013 | 0 | 5,780 | 2,658 | 10,489 | 307 | 19,235 | 10,223 | 50,469 | 16,559 | 28,478 | 9,052 | 114,781 | 134,016 |
| 6 LOSS % TO INPUT | | 0.000% | 0.116% | 0.053% | 0.210% | 0.006% | 0.386% | 0.205% | 1.012% | 0.332% | 0.571% | 0.182% | 2.303% | |
| 7 LOSS % TO TOTAL LOSSES | | | | | | | 14.353% | | | | | | 85.647% | 100.000% |
| **SUMMER** | | | | | | | | | | | | | | |
| 8 PEAK - MW | 2,051 | 0.000 | 1.510 | 0.670 | 3.520 | 0.150 | 5.850 | 5.077 | 19.630 | 2.839 | 18.320 | 6.470 | 52.337 | 58.187 |
| 9 LOSS % TO INPUT | | 0.000% | 0.074% | 0.033% | 0.172% | 0.007% | 0.285% | 0.248% | 0.957% | 0.138% | 0.893% | 0.315% | 2.552% | |
| 10 LOSS % TO TOTAL LOSSES | | | | | | | 10.054% | | | | | | 89.946% | 100.000% |
| 11 | | | | | | | | | | | | | | |
| 12 SUMMER MWH | 3,656,293 | 0 | 3,265 | 1,530 | 7,688 | 389 | 12,872 | 9,996 | 34,287 | 8,314 | 29,525 | 8,688 | 90,810 | 103,682 |
| 13 LOSS % TO INPUT | | 0.000% | 0.089% | 0.042% | 0.210% | 0.011% | 0.352% | 0.273% | 0.938% | 0.227% | 0.808% | 0.238% | 2.484% | |
| 14 LOSS % TO TOTAL LOSSES | | | | | | | 12.415% | | | | | | 87.585% | 100.000% |
| **TOTAL ANNUAL** | | | | | | | | | | | | | | |
| 15 PEAK - MW | 2,051 | 0.000 | 1.510 | 0.670 | 3.520 | 0.150 | 5.850 | 5.077 | 19.630 | 2.839 | 18.320 | 6.470 | 52.337 | 58.187 |
| 16 ANNUAL MWH | 8,641,306 | 0 | 9,045 | 4,189 | 18,178 | 696 | 32,107 | 20,219 | 84,756 | 24,873 | 58,003 | 17,740 | 205,591 | 237,698 |
| 17 LOSS % TO INPUT | | 0.000% | 0.105% | 0.048% | 0.210% | 0.008% | 0.372% | 0.234% | 0.981% | 0.288% | 0.671% | 0.205% | 2.379% | |
| 18 LOSS % TO TOTAL ANNUAL INPUT | | | | | | | 13.507% | | | | | | 86.493% | 100.000% |
| 19 LOSS % TO TOTAL ANNUAL OUTPUT | | | | | | | | | | | | | | 8,403,608 |
| 20 (Input - Losses) | | | | | | | | | | | | | | 2.829% |
| **LOSS FACTORS** | | | | | | | | | | | | | | |
| 21 Demand | | | | | | | | | | | | | | 1.02920 |
| 22 Energy | | | | | | | | | | | | | | 1.02829 |

| | Winter Hours | Summer Hours | Total Hours | Percent of Total Hours |
|---|---|---|---|---|
| **PERCENT RANGE** | | | | |
| 23 91-100 | 93 | 96 | 189 | 2.16% |
| 24 76-90 | 240 | 569 | 809 | 9.24% |
| 25 51-75 | 3,685 | 1,306 | 4,991 | 56.97% |
| 26 41-50 | 1,798 | 823 | 2,621 | 29.92% |
| 27 1-40 | 16 | 134 | 150 | 1.71% |
| 28 Total Hours | 5,832 | 2,928 | 8,760 | 100.00% |

**NOTES:**

(1) Summer Period includes June, July, August, and September.
(2) Winter Period includes all non Summer months.

**EL PASO ELECTRIC COMPANY POWER FLOW RESULTS - WINTER SUMMARY**

| | | TRANSFORMER LOSSES MW | | | | | | TRANSMISSION LINE LOSSES MW | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| TIME | MW | 345 kV | 115 kV | 69 kV | GSU - 115 kV | GSU - 69 kV | Subtotal Transformers | 500 kV | 345 kV | 115 kV | 69 kV | BELOW 69 kV | Subtotal Transm Lines | Total Transmission Losses |
| 1 PEAK - MW | 1,615 | 0.000 | 1.263 | 0.568 | 3.262 | 0.158 | 5.250 | 4.857 | 13.951 | 13.814 | 4.156 | 0.000 | 36.778 | 42.028 |
| 2 LOSS % TO INPUT | | 0.000% | 0.078% | 0.035% | 0.000% | 0.000% | 0.325% | 0.301% | 0.864% | 0.855% | 0.257% | 0.000% | 2.277% | |
| 3 LOSS % TO TOTAL | | | | | | | 12.492% | | | | | | 87.508% | 100.000% |
| 4 | | | | | | | | | | | | | | |
| 5 WINTER MWH | 4,985,013 | 0 | 5,780 | 2,658 | 10,489 | 307 | 19,235 | 10,223 | 50,469 | 28,478 | 9,052 | 0 | 98,221 | 117,456 |
| 6 LOSS % TO INPUT | | 0.000% | 0.116% | 0.053% | 0.210% | 0.006% | 0.386% | 0.205% | 1.012% | 0.571% | 0.182% | 0.000% | 1.970% | |
| 7 LOSS % TO TOTAL | | | | | | | 16.376% | | | | | | 83.624% | 100.000% |
| 8 | | | | | | | | | | | | | | |
| 9 | | | | | | | | | | | | | | |
| 10 | | | | | | | | | | | | | | |

## EL PASO ELECTRIC COMPANY POWER FLOW RESULTS - SUMMER SUMMARY

| TIME | MW | TRANSFORMER LOSSES MW 345 kV | 115 kV | 69 kV | GSU - 115 kV | GSU - 69 kV | Subtotal Transformers | TRANSMISSION LINE LOSSES MW 500 kV | 345 kV | 115 kV | 69 kV | BELOW 69 kV | Subtotal Transm Lines | Total Transmission Losses |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 PEAK - MW | 2,051 | 0.000 | 1.510 | 0.670 | 3.520 | 0.150 | 5.850 | 5.077 | 19.630 | 18.320 | 6.470 | 0.000 | 49.497 | 55.347 |
| 2 LOSS % TO INPUT | | 0.000% | 0.074% | 0.033% | 0.172% | 0.007% | 0.285% | 0.248% | 0.957% | 0.893% | 0.315% | 0.000% | 2.413% | |
| 3 LOSS % TO TOTAL | | | | | | | 10.570% | | | | | | 89.430% | 100.000% |
| 4 | | | | | | | | | | | | | | |
| 5 SUMMER MWH | 3,656,293 | 0 | 3,265 | 1,530 | 7,688 | 389 | 12,872 | 9,996 | 34,287 | 29,525 | 8,688 | 0 | 82,496 | 95,368 |
| 6 LOSS % TO INPUT | | 0.000% | 0.089% | 0.042% | 0.210% | 0.011% | 0.352% | 0.273% | 0.938% | 0.808% | 0.238% | 0.000% | 2.256% | |
| 7 LOSS % TO TOTAL | | | | | | | 13.497% | | | | | | 86.503% | 100.000% |
| 8 | | | | | | | | | | | | | | |
| 9 | | | | | | | | | | | | | | |
| 10 | | | | | | | | | | | | | | |

El Paso Electric Company (345 kV to 69 kV)
2021 Transmission Loss Analysis

| | 13 Summer 100% | 13 Summer 90% | 13 Summer 75% | 13 Summer 50% | 13 Summer 40% | 13 Winter 100% | 13 Winter 90% | 13 Winter 75% | 13 Winter 50% | 13 Winter 40% |
|---|---|---|---|---|---|---|---|---|---|---|
| MW | LOAD 2,051.0 | LOAD 1,845.9 | LOAD 1,538.3 | LOAD 1,025.5 | LOAD 820.4 | LOAD 1,538.3 | LOAD 1,384.4 | LOAD 1,153.7 | LOAD 769.1 | LOAD 615.3 |
| TRANSFOMER LOSSES | | | | | | | | | | |
| KV LEVEL | kW | kW | kW | kW | kW | kW | kW | kW | kW | kW |
| ALL DISTRIBUTION XFMRS* | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| BELOW 69 kV | | | | | | | | | | |
| 69 kV | 670.0 | 640.0 | 540.0 | 490.0 | 490.0 | 540.0 | 520.0 | 500.0 | 440.0 | 440.0 |
| 115 kV | 1,510.0 | 1,450.0 | 1,200.0 | 1,040.0 | 910.0 | 1,200.0 | 1,160.0 | 1,170.0 | 930.0 | 940.0 |
| 345 kV | | | | | | | | | | |
| GSU - 69 kV | 150.0 | 150.0 | 150.0 | 120.0 | 120.0 | 150.0 | 160.0 | 150.0 | 20.0 | 20.0 |
| GSU - 115 kV | 3,520.0 | 3,330.0 | 3,120.0 | 2,250.0 | 2,120.0 | 3,100.0 | 2,800.0 | 1,890.0 | 1,790.0 | 1,390.0 |
| SUBTOTAL | 5,850.0 | 5,570.0 | 5,010.0 | 3,900.0 | 3,640.0 | 4,990.0 | 4,640.0 | 3,710.0 | 3,180.0 | 2,790.0 |
| LINE LOSSES | | | | | | | | | | |
| KV LEVEL | kW | kW | kW | kW | kW | kW | kW | kW | kW | kW |
| BELOW 69 kV | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 69 kV | 6,470.0 | 5,660.0 | 3,980.0 | 2,030.0 | 1,390.0 | 3,950.0 | 3,200.0 | 2,360.0 | 1,260.0 | 1,120.0 |
| 115 kV | 18,320.0 | 16,590.0 | 13,160.0 | 7,410.0 | 6,120.0 | 13,130.0 | 11,160.0 | 8,310.0 | 3,740.0 | 2,850.0 |
| 345 kV | 19,630.0 | 18,910.0 | 13,280.0 | 9,680.0 | 8,640.0 | 13,260.0 | 11,750.0 | 13,930.0 | 7,000.0 | 6,880.0 |
| 500 kV | 5,077.5 | 3,829.5 average | 4,463.2 average | 2,779.2 average | 2,137.8 average | 1,292.0 | 1,217.7 | 2,045.3 average | 1,763.6 average | 1,382.4 average |
| SUBTOTAL | 49,497.5 | 44,989.5 | 34,883.2 | 21,899.2 | 18,287.8 | 31,632.0 | 27,327.7 | 26,645.3 | 13,763.6 | 12,232.4 |
| COMBINED LOSSES (Lines & Xfmrs) | | | | | | | | | | |
| KV LEVEL | kW | kW | kW | kW | kW | kW | kW | kW | kW | kW |
| GSU | 3,670.0 | 3,480.0 | 3,270.0 | 2,370.0 | 2,240.0 | 3,250.0 | 2,960.0 | 2,040.0 | 1,810.0 | 1,410.0 |
| 69 kV | 7,140.0 | 6,300.0 | 4,520.0 | 2,520.0 | 1,880.0 | 4,490.0 | 3,720.0 | 2,860.0 | 1,700.0 | 1,560.0 |
| 115 kV | 19,830.0 | 18,040.0 | 14,360.0 | 8,450.0 | 7,030.0 | 14,330.0 | 12,320.0 | 9,480.0 | 4,670.0 | 3,790.0 |
| 345 kV | 19,630.0 | 18,910.0 | 13,280.0 | 9,680.0 | 8,640.0 | 13,260.0 | 11,750.0 | 13,930.0 | 7,000.0 | 6,880.0 |
| 500 kV | 5,077.5 | 3,829.5 | 4,463.2 | 2,779.2 | 2,137.8 | 1,292.0 | 1,217.7 | 2,045.3 | 1,763.6 | 1,382.4 |
| TOTAL EPE Sytem Losses | 55,347.5 | 50,559.5 | 39,893.2 | 25,799.2 | 21,927.8 | 36,622.0 | 31,967.7 | 30,355.3 | 16,943.6 | 15,022.4 |
| Corona | 2,839.4 | 2,839.4 | 2,839.4 | 2,839.4 | 2,839.4 | 2,839.4 | 2,839.4 | 2,839.4 | 2,839.4 | 2,839.4 |
| Total EPE Sytem Losses with Corona | 58,186.9 | 53,398.9 | 42,732.6 | 28,638.6 | 24,767.2 | 39,461.4 | 34,807.1 | 33,194.8 | 19,783.0 | 17,861.8 |

Notes:
(1) Source file for loss data "EPE_Substation_Losses_2021_V4 MAC.xlsx"
(2) Source for summer and winter peaks is 2021/ Q4 FERC Form 1, page 400
Monthly Peak MW - Total Summer 2,051 Winter 1,615.0
(3) Source for Winter losses of 1538.3 at 100% calculated from EPE's available cases

**Workpaper 2 (Miscellaneous Losses)**

| | (Includes 115 kV to 500 kV) | (Only 69 kV) | (Includes 69 kV to 500 kV) |
|---|---|---|---|
| A. Transmission Unmetered Energy Losses | | | |
| Transmission Substations | 9 | 6 | 15 |
| Assumed Unmetered Station Use | 25 kVA | 25 kVA | 25 kVA |
| Hours | 8760 | 8760 | 8760 |
| Load Factor | 53% | 53% | 53% |
| Unmetered Use (MWH) | 1,045 | 696 | 1,741 |
| Annual Hourly Energy | 8,426,232 | 1,644,822 | 8,403,608 |
| Unmetered Losses @ | 0.01% of Transmission Load | 0.04% of Transmission Load | 0.02% of Transmission Load |
| Peak Load (Schedule 1 w/o Losses) | 2,000 MW * | 348 MW * | 1,993 MW * |
| | 0.01% = | 0.04% = | 0.02% = |
| | 0.2 MW | 0.1 MW | 0.4 MW |
| Annual (Schedule 1 w/o Losses) | 8,426,232 MWH * | 1,644,822 MWH * | 8,403,608 MWH * |
| | 0.01% = | 0.04% = | 0.02% = |
| | 1,045 MWH | 696 MWH | 1,741 MWH |
| B. Distribution Unmetered Energy Losses | | | |
| Distribution Substations | 67 | 31 | 88 |
| Estimated Large Substation Factor | 50% | 50% | 50% |
| Assumed Unmetered Station Use | 15 kVA | 15 kVA | 15 kVA |
| Hours | 8760 | 8760 | 8760 |
| Load Factor | 60% | 60% | 60% |
| Unmetered Use (MWH) | 2,641 | 1,222 | 3,469 |
| Annual Hourly Energy | 5,350,000 | 1,765,000 | 7,135,000 |
| Unmetered Losses @ | 0.05% of Distribution Load | 0.07% of Distribution Load | 0.05% of Distribution Load |
| Peak Load | 1,250 MW * | 420 MW * | 1,680 MW * |
| | 0.05% = | 0.07% = | 0.05% = |
| | 0.6 MW | 0.3 MW | 0.8 MW |
| Annual | 8,426,232 MWH * | 1,644,822 MWH * | 8,403,608 MWH * |
| | 0.05% = | 0.07% = | 0.05% = |
| | 4,160 MWH | 1,139 MWH | 4,086 MWH |

## CORONA LOSS ESTIMATE

| | | VOLTAGE (kV) | MILES | CORONA PEAK LOSS FACTOR (MW Mile) | CORONA LOSSES (MW) | CORONA WINTER HOURS & LOSSES (MWH) | CORONA SUMMER HOURS & LOSSES (MWH) | CORONA TOTAL LOSSES (MWH) |
|---|---|---|---|---|---|---|---|---|
| A. | Fair Weather Corona Losses | | | | | | | |
| 1 | Hours | | | | | 5,832 | 2,928 | |
| 2 | | 500 | 165 | 0.0000 | 0.000 | 0 | 0 | 0 |
| 3 | | 345 | 946 | 0.0030 | 2.839 | 16,559 | 8,314 | 24,873 |
| 4 | | 115 | 522 | 0.0000 | 0.000 | 0 | 0 | 0 |
| 5 | | 69 | 216 | 0.0000 | 0.000 | 0 | 0 | 0 |
| 6 | TOTAL | | 1,849 | | 2.839 | 16,559 | 8,314 | 24,873 |

NOTE:
(1) Line 6 loss results included in Schedules 3 and 4.

## Pole Miles

| | Voltage | Total |
|---|---|---|
| 1 | 500 | 165 |
| 2 | 345 | 946 |
| 3 | 115 | 522 |
| 4 | 69 | 216 |
| 5 | **Total Pole Miles** | 1,849 |

NOTE:
(1) Source 2021 FERC Form 1 El Paso Electric Company,

# Appendix B

# Results of El Paso Electric Company 2021 Loss Analysis – Transmission and Distribution

## (with Generation Step Up (GSU) Losses)

EL PASO ELECTRIC

EXHIBIT 1

SUMMARY OF COMPANY DATA

| | | |
|---|---|---|
| ANNUAL PEAK | 2,051 | MW |
| ANNUAL SYSTEM INPUT | 8,831,456 | MWH |
| ANNUAL SALES | 8,289,331 | MWH |
| SYSTEM LOSSES @ INPUT | 542,125 | or 6.14% |
| SYSTEM LOAD FACTOR | 49.2% | |

SUMMARY OF LOSSES - OUTPUT RESULTS

| SERVICE | KV | --- MW --- | Input | % TOTAL | --- MWH --- | Input | % TOTAL |
|---|---|---|---|---|---|---|---|
| TRANS | 500,345,115 | 51.1 | 2.49% | 35.39% | 220,862 | 2.50% | 40.74% |
| SUBTRANS | 69 | 7.4 | 0.36% | 5.15% | 23,314 | 0.26% | 4.30% |
| PRIMARY | 35,12,1 | 55.3 | 2.69% | 38.25% | 136,001 | 1.54% | 25.09% |
| SECONDARY | 120/240,to,477 | 30.7 | 1.49% | 21.22% | 161,948 | 1.83% | 29.87% |
| TOTAL | | 144.5 | 7.04% | 100.00% | 542,125 | 6.14% | 100.00% |

SUMMARY OF LOSS FACTORS

| | | CUMMULATIVE SALES EXPANSION FACTORS | | | |
|---|---|---|---|---|---|
| SERVICE | KV | DEMAND (Peak) | | ENERGY (Annual) | |
| | | d | 1/d | e | 1/e |
| TOT TRANS | 500,345,115 | 1.02557 | 0.97507 | 1.02565 | 0.97499 |
| SUBTRAN | 69 | 1.02941 | 0.97143 | 1.02850 | 0.97229 |
| PRIMARY | 35,12,1 | 1.06117 | 0.94236 | 1.04670 | 0.95539 |
| SECONDARY | 120/240,to,477 | 1.08208 | 0.92415 | 1.07403 | 0.93107 |

EL PASO ELECTRIC 2021 LOSS ANALYSIS

**SUMMARY OF CONDUCTOR INFORMATION**

| DESCRIPTION | | | | | CIRCUIT MILES | LOADING % RATING | MW LOSSES LOAD | MW LOSSES NO LOAD | MW LOSSES TOTAL | MWH LOSSES LOAD | MWH LOSSES NO LOAD | MWH LOSSES TOTAL |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| --- BULK ----------- | 345 KV | OR GREATER | | | | | | | | | | |
| TIE LINES | | | | | 0.0 | 0.00% | 0.000 | 0.000 | 0.000 | 0 | 0 | 0 |
| BULK TRANS | | | | | 0.0 | 0.00% | 0.000 | 0.000 | 0.000 | 0 | 0 | 0 |
| SUBTOT | | | | | 0.0 | | 0.000 | 0.000 | 0.000 | 0 | 0 | 0 |
| --- TRANS --------- | 80 KV | TO | 345.00 | KV | | | | | | | | |
| TIE LINES | | | | | 0 | 0.00% | 0.000 | 0.000 | 0.000 | 0 | 0 | 0 |
| TRANS1 | 115 KV | | | | 0.0 | 0.00% | 0.000 | 0.000 | 0.000 | 0 | 0 | 0 |
| TRANS2 | 80 KV | | | | 0.0 | 0.00% | 0.000 | 0.001 | 0.001 | 0 | 8 | 8 |
| SUBTOT | | | | | 0.0 | | 0.000 | 0.001 | 0.001 | 0 | 8 | 8 |
| --- SUBTRANS ------ | 35 KV | TO | 80 | KV | | | | | | | | |
| TIE LINES | | | | | 0 | 0.00% | 0.000 | 0.000 | 0.000 | 0 | 0 | 0 |
| SUBTRANS1 | 69 KV | | | | 0.0 | 0.00% | 0.000 | 0.000 | 0.000 | 0 | 0 | 0 |
| SUBTRANS2 | 60 KV | | | | 0.0 | 0.00% | 0.000 | 0.000 | 0.000 | 0 | 0 | 0 |
| SUBTRANS3 | 35 KV | | | | 0.0 | 0.00% | 0.000 | 0.000 | 0.000 | 0 | 0 | 0 |
| SUBTOT | | | | | 0.0 | | 0.000 | 0.000 | 0.000 | 0 | 0 | 0 |
| PRIMARY LINES | | | | | 8,123 | | 44.816 | 0.285 | 45.100 | 89,131 | 2,493 | 91,625 |
| SECONDARY LINES | | | | | 2,865 | | 1.639 | 0.000 | 1.639 | 3,004 | 0 | 3,004 |
| SERVICES | | | | | 7,500 | | 5.649 | 0.925 | 6.574 | 11,696 | 8,098 | 19,794 |
| TOTAL | | | | | 18,488 | | 52.103 | 1.210 | 53.314 | 103,831 | 10,599 | 114,431 |

## SUMMARY OF TRANSFORMER INFORMATION

| DESCRIPTION | | KV VOLTAGE | CAPACITY MVA | NUMBER TRANSFMR | AVERAGE SIZE | LOADING % | MVA LOAD | MW LOSSES LOAD | MW LOSSES NO LOAD | MW LOSSES TOTAL | MWH LOSSES LOAD | MWH LOSSES NO LOAD | MWH LOSSES TOTAL |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| BULK STEP-UP | | 345 | 0.0 | 0 | 0.0 | 0.00% | 0 | 0.000 | 0.000 | 0.000 | 0 | 0 | 0 |
| BULK - BULK | | | 0.0 | 0 | 0.0 | 0.00% | 0 | 0.000 | 0.000 | 0.000 | 0 | 0 | 0 |
| BULK - TRANS1 | | 115 | 0.0 | 0 | 0.0 | 0.00% | 0 | 0.000 | 0.000 | 0.000 | 0 | 0 | 0 |
| BULK - TRANS2 | | 80 | 0.0 | 0 | 0.0 | 0.00% | 0 | 0.000 | 0.000 | 0.000 | 0 | 0 | 0 |
| TRANS1 STEP-UP | | 115 | 0.0 | 0 | 0.0 | 0.00% | 0 | 0.000 | 0.000 | 0.000 | 0 | 0 | 0 |
| TRANS1 - TRANS2 | | 80 | 0.0 | 0 | 0.0 | 0.00% | 0 | 0.000 | 0.000 | 0.000 | 0 | 0 | 0 |
| TRANS1-SUBTRANS1 | | 69 | 0.0 | 0 | 0.0 | 0.00% | 0 | 0.000 | 0.000 | 0.000 | 0 | 0 | 0 |
| TRANS1-SUBTRANS2 | | 60 | 0.0 | 0 | 0.0 | 0.00% | 0 | 0.000 | 0.000 | 0.000 | 0 | 0 | 0 |
| TRANS1-SUBTRANS3 | | 35 | 0.0 | 0 | 0.0 | 0.00% | 0 | 0.000 | 0.000 | 0.000 | 0 | 0 | 0 |
| TRANS2 STEP-UP | | 80 | 0.0 | 0 | 0.0 | 0.00% | 0 | 0.000 | 0.000 | 0.000 | 0 | 0 | 0 |
| TRANS2-SUBTRANS1 | | 69 | 0.0 | 0 | 0.0 | 0.00% | 0 | 0.000 | 0.000 | 0.000 | 0 | 0 | 0 |
| TRANS2-SUBTRANS2 | | 60 | 0.0 | 0 | 0.0 | 0.00% | 0 | 0.000 | 0.000 | 0.000 | 0 | 0 | 0 |
| TRANS2-SUBTRANS3 | | 35 | 0.0 | 0 | 0.0 | 0.00% | 0 | 0.000 | 0.000 | 0.000 | 0 | 0 | 0 |
| SUBTRAN1 STEP-UP | | 69 | 0.0 | 0 | 0.0 | 0.00% | 0 | 0.000 | 0.000 | 0.000 | 0 | 0 | 0 |
| SUBTRAN2 STEP-UP | | 60 | 0.0 | 0 | 0.0 | 0.00% | 0 | 0.000 | 0.001 | 0.001 | 0 | 0 | 0 |
| SUBTRAN3 STEP-UP | | 35 | 0.0 | 0 | 0.0 | 0.00% | 0 | 0.000 | 0.000 | 0.000 | 0 | 0 | 0 |
| SUBTRAN1-SUBTRAN2 | | 60 | 0.0 | 0 | 0.0 | 0.00% | 0 | 0.000 | 0.000 | 0.000 | 0 | 0 | 0 |
| SUBTRAN1-SUBTRAN3 | | 35 | 0.0 | 0 | 0.0 | 0.00% | 0 | 0.000 | 0.000 | 0.000 | 0 | 0 | 0 |
| SUBTRAN2-SUBTRAN3 | | 35 | 0.0 | 0 | 0.0 | 0.00% | 0 | 0.000 | 0.000 | 0.000 | 0 | 0 | 0 |
| DISTRIBUTION SUBSTATIONS | | | | | | | | | | | | | |
| TRANS1 - | 115 | 23 | 891.0 | 23 | 38.7 | 58.62% | 522 | 1.244 | 1.444 | 2.687 | 3,412 | 12,646 | 16,058 |
| TRANS1 - | 115 | 12 | 1,518.6 | 44 | 34.5 | 51.76% | 786 | 3.512 | 1.489 | 5.000 | 9,333 | 13,041 | 22,374 |
| TRANS1 - | 115 | 1 | 12.8 | 1 | 12.8 | 15.94% | 2 | 0.101 | 0.083 | 0.183 | 258 | 723 | 981 |
| TRANS2 - | 80 | 23 | 0.0 | 0 | 0.0 | 0.00% | 0 | 0.000 | 0.000 | 0.000 | 0 | 0 | 0 |
| TRANS2 - | 80 | 12 | 0.0 | 0 | 0.0 | 0.00% | 0 | 0.000 | 0.000 | 0.000 | 0 | 0 | 0 |
| TRANS2 - | 80 | 1 | 0.0 | 0 | 0.0 | 0.00% | 0 | 0.000 | 0.000 | 0.000 | 0 | 0 | 0 |
| SUBTRAN1- | 69 | 23 | 95.6 | 4 | 23.9 | 19.21% | 18 | 0.025 | 0.049 | 0.074 | 72 | 426 | 498 |
| SUBTRAN1- | 69 | 12 | 656.6 | 21 | 31.3 | 49.46% | 325 | 1.520 | 0.808 | 2.328 | 4,034 | 7,080 | 11,113 |
| SUBTRAN1- | 69 | 1 | 50.1 | 5 | 10.0 | 53.97% | 27 | 0.103 | 0.086 | 0.189 | 276 | 751 | 1,027 |
| SUBTRAN2- | 60 | 23 | 0.0 | 0 | 0.0 | 0.00% | 0 | 0.000 | 0.000 | 0.000 | 0 | 0 | 0 |
| SUBTRAN2- | 60 | 12 | 0.0 | 0 | 0.0 | 0.00% | 0 | 0.000 | 0.000 | 0.000 | 0 | 0 | 0 |
| SUBTRAN2- | 60 | 1 | 0.0 | 0 | 0.0 | 0.00% | 0 | 0.000 | 0.000 | 0.000 | 0 | 0 | 0 |
| SUBTRAN3- | 35 | 23 | 0.0 | 0 | 0.0 | 0.00% | 0 | 0.000 | 0.000 | 0.000 | 0 | 0 | 0 |
| SUBTRAN3- | 35 | 12 | 0.0 | 0 | 0.0 | 0.00% | 0 | 0.000 | 0.000 | 0.000 | 0 | 0 | 0 |
| SUBTRAN3- | 35 | 1 | 0.0 | 0 | 0.0 | 0.00% | 0 | 0.000 | 0.000 | 0.000 | 0 | 0 | 0 |
| PRIMARY - PRIMARY | | | 134.6 | 140 | 1.0 | 38.00% | 51 | 0.147 | 0.279 | 0.426 | 377 | 2,441 | 2,817 |
| LINE TRANSFRMR | | | 5,643.2 | 99,400 | 56.8 | 32.63% | 1,841 | 6.971 | 15.722 | 22.692 | 11,015 | 137,722 | 148,737 |
| | | | =========== | =========== | =========== | =========== | | =========== | =========== | =========== | =========== | ========= | =========== |
| TOTAL | | | 9,003 | 99,638 | | | | 13.622 | 19.958 | 33.580 | 28,777 | 174,828 | 203,605 |

**SUMMARY OF LOSSES DIAGRAM - DEMAND MODEL - SYSTEM PEAK** 2051 MW

BULK TIE LINES
LOAD 0.00% MW
LOAD LOSS 0.000 MW
NOLD LOSS 0.000 MW

BULK LINES
LOADING 0.00%
LOAD LOSS 0.000 MW
NOLD LOSS 0.000 MW

BULK STEP UP
LOADING 0.00%
NO LOAD 0.000 MW
LOAD 0.000 MW
AVG SIZE 0 MVA
NUMBER 0

BULK-BULK
LOADING 0.00%
NO LOAD 0 MW
LOAD 0 MW
AVG SIZE 0 MVA
NUMBER 0

TRANS TIE LINES
LOAD 0.00% MW
LOAD LOSS 0.000 MW
NOLD LOSS 0.000 MW

BULK-TRANS1 STEP DOWN
LOADING 0.00%
NO LOAD 0.000 MW
LOAD 0.000 MW
AVG SIZE 0 MVA
NUMBER 0

TRAN1-TRAN2 STEP DOWN
LOADING 0.00%
NO LOAD 0.000 MW
LOAD 0.000 MW
AVG SIZE 0 MVA
NUMBER 0

BULK-TRANS2 STEP DOWN
LOADING 0.00%
NO LOAD 0.000 MW
LOAD 0.000 MW
AVG SIZE 0 MVA
NUMBER 0

TRANS 1&2 STEP UPS
LDNG TR1SU 0.00%
NOLOAD1&2 0.000 MW
LOAD 1&2 0.000 MW
AVSIZ TR1SU 0.0 MVA
NUMBER 0

TRANS1 115.0 KV
LOADING 0.00%
LOAD LOSS 0.000 MW
NOLD LOSS 0.000 MW

TRANS2 80.0 KV
LOADING 0.00%
LOAD LOSS 0.000 MW
NOLD LOSS 0.001 MW

TRANS CUST
SUBS 0.000 MW
0.000 MVA
LINES MW
MVA

SUBTRANS TIE LINES
LOAD 0.00% MW
LOAD LOSS 0.000 MW
NOLD LOSS 0.000 MW

TRANS1&2-SUBTRANS1
LDNG TR2-ST 0.00%
NO LOAD 0.000 MW
LOAD 0.000 MW
AVSIZ TR2 0 MVA
NUMBER 0

SUBTR1&2-SUBTRANS2&3
LOADING 0.00%
NO LOAD 0.000 MW
LOAD 0.000 MW
AVG SIZE 0 MVA
NUMBER 0

TRANS1&2- SUBTRANS2
LDNG TR2-ST: 0.00%
NO LOAD 0.000 MW
LOAD 0.000 MW
AVSIZ TR2-ST 0.00 MVA
NUMBER 0

TRANS1&2-SUBTRANS3
LDNG TR2-ST2 0.00%
NO LOAD 0.00
LOAD 0.00
AVSIZ TR2-ST2 0.00
NUMBER 0

SUBTRANS1,2,&3 STEP UPS
LDNG ST1SU 0.00%
NO LOAD 0.001 MW
LOAD 0.000 MW
AVSIZ ST2 0.0 MVA
NUMBER 0

SUBTRANS1 69 KV
LOADING 0.00%
LOAD LOSS 0.000 MW
NOLD LOSS 0.000 MW

SUBTRANS2 60 KV
LOADING 0.00%
LOAD LOSS 0.000 MW
NOLD LOSS 0.000 MW

SUBTRANS2 35 KV
LOADING 0.00%
LOAD LOSS 0.000 MW
NOLD LOSS 0.000 MW

SUBTRANS CUST
SUBS - MW 0.000
MVA 0.000
LINES- MW
MVA

TO DISTRIBUTION SYSTEM
TOTAL 1680.6 MVA 1646.9 MW

TRANS1 1,310.4 MVA
77.97%
115 KV

TRANS2 0.0 MVA
0.00%
80 KV

SUBTRANS1 370.1 MVA
22.03%
69 KV

SUBTRANS2 0.0 MVA
0.00%
60 KV

SUBTRANS3 0.0 MVA
0.00%
35 KV

FROM HIGH VOLTAGE SYSTEM

TOTAL 1,681 MVA 1,647 MW

| TRANS1 | TRANS2 | SUBTRANS1 | SUBTRANS2 | SUBTRANS3 |
|---|---|---|---|---|
| 1,310.4 MVA | 0.0 MVA | 370.1 MVA | 0.0 MVA | 0.0 MVA |
| 77.97% | 0.00% | 22.03% | 0.00% | 0.00% |
| 115 KV | 80 KV | 69 KV | 60 KV | 35 KV |

DISTRIBUTION SYSTEM LOAD

| | PRIM1 | PRIM2 | PRIM3 | PRIM1 | PRIM2 | PRIM3 | PRIM1 | PRIM2 | PRIM3 | PRIM1 | PRIM2 | PRIM3 | PRIM1 | PRIM2 | PRIM3 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| VOLTAGE | 23 | 12 | 1 | 23 | 12 | 1 | 23 | 12 | 1 | 23 | 12 | 1 | 23 | 12 | 1 |
| LOAD MVA | 522 | 786 | 2 | 0 | 0 | 0 | 16 | 325 | 27 | 0 | 0 | 0 | 0 | 0 | 0 |
| % SYS TOT | 31.08% | 46.77% | 0.12% | 0.00% | 0.00% | 0.00% | 1.09% | 19.32% | 1.61% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% |
| NOLD LOSS | 1.444 | 1.469 | 0.083 | 0.000 | 0.000 | 0.000 | 0.049 | 0.608 | 0.066 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 |
| LOAD LOSS | 1.244 | 3.512 | 0.101 | 0.000 | 0.000 | 0.000 | 0.025 | 1.520 | 0.103 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 |
| AVG SIZE | 38.7 | 34.5 | 12.6 | 0.0 | 0.0 | 0.0 | 23.9 | 31.3 | 10.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| NUMBER | 23 | 44 | 1 | 0 | 0 | 0 | 4 | 21 | 5 | 0 | 0 | 0 | 0 | 0 | 0 |
| DIVERSITY RATIO | 1.000 | 1.000 | 1.000 | 0.000 | 0.000 | 0.000 | 1.000 | 1.000 | 1.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 |

PRIMARY LINES
LOADING 1793.340 MW
@ SYS PF 1629.939 MVA
LOAD LOSS 44.816 MW
NOLD LOSS 0.285 MW
TOT LOSS 45.100 MW

PRIM/PRIM TRANSF
LOADING 51.146 MW
NOLD LOSS 0.279 MW
LOAD LOSS 0.147 MW
AVG SIZE 0.96
NUMBER 140

PRIM CUST LOADS
NO LINES 0.000 MW
CUST SUB 0.000 MVA
NO LINES 13.500 MW
CO. SUB 13.776 MVA
PRIM WITH 66.100 MW
LINES 71.846 MVA

LINE TRANSFORMERS
LOADING 1681.714 MW MVA 1863.958
NOLD LOSS 15.722 MW
LOAD LOSS 6.971 MW
AVG SIZE 56.6 KVA
NUMBER 99400

SECONDARY LINES
LOAD 416.926 MW
LOAD LOSS 1.639 MW
NOLD LOSS 0.000 MW
TOT LOSS 1.639 MW

NO SECONDARY LINES
LOAD 1242.093 MW

SERVICES
LOAD 1657.383 MW
LOAD LOSS 5.649 MW
NOLD LOSS 0.925 MW
TOT LOSS 6.574 MW

CUSTOMER SECONDARY LOAD
1650.809 MW

**SUMMARY of SALES and CALCULATED LOSSES**

| LOSS # AND LEVEL | MW LOAD | NO LOAD + | LOAD = | TOT LOSS | EXP FACTOR | CUM EXP FAC | MWH LOAD | NO LOAD + | LOAD = | TOT LOSS | EXP FACTOR | CUM EXP FAC |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 BULK XFMMR | 0.0 | 0.00 | 0.00 | 0.00 | 0.000000 | 0.000000 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2 BULK LINES | 0.0 | 0.00 | 0.00 | 0.00 | 0.000000 | 0.000000 | 0 | 0 | 0 | 0 | 0.0000000 | 0.0000000 |
| 3 TRANS1 XFMR | 0.0 | 0.00 | 0.00 | 0.00 | 0.000000 | 0.000000 | 0 | 0 | 0 | 0 | 0.0000000 | 0.0000000 |
| 4 TRANS1 LINES | 0.0 | 0.00 | 0.00 | 0.00 | 0.000000 | 0.000000 | 0 | 0 | 0 | 0 | 0.0000000 | 0.0000000 |
| 5 TRANS2TR1 SD | 0.0 | 0.00 | 0.00 | 0.00 | 0.000000 | 0.000000 | 0 | 0 | 0 | 0 | 0.0000000 | 0.0000000 |
| 6 TRANS2BLK SD | 0.0 | 0.00 | 0.00 | 0.00 | 0.000000 | 0.000000 | 0 | 0 | 0 | 0 | 0.0000000 | 0.0000000 |
| 7 TRANS2 LINES | 0.0 | 0.00 | 0.00 | 0.00 | 0.000000 | 0.000000 | 0 | 8 | 0 | 8 | 0.0000000 | 0.0000000 |
| 115 kV > TOTAL TRAN | 2,051.0 | 7.67 | 43.47 | 51.14 | 1.025570 | 1.025570 | 8,831,456 | 67,193 | 153,668 | 220,862 | 1.0256500 | 1.0256500 |
| 8 STR1BLK SD | | | | | | | | | | | | |
| 9 STR1T1 SD | 0.0 | 0.00 | 0.00 | 0.00 | 0.000000 | 0.000000 | 0 | 0 | 0 | 0 | 0.0000000 | 0.0000000 |
| 10 SRT1T2 SD | 0.0 | 0.00 | 0.00 | 0.00 | 0.000000 | 0.000000 | 0 | 0 | 0 | 0 | 0.0000000 | 0.0000000 |
| 11 SUBTRANS1 LINES | 355.0 | 1.12 | 6.32 | 7.44 | 1.021400 | 1.029410 | 1,667,446 | 9,773 | 13,540 | 23,314 | 1.0141800 | 1.0285000 |
| 12 STR2T1 SD | 0.0 | 0.00 | 0.00 | 0.00 | 0.000000 | 0.000000 | 0 | 0 | 0 | 0 | 0.0000000 | 0.0000000 |
| 13 STR2T2 SD | 0.0 | 0.00 | 0.00 | 0.00 | 0.000000 | 0.000000 | 0 | 0 | 0 | 0 | 0.0000000 | 0.0000000 |
| 14 STR2S1 SD | 0.0 | 0.00 | 0.00 | 0.00 | 0.000000 | 0.000000 | 0 | 0 | 0 | 0 | 0.0000000 | 0.0000000 |
| 15 SUBTRANS2 LINES | 0.0 | 0.00 | 0.00 | 0.00 | 0.000000 | 0.000000 | 0 | 0 | 0 | 0 | 0.0000000 | 0.0000000 |
| 16 STR3T1 SD | 0.0 | 0.00 | 0.00 | 0.00 | 0.000000 | 0.000000 | 0 | 0 | 0 | 0 | 0.0000000 | 0.0000000 |
| 17 STR3T2 SD | 0.0 | 0.00 | 0.00 | 0.00 | 0.000000 | 0.000000 | 0 | 0 | 0 | 0 | 0.0000000 | 0.0000000 |
| 18 STR3S1 SD | 0.0 | 0.00 | 0.00 | 0.00 | 0.000000 | 0.000000 | 0 | 0 | 0 | 0 | 0.0000000 | 0.0000000 |
| 19 STR3S2 SD | 0.0 | 0.00 | 0.00 | 0.00 | 0.000000 | 0.000000 | 0 | 0 | 0 | 0 | 0.0000000 | 0.0000000 |
| 20 SUBTRANS3 LINES | 0.0 | 0.00 | 0.00 | 0.00 | 0.000000 | 0.000000 | 0 | 0 | 0 | 0 | 0.0000000 | 0.0000000 |
| 21 SUBTRANS TOTAL | 355.0 | 1.12 | 6.32 | 7.44 | 1.021400 | 1.029410 | 1,667,446 | 9,773 | 13,540 | 23,314 | 1.0141800 | 1.0285000 |
| DISTRIBUTION SUBST | | | | | | | | | | | | |
| TRANS1 | 1,284.2 | 3.01 | 4.86 | 7.87 | 1.006166 | 1.031894 | 5,816,039 | 26,409 | 13,003 | 39,412 | 1.0068227 | 1.0326477 |
| TRANS2 | 0.0 | 0.00 | 0.00 | 0.00 | 0.000000 | 0.000000 | 0 | 0 | 0 | 0 | 0.0000000 | 0.0000000 |
| SUBTR1 | 362.7 | 0.94 | 1.65 | 2.59 | 1.007194 | 1.036816 | 1,642,832 | 8,257 | 4,382 | 12,639 | 1.0077529 | 1.0364738 |
| SUBTR2 | 0.0 | 0.00 | 0.00 | 0.00 | 0.000000 | 0.000000 | 0 | 0 | 0 | 0 | 0.0000000 | 0.0000000 |
| SUBTR3 | 0.0 | 0.00 | 0.00 | 0.00 | 0.000000 | 0.000000 | 0 | 0 | 0 | 0 | 0.0000000 | 0.0000000 |
| WEIGHTED AVERAGE | 1,646.9 | 3.96 | 6.50 | 10.46 | 1.006393 | 1.032978 | 7,458,871 | 34,666 | 17,385 | 52,051 | 1.0070274 | 1.0334904 |
| PRIMARY INTRCHNGE | 0.0 | | | | 0.000000 | | 0 | | | | 0.0000000 | |
| PRIMARY LINES | 1,793.1 | 0.28 | 44.96 | 45.25 | 1.025888 | 1.059720 | 7,324,633 | 2,493 | 89,508 | 92,001 | 1.0127203 | 1.0466367 |
| LINE TRANSF | 1,681.7 | 15.72 | 6.97 | 22.69 | 1.013678 | 1.074215 | 6,770,811 | 137,722 | 11,015 | 148,737 | 1.0224608 | 1.0701450 |
| SECONDARY | 1,659.0 | 0.00 | 1.64 | 1.64 | 1.000989 | 1.075277 | 6,622,074 | 0 | 3,004 | 3,004 | 1.0004539 | 1.0706307 |
| SERVICES | 1,657.4 | 0.92 | 5.65 | 6.57 | 1.003982 | 1.079559 | 6,619,070 | 8,098 | 11,696 | 19,794 | 1.0029994 | 1.0738419 |
| | | =========== | =========== | =========== | | | | =========== | =========== | =========== | | |
| TOTAL SYSTEM | | 29.67 | 115.51 | 145.19 | | | | 259,945 | 299,817 | 559,763 | | |

**DEVELOPMENT of LOSS FACTORS**
UNADJUSTED
DEMAND

| LOSS FACTOR LEVEL | CUSTOMER SALES MW a | CALC LOSS TO LEVEL b | SALES MW @ GEN c | CUM PEAK EXPANSION FACTORS d | 1/d |
|---|---|---|---|---|---|
| BULK LINES | 0.0 | 0.0 | 0.0 | 0.00000 | 0.00000 |
| TRANS SUBS | 0.0 | 0.0 | 0.0 | 0.00000 | 0.00000 |
| TRANS LINES | 176.1 | 4.5 | 180.6 | 1.02557 | 0.97507 |
| TOTAL TRANS | 0.0 | 0.0 | 0.0 | 0.00000 | 0.00000 |
| SUBTRANS | 0.0 | 0.0 | 0.0 | 1.02941 | 0.97143 |
| PRIM SUBS | 13.5 | 0.4 | 13.9 | 1.03298 | 0.96807 |
| PRIM LINES | 66.1 | 3.9 | 70.0 | 1.05972 | 0.94365 |
| SECONDARY | 1,650.8 | 131.3 | 1,782.1 | 1.07956 | 0.92630 |
| TOTALS | 1,906.5 | 140.2 | 2,046.7 | | |

DEVELOPMENT of LOSS FACTORS
UNADJUSTED
ENERGY

| LOSS FACTOR LEVEL | CUSTOMER SALES MWH a | CALC LOSS TO LEVEL b | SALES MWH @ GEN c | CUM ANNUAL EXPANSION FACTORS d | 1/d |
|---|---|---|---|---|---|
| BULK LINES | 0 | 0 | 0 | 0.00000 | 0.00000 |
| TRANS SUBS | 0 | 0 | 0 | 0.00000 | 0.00000 |
| TRANS LINES | 1,162,097 | 29,808 | 1,191,905 | 1.02565 | 0.97499 |
| TOTAL TRANS | 0 | 0 | 0 | 0.00000 | 0.00000 |
| SUBTRANS | 0 | 0 | 0 | 1.02850 | 0.97229 |
| PRIM SUBS | 66,137 | 2,215 | 68,352 | 1.03349 | 0.96759 |
| PRIM LINES | 461,821 | 21,538 | 483,359 | 1.04664 | 0.95544 |
| SECONDARY | 6,599,276 | 487,303 | 7,086,579 | 1.07384 | 0.93124 |
| TOTALS | 8,289,331 | 540,864 | 8,830,195 | | |

ESTIMATED VALUES AT GENERATION

| LOSS FACTOR AT VOLTAGE LEVEL | MW | MWH |
|---|---|---|
| BULK LINES | 0.00 | 0 |
| TRANS SUBS | 0.00 | 0 |
| TRANS LINES | 180.60 | 1,191,905 |
| SUBTRANS SUBS | 0.00 | 0 |
| SUBTRANS LINES | 0.00 | 0 |
| PRIM SUBS | 13.95 | 68,352 |
| PRIM LINES | 70.05 | 483,359 |
| SECONDARY | 1,782.15 | 7,086,579 |
| SUBTOTAL | 2,046.74 | 8,830,195 |
| ACTUAL ENERGY | 2,051.00 | 8,831,456 |
| MISMATCH | (4.26) | (1,261) |
| % MISSMATCH | -0.21% | -0.01% |

**DEVELOPMENT of LOSS FACTORS**
ADJUSTED
DEMAND

| LOSS FACTOR LEVEL | CUSTOMER SALES MW | SALES ADJUST | CALC LOSS TO LEVEL | SALES MW @ GEN | CUM PEAK EXPANSION FACTORS | |
|---|---|---|---|---|---|---|
| | a | b | c | d | e | f=1/e |
| BULK LINES | 0.0 | 0.0 | 0.0 | 0.0 | 0.00000 | 0.00000 |
| TRANS SUBS | 0.0 | 0.0 | 0.0 | 0.0 | 0.00000 | 0.00000 |
| TRANS LINES | 176.1 | 0.0 | 4.5 | 180.6 | 1.02557 | 0.97507 |
| TOTAL TRANS | 0.0 | 0.0 | 0.0 | 0.0 | 0.00000 | 0.00000 |
| SUBTRANS | 0.0 | 0.0 | 0.0 | 0.0 | 1.02941 | 0.97143 |
| PRIM SUBS | 13.5 | 0.0 | 0.4 | 13.9 | 1.03298 | 0.96807 |
| PRIM LINES | 66.1 | 0.0 | 4.0 | 70.1 | 1.06117 | 0.94236 |
| SECONDARY | 1,650.8 | 0.0 | 135.5 | 1,786.3 | 1.08208 | 0.92415 |
| | | | 144.5 | | | |
| TOTALS | 1,906.5 | 0.0 | 144.5 | 2,051.0 | 1.07579 <COMPOSITE | |

DEVELOPMENT of LOSS FACTORS
ADJUSTED
ENERGY

| LOSS FACTOR LEVEL | CUSTOMER SALES MWH | SALES ADJUST | CALC LOSS TO LEVEL | SALES MWH @ GEN | CUM ANNUAL EXPANSION FACTORS | |
|---|---|---|---|---|---|---|
| | a | b | c | d | e | f=1/e |
| BULK LINES | 0 | 0 | 0 | 0 | 0.00000 | 0.00000 |
| TRANS SUBS | 0 | 0 | 0 | 0 | 0.00000 | 0.00000 |
| TRANS LINES | 1,162,097 | 0 | 29,808 | 1,191,905 | 1.02565 | 0.97499 |
| TOTAL TRANS | 0 | 0 | 0 | 0 | 0.00000 | 0.00000 |
| SUBTRANS | 0 | 0 | 0 | 0 | 1.02850 | 0.97229 |
| PRIM SUBS | 66,137 | 0 | 2,215 | 68,352 | 1.03349 | 0.96759 |
| PRIM LINES | 461,821 | 0 | 21,566 | 483,387 | 1.04670 | 0.95539 |
| SECONDARY | 6,599,276 | 0 | 488,536 | 7,087,812 | 1.07403 | 0.93107 |
| | | | 542,125 | | | |
| TOTALS | 8,289,331 | 0 | 542,125 | 8,831,456 | 1.06540 <COMPOSITE | |

ESTIMATED VALUES AT GENERATION

| LOSS FACTOR AT VOLTAGE LEVEL | MW | MWH |
|---|---|---|
| BULK LINES | 0.00 | 0 |
| TRANS SUBS | 0.00 | 0 |
| TRANS LINES | 180.60 | 1,191,905 |
| SUBTRANS SUBS | 0.00 | 0 |
| SUBTRANS LINES | 0.00 | 0 |
| PRIM SUBS | 13.95 | 68,352 |
| PRIM LINES | 70.14 | 483,387 |
| SECONDARY | 1,786.31 | 7,087,812 |
| | 2,051.00 | 8,831,456 |
| ACTUAL ENERGY | 2,051.00 | 8,831,456 |
| MISMATCH | 0.00 | 0 |
| % MISSMATCH | 0.00% | 0.00% |

**Adjusted Losses and Loss Factors by Facility** EXHIBIT 8

**Unadjusted Losses by Segment**

| | MW | Unadjusted | MWH | Unadjusted |
|---|---|---|---|---|
| Service Drop Losses | 6.57 | 6.20 | 19,794 | 18,608 |
| Secondary Losses | 1.64 | 1.54 | 3,004 | 2,825 |
| Line Transformer Losses | 22.69 | 21.39 | 148,737 | 139,830 |
| Primary Line Losses | 45.25 | 42.66 | 92,001 | 86,492 |
| Distribution Substation Losses | 10.46 | 9.86 | 52,051 | 48,934 |
| Subtransmission Losses | 7.44 | 7.44 | 23,314 | 23,314 |
| Transmission System Losses | 51.14 | 51.14 | 220,862 | 220,862 |
| Total | 145.19 | 140.23 | 559,763 | 540,864 |

**Mismatch Allocation by Segment**

| | MW | MWH |
|---|---|---|
| Service Drop Losses | -0.32 | -79 |
| Secondary Losses | -0.08 | -12 |
| Line Transformer Losses | -1.12 | -594 |
| Primary Line Losses | -2.22 | -368 |
| Distribution Substation Losses | -0.51 | -208 |
| Subtransmission Losses | 0.00 | 0 |
| Transmission System Losses | 0.00 | 0 |
| Total | -4.26 | -1,261 |

**Adjusted Losses by Segment**

| | MW | % of Total | MWH | % of Total |
|---|---|---|---|---|
| Service Drop Losses | 6.52 | 4.5% | 18,687 | 3.4% |
| Secondary Losses | 1.63 | 1.1% | 2,837 | 0.5% |
| Line Transformer Losses | 22.51 | 15.6% | 140,424 | 25.9% |
| Primary Line Losses | 44.88 | 31.1% | 86,859 | 16.0% |
| Distribution Substation Losses | 10.38 | 7.2% | 49,142 | 9.1% |
| Subtransmission Losses | 7.44 | 5.1% | 23,314 | 4.3% |
| Transmission System Losses | 51.14 | 35.4% | 220,862 | 40.7% |
| Total | 144.49 | 100.0% | 542,125 | 100.0% |

| **Loss Factors by Segment** | **MW** | **MWH** |
|---|---|---|
| Retail Sales from Service Drops | 1650.81 | 6,599,276 |
| Adjusted Service Drop Losses | 6.52 | 18,687 |
| Input to Service Drops | 1657.33 | 6,617,963 |
| **Service Drop Loss Factor** | **1.00395** | **1.00283** |
| | | |
| Output from Secondary | 1657.33 | 6,617,963 |
| Adjusted Secondary Losses | 1.63 | 2,837 |
| Input to Secondary | 1658.96 | 6,620,800 |
| **Secondary Conductor Loss Factor** | **1.00098** | **1.00043** |
| | | |
| Output from Line Transformers | 1658.96 | 6,620,800 |
| Adjusted Line Transformer Losses | 22.51 | 140,424 |
| Input to Line Transformers | 1681.47 | 6,761,224 |
| **Line Transformer Loss Factor** | **1.01357** | **1.02121** |
| **Secondary Composite** | 1.01857 | 1.02454 |
| Retail Sales from Primary | 66.10 | 461,821 |
| Req. Whls Sales from Primary | 0.00 | 0 |
| Input to Line Transformers | 1681.47 | 6,761,224 |
| Output from Primary Lines | 1747.57 | 7,223,045 |
| Adjusted Primary Line Losses | 44.88 | 86,859 |
| Input to Primary Lines | 1792.45 | 7,309,904 |
| **Primary Line Loss Factor** | **1.02568** | **1.01203** |
| | | |
| Output Pl from Distribution Substations | 1792.45 | 7,309,904 |
| Req. Whls Sales from Substations | 0.00 | 0 |
| Retail Sales from Substations | 13.50 | 66,137 |
| TotalOutput from Distribution Substations | 1805.95 | 7,376,041 |
| Adjusted Distribution Substation Losses | 10.38 | 49,142 |
| Input to Distribution Substations | 1816.33 | 7,425,183 |
| **Distribution Substation Loss Factor** | **1.00575** | **1.00666** |
| FROM SUBTRANS | 347.27 | 1,594,985 |
| Retail Sales at from SubTransmission | 0.00 | 0 |
| Req. Whls Sales from SubTransmission | 0.00 | 0 |
| Input to Distribution Substations | 347.27 | 1,644,127 |
| Output from SubTransmission | 347.27 | 1,644,127 |
| Adjusted SubTransmission System Losses | 7.44 | 23,314 |
| Input to SubTransmission | 354.71 | 1,667,441 |
| **SubTransmission Loss Factor** | **1.02142** | **1.01418** |
| FROM TRANS TO DIST SUBS | 0.00 | 0 |
| Retail Sales at from Transmission | 162.60 | 1,100,941 |
| Req. Whls Sales from Transmission | 13.50 | 61,156 |
| Input Subtransmission | 354.71 | 1,667,441 |
| Output from Transmission | 1999.86 | 8,610,594 |
| Adjusted Transmission System Losses | 51.14 | 220,862 |
| Input to Transmission | 2051.00 | 8,831,456 |
| **Transmission Loss Factor** | **1.02557** | **1.02565** |

**DEMAND MW** **SUMMARY OF LOSSES AND LOSS FACTORS BY DELIVERY VOLTAGE** **EXHIBIT 9**
PAGE 1 of 2

| | SERVICE LEVEL | | SALES MW | LOSSES | SECONDARY | PRIMARY | SUBSTATION | SUBTRANS | TRANSMISSION |
|---|---|---|---|---|---|---|---|---|---|
| 1 | **SERVICES** | | | | | | | | |
| 2 | SALES | | 1,650.81 | | 1,650.8 | | | | |
| 3 | LOSSES | | | 6.5 | 6.5 | | | | |
| 4 | INPUT | | | | 1,657.3 | | | | |
| 5 | **EXPANSION FACTOR** | **1.00395** | | | | | | | |
| 6 | **SECONDARY** | | | | | | | | |
| 7 | SALES | | | | | | | | |
| 8 | LOSSES | | | 1.6 | 1.6 | | | | |
| 9 | INPUT | | | | 1,659.0 | | | | |
| 10 | **EXPANSION FACTOR** | **1.00098** | | | | | | | |
| 11 | **LINE TRANSFORMER** | | | | | | | | |
| 12 | SALES | | | | | | | | |
| 13 | LOSSES | | | 22.5 | 22.5 | | | | |
| 14 | INPUT | | | | 1,681.5 | | | | |
| 15 | **EXPANSION FACTOR** | **1.01357** | | | | | | | |
| 16 | **PRIMARY** | | | | | | | | |
| 17 | SECONDARY | | | | 1,681.5 | | | | |
| 18 | SALES | | 66.10 | | | 66.1 | | | |
| 19 | LOSSES | | | 44.9 | 43.2 | 1.7 | | | |
| 20 | INPUT | | | | | | | | |
| 21 | **EXPANSION FACTOR** | **1.02568** | | | | | | | |
| 22 | **SUBSTATION** | | | | | | | | |
| 23 | PRIMARY | | | | 1,724.7 | 67.8 | | | |
| 24 | SALES | | 13.5 | | | | 13.5 | | |
| 25 | LOSSES | | | 10.4 | 9.9 | 0.4 | 0.1 | | |
| 26 | INPUT | | | | 1,734.6 | 68.2 | 13.6 | | |
| 27 | **EXPANSION FACTOR** | **1.00575** | | | | | | | |
| 28 | **SUB-TRANSMISSION** | | | | | | | | |
| 29 | DISTRIBUTION SUBS | | | | 312.5 | 31.4 | | | |
| 30 | SALES | | 0.00 | | | | 0.0 | 0.0 | |
| 31 | LOSSES | | | 7.4 | 6.7 | 0.7 | 0.0 | 0.00 | |
| 32 | INPUT | | | | 319.2 | 32.0 | 0.0 | 0.00 | |
| 33 | **EXPANSION FACTOR** | **1.02142** | | | | | | | |
| 34 | **TRANSMISSION** | | | | | | | | |
| 35 | SUBTRANSMISSION | | | | 319.2 | 32.0 | | 0.0 | |
| 36 | DISTRIBUTION SUBS | | | | 1,247.4 | 36.8 | 13.6 | | |
| 37 | SALES | | 176.10 | | | | | | 176.1 |
| 38 | LOSSES | | | 51.1 | 40.1 | 1.8 | 0.3 | 0.0 | 4.5 |
| 39 | INPUT | | | | 1,643.5 | 70.6 | 13.9 | 0.0 | 180.6 |
| 40 | **EXPANSION FACTOR** | **1.02557** | | | | | | | |
| 41 | **TOTALS** LOSSES | CALCULATED | | 144.5 | 130.5 | 4.5 | 0.4 | 0.0 | 4.5 |
| | | EXHIBIT 7 | | 144.5 | 135.5 | 4.0 | 0.4 | 0.0 | 4.5 |
| 42 | % OF TOTAL | | | 100% | 93.78% | 2.80% | 0.29% | 0.00% | 3.12% |
| 43 | SALES | | 1,906.5 | | 1,650.8 | 66.1 | 13.5 | 0.0 | 176.1 |
| 44 | % OF TOTAL | | 100.00% | | 86.59% | 3.47% | 0.71% | 0.00% | 9.24% |
| 45 | INPUT | | 2,051.0 | | 1,786.3 | 70.1 | 13.9 | 0.0 | 180.6 |
| 46 | **CUMMULATIVE EXPANSION LOSS FACTORS** (from meter to system input) | | | | **1.08208** | **1.06117** | **NA** | **1.02941** | **1.02557** |

**ENERGY MWH** **SUMMARY OF LOSSES AND LOSS FACTORS BY DELIVERY VOLTAGE** **EXHIBIT 9**
PAGE 2 of 2

| | SERVICE LEVEL | | SALES | LOSSES | SECONDARY | PRIMARY | SUBSTATION | SUBTRANS | TRANSMISSION |
|---|---|---|---|---|---|---|---|---|---|
| 1 | **SERVICES** | | | | | | | | |
| 2 | SALES | | 6,599,276 | | 6,599,276 | | | | |
| 3 | LOSSES | | | 18,687 | 18,687 | | | | |
| 4 | INPUT | | | | 6,617,963 | | | | |
| 5 | **EXPANSION FACTOR** | **1.00283** | | | | | | | |
| 6 | **SECONDARY** | | | | | | | | |
| 7 | SALES | | | | | | | | |
| 8 | LOSSES | | | 2,837 | 2,837 | | | | |
| 9 | INPUT | | | | 6,620,800 | | | | |
| 10 | **EXPANSION FACTOR** | **1.00043** | | | | | | | |
| 11 | **LINE TRANSFORMER** | | | | | | | | |
| 12 | SALES | | | | | | | | |
| 13 | LOSSES | | | 140,424 | 140,424 | | | | |
| 14 | INPUT | | | | 6,761,224 | | | | |
| 15 | **EXPANSION FACTOR** | **1.02121** | | | | | | | |
| 16 | **PRIMARY** | | | | | | | | |
| 17 | SECONDARY | | | | 6,761,224 | | | | |
| 18 | SALES | | 461,821.000 | | | 461,821 | | | |
| 19 | LOSSES | | | 86,859 | 81,306 | 5,554 | | | |
| 20 | INPUT | | | | | | | | |
| 21 | **EXPANSION FACTOR** | **1.01203** | | | | | | | |
| 22 | **SUBSTATION** | | | | | | | | |
| 23 | PRIMARY | | | | 6,842,530 | 467,375 | | | |
| 24 | SALES | | 66,137 | | | | 66,137 | | |
| 25 | LOSSES | | | 49,142 | 45,588 | 3,114 | 441 | | |
| 26 | INPUT | | | | 6,888,117 | 470,488 | 66,578 | | |
| 27 | **EXPANSION FACTOR** | **1.00666** | | | | | | | |
| 28 | **SUB-TRANSMISSION** | | | | | | | | |
| 29 | DISTRIBUTION SUBS | | | | 1,402,440 | 207,015 | 0.000 | | |
| 30 | SALES | | 0 | | | | 0.000 | 0 | |
| 31 | LOSSES | | | 23,314 | 19,887 | 2,935 | 0.000 | 0 | |
| 32 | INPUT | | | | 1,422,327 | 209,950 | | 0 | |
| 33 | **EXPANSION FACTOR** | **1.01418** | | | | | | | |
| 34 | **TRANSMISSION** | | | | | | | | |
| 35 | SUBTRANSMISSION | | | | 1,422,327 | 209,950 | | 0 | |
| 36 | DISTRIBUTION SUBS | | | | 5,500,221 | 263,473 | 66,578 | | |
| 37 | SALES | | 1,162,097 | | | | | | 1,162,097 |
| 38 | LOSSES | | | 220,862 | 177,563 | 12,143 | 1,708 | 0 | 29,808 |
| 39 | INPUT | | | | 7,100,111 | 485,567 | 68,285 | 0 | 1,191,905 |
| 40 | **EXPANSION FACTOR** | **1.02565** | | | | | | | |
| 41 | **TOTALS** LOSSES | Calculated | | 542,125 | 486,291 | 23,746 | 2,148 | 0 | 29,808 |
| | | EXHIBIT 7 | | 542,058 | 488,536 | 21,566 | 2,148 | 0 | 29,808 |
| 42 | % OF TOTAL | | | 100% | 89.70% | 4.38% | 0.40% | | 5.50% |
| 43 | SALES | | 8,289,331 | | 6,599,276 | 461,821 | 66,137 | 0 | 1,162,097 |
| 44 | % OF TOTAL | | 100.00% | | 79.61% | 5.57% | 0.80% | 0.00% | 14.02% |
| 45 | INPUT | | 8,831,389 | | 7,087,812 | 483,387 | 68,285 | 0 | 1,191,905 |
| 46 | **CUMMULATIVE EXPANSION LOSS FACTORS** (from meter to system input) | | | | **1.07403** | **1.04670** | **NA** | **1.02850** | **1.02565** |

# Appendix C

# Discussion of Hoebel Coefficient

**El Paso Electric Company**
**2021 Analysis of System Losses**

## COMMENTS ON HOEBEL COEFFICIENTS

The Hoebel constant represents an established industry standard relationship between peak losses and average losses and is used in a loss study to estimate energy losses from peak demand losses. H. F. Hoebel described this relationship in his article, "Cost of Electric Distribution Losses," Electric Light and Power, March 15, 1959.

Within any loss evaluation study, peak demand losses can readily be calculated given equipment resistance and approximate loading. Energy losses, however, are much more difficult to determine given their time-varying nature. This difficulty can be reduced by the use of an equation which relates peak load losses (demand) to average losses (energy). Once the relationship between peak and average losses is known, average losses can be estimated from the known peak load losses.

Within the electric utility industry, the relationship between peak and average losses is known as the loss factor. For definitional purposes, loss factor is the ratio of the average power loss to the peak load power loss, during a specified period of time. This relationship is expressed mathematically as follows:

$$(1)\ F_{LS} \cong A_{LS} \div P_{LS}$$

where: $F_{LS}$ = Loss Factor
$A_{LS}$ = Average Losses
$P_{LS}$ = Peak Losses

The loss factor provides an estimate of the degree to which the load loss is maintained throughout the period in which the loss is being considered. In other words, loss factor is the ratio of the actual kWh losses incurred to the kWh losses which would have occurred if full load had continued throughout the period under study.

Examining the loss factor expression in light of a similar expression for load factor indicates a high degree of similarity. The mathematical expression for load factor is as follows:

$$(2)\ F_{LD} \cong A_{LD} \div P_{LD}$$

where: $F_{LD}$ = Load Factor
$A_{LD}$ = Average Load
$P_{LD}$ = Peak Load

This load factor result provides an estimate of the degree to which the load loss is maintained throughout the period in which the load is being considered. Because of the similarities in definition, the loss factor is sometimes called the "load factor of losses." While the definitions are similar, a strict equating of the two factors cannot be made. There does exist, however, a relationship between these two factors which is dependent upon the shape of the load duration curve. Since resistive losses vary as the square of the load, it can be shown mathematically that the loss factor can vary between the extreme limits of load factor and load factor squared. The

**El Paso Electric Company**
**2021 Analysis of System Losses**

relationship between load factor and loss factor has become an industry standard and is as follows:

(3) $F_{LS} \cong H*F_{LD}^2 + (1-H)*F_{LD}$

where:

| | | |
|---|---|---|
| $F_{LS}$ | = | Loss Factor |
| $F_{LD}$ | = | Load Factor |
| H | = | Hoebel Coefficient |

As noted in the attached article, the suggested value for H (the Hoebel coefficient) is 0.7. The exact value of H will vary as a function of the shape of the utility's load duration curve. In recent years, values of H have been computed directly for a number of utilities based on EEI load data. It appears on this basis, the suggested value of 0.7 should be considered a lower bound and that values approaching unity may be considered a reasonable upper bound. Based on experience, values of H have ranged from approximately 0.85 to 0.95. The standard default value of 0.9 is generally used.

Inserting the Hoebel coefficient estimate gives the following loss factor relationship using Equation (3):

(4) $F_{LS} \cong 0.90*F_{LD}^2 + 0.10*F_{LD}$

Once the Hoebel constant has been estimated and the load factor and peak losses associated with a piece of equipment have been estimated, one can calculate the average, or energy losses as follows:

(5) $A_{LS} \cong P_{LS} * [H*F_{LD}^2 + (1-H)*F_{LD}]$

where:

| | | |
|---|---|---|
| $A_{LS}$ | = | Average Losses |
| $P_{LS}$ | = | Peak Losses |
| H | = | Hoebel Coefficient |
| $F_{LD}$ | = | Load Factor |

Loss studies use this equation to calculate energy losses at each major voltage level in the analysis.

**Exhibit ES-5 Historical Weather in Las Cruces, NM and El Paso, TX**



| Las Cruces | | | El Paso | | | Percent Difference LC vs. EP | | |
|---|---|---|---|---|---|---|---|---|
| Year | HDD | CDD | Year | HDD | CDD | Year | HDD | CDD |
| 2009 | 2,882 | 1,898 | 2009 | 2,224 | 2,775 | 2009 | 30% | -32% |
| 2010 | 3,090 | 1,859 | 2010 | 2,354 | 2,739 | 2010 | 31% | -32% |
| 2011 | 3,108 | 2,109 | 2011 | 2,473 | 3,143 | 2011 | 26% | -33% |
| 2012 | 2,664 | 2,005 | 2012 | 2,088 | 2,878 | 2012 | 28% | -30% |
| 2013 | 3,209 | 1,976 | 2013 | 2,501 | 2,697 | 2013 | 28% | -27% |
| 2014 | 2,663 | 1,960 | 2014 | 1,979 | 2,671 | 2014 | 35% | -27% |
| 2015 | 2,911 | 1,949 | 2015 | 2,185 | 2,838 | 2015 | 33% | -31% |
| 2016 | 2,659 | 2,015 | 2016 | 1,920 | 2,812 | 2016 | 38% | -28% |
| 2017 | 2,259 | 2,005 | 2017 | 1,589 | 2,925 | 2017 | 42% | -31% |
| 2018 | 2,640 | 2,335 | 2018 | 2,017 | 3,176 | 2018 | 31% | -26% |
| 2019 | 2,722 | 2,105 | 2019 | 2,208 | 3,010 | 2019 | 23% | -30% |
| 2020 | 2,676 | 2,383 | 2020 | 2,073 | 3,311 | 2020 | 29% | -28% |
| 2021 | 2,377 | 2,057 | 2021 | 1,950 | 2,693 | 2021 | 22% | -24% |
| 2022 | 2,934 | 2,279 | 2022 | 2,396 | 2,937 | 2022 | 22% | -22% |
| 2023 | 2,476 | 2,614 | 2023 | 1,985 | 3,537 | 2023 | 25% | -26% |
| Average (2009-2023) | 2,751 | 2,103 | Average (2009-2023) | 2,129 | 2,943 | Average (2009-2023) | 30% | -29% |

Exhibit ES-5
Page 1 of 1

| | Oct-23 | Nov-23 | Dec-23 | Jan-24 | Feb-24 | Mar-24 | Apr-24 | May-24 | Jun-24 | Jul-24 | Aug-24 | Sep-24 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Actual Weather** | | | | | | | | | | | | |
| ***El Paso*** | | | | | | | | | | | | |
| HDD-2MA | 24 | 145 | 361 | 493 | 421 | 251 | 117 | 34 | 0 | 0 | 0 | 0 |
| CDD-2MA | 394 | 134 | 16 | 0 | 4 | 12 | 75 | 296 | 595 | 709 | 704 | 595 |
| ***Las Cruces*** | | | | | | | | | | | | |
| HDD-2MA | 41 | 227 | 494 | 618 | 506 | 308 | 161 | 49 | 0 | 0 | 0 | 0 |
| CDD-2MA | 241 | 47 | 2 | 0 | 0 | 2 | 31 | 160 | 439 | 611 | 604 | 476 |
| **10-Year Avg Weather*** | | | | | | | | | | | | |
| ***El Paso*** | | | | | | | | | | | | |
| HDD-2MA | 29 | 173 | 414 | 558 | 470 | 273 | 114 | 25 | 3 | 0 | 0 | 1 |
| CDD-2MA | 269 | 76 | 4 | 0 | 1 | 14 | 82 | 245 | 486 | 646 | 634 | 506 |
| ***Las Cruces*** | | | | | | | | | | | | |
| HDD-2MA | 59 | 258 | 515 | 643 | 554 | 366 | 193 | 61 | 10 | 0 | 0 | 2 |
| CDD-2MA | 172 | 30 | 0 | 0 | 0 | 3 | 32 | 131 | 349 | 531 | 523 | 388 |
| **Coefficients** | **Oct-23** | **Nov-23** | **Dec-23** | **Jan-24** | **Feb-24** | **Mar-24** | **Apr-24** | **May-24** | **Jun-24** | **Jul-24** | **Aug-24** | **Sep-24** |
| TXRT01- Residential | 0.8239 | 0.2286 | 0.2272 | 0.3449 | 0.1985 | 0.1287 | 0.2705 | 0.4603 | 0.7116 | 0.8700 | 0.8632 | 0.9387 |
| TXRT02- Small Commercial | 15,719.7500 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 9,724.1570 | 14,654.7600 | 18,242.0900 | 17,645.6200 | 19,751.8600 |
| TXRT22- Irrigation | 309.7031 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 297.8907 | 394.9944 | 321.1153 | 261.4677 | 257.7921 |
| TXRT24- General Service | 87,786.0600 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 52,291.5000 | 69,168.8600 | 85,286.0100 | 74,406.3200 | 92,080.5500 |
| TXRT31- Military | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 8,529.8240 | 6,362.3610 | 6,264.9050 | 5,672.7950 |
| TXRT41- City & County | 15,042.1700 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 10,860.4300 | 7,832.1760 | 4,839.0200 | 12,272.7800 | 19,966.3200 |
| NMRT01- Residential | 0.9287 | 0.1365 | 0.2772 | 0.4239 | 0.2860 | 0.1898 | 0.1629 | 0.5569 | 0.8161 | 0.9382 | 0.9197 | 1.0504 |
| NMRT03- Small Commercial | 14,413.2600 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 6,254.5170 | 10,224.9000 | 12,005.8800 | 11,785.2300 | 14,140.5500 |
| NMRT04- General Service | 19,474.0900 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 10,265.3500 | 13,274.2600 | 14,970.7400 | 15,276.4100 | 19,267.9100 |
| NMRT05- Irrigation | 4,664.3460 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 7,663.9050 | 4,287.3880 | 2,417.2480 | 2,281.5010 | 3,422.0390 |
| NMRT07- City & County | 6,300.9530 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 2,777.3600 | 2,118.6670 | 2,091.2790 | 3,408.5440 | 6,648.5360 |
| NMRT08- Pumping | 2,301.8350 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 3,374.3890 | 2,179.7930 | 2,105.5170 | 1,704.3680 | 2,264.8960 |
| NMRT10-Military | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 7,941.3610 | 7,021.8070 | 7,917.5710 | 7,544.9290 |
| NMRT26-State University | 4,183.3430 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 3,009.3980 | 2,763.8600 | 2,478.0630 | 2,711.0160 | 4,183.2550 |
| **Number of Customers for UPC Models** | **Oct-23** | **Nov-23** | **Dec-23** | **Jan-24** | **Feb-24** | **Mar-24** | **Apr-24** | **May-24** | **Jun-24** | **Jul-24** | **Aug-24** | **Sep-24** |
| TXRT01- Residential | 313,189 | 312,036 | 309,687 | 310,127 | 307,975 | 308,843 | 306,471 | 308,903 | 313,139 | 314,340 | 316,232 | 316,673 |
| NMRT01- Residential | 94,608 | 94,643 | 93,904 | 93,467 | 92,483 | 92,327 | 92,718 | 93,628 | 94,312 | 95,188 | 95,687 | 95,853 |

***Note:** 10-year weather averages for October 2023-December 2023 are for the ten year period of 2013-2022; 10-year weather averages for January 2024 - September 2024 are for the ten year period of 2014-2023

| Description | Oct-23 | Nov-23 | Dec-23 | Jan-24 | Feb-24 | Mar-24 | Apr-24 | May-24 | Jun-24 | Jul-24 | Aug-24 | Sep-24 | Test Year Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Weather Adjustments to kWh | | | | | | | | | | | | | |
| TXRT01- Residential | (32,255,766) | 1,997,498 | 3,729,308 | 6,952,582 | 2,995,428 | 874,546 | (248,731) | (7,251,701) | (24,289,258) | (17,228,401) | (19,108,113) | (26,455,914) | (110,288,520) |
| TXRT02- Small Commercial | (1,964,969) | 0 | 0 | 0 | 0 | 0 | 0 | (495,932) | (1,597,369) | (1,149,252) | (1,235,193) | (1,757,916) | (8,200,630) |
| TXRT22- Irrigation | (38,713) | 0 | 0 | 0 | 0 | 0 | 0 | (15,192) | (43,054) | (20,230) | (18,303) | (22,943) | (158,436) |
| TXRT24- General Service | (10,973,258) | 0 | 0 | 0 | 0 | 0 | 0 | (2,666,867) | (7,539,406) | (5,373,019) | (5,208,442) | (8,195,169) | (39,956,160) |
| TXRT31- Military | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | (929,751) | (400,829) | (438,543) | (504,879) | (2,274,002) |
| TXRT41- City & County | (1,880,271) | 0 | 0 | 0 | 0 | 0 | 0 | (553,882) | (853,707) | (304,858) | (859,095) | (1,777,002) | (6,228,816) |
| Total Weather Adjustment | (47,112,976) | 1,997,498 | 3,729,308 | 6,952,582 | 2,995,428 | 874,546 | (248,731) | (10,983,574) | (35,252,545) | (24,476,589) | (26,867,690) | (38,713,823) | (167,106,564) |

| | CDD | HDD | HDD | HDD | HDD | HDD | HDD | CDD | CDD | CDD | CDD | CDD | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Description** | **Oct-23** | **Nov-23** | **Dec-23** | **Jan-24** | **Feb-24** | **Mar-24** | **Apr-24** | **May-24** | **Jun-24** | **Jul-24** | **Aug-24** | **Sep-24** | **Test Year Total** |
| Weather Adjustments to kWh | | | | | | | | | | | | | |
| NMRT01- Residential | (6,062,751) | 400,494 | 546,721 | 990,512 | 1,269,616 | 1,016,565 | 483,344 | (1,512,148) | (6,927,122) | (7,144,453) | (7,128,495) | (8,860,082) | (32,927,799) |
| NMRT03- Small General | (994,515) | 0 | 0 | 0 | 0 | 0 | 0 | (181,381) | (920,241) | (960,470) | (954,604) | (1,244,368) | (5,255,579) |
| NMRT04- General Service | (1,343,712) | 0 | 0 | 0 | 0 | 0 | 0 | (297,695) | (1,194,683) | (1,197,659) | (1,237,389) | (1,695,576) | (6,966,715) |
| NMRT05- Irrigation | (321,840) | 0 | 0 | 0 | 0 | 0 | 0 | (222,253) | (385,865) | (193,380) | (184,802) | (301,139) | (1,609,279) |
| NMRT07- City & County | (434,766) | 0 | 0 | 0 | 0 | 0 | 0 | (80,543) | (190,680) | (167,302) | (276,092) | (585,071) | (1,734,455) |
| NMRT08- Pumping | (158,827) | 0 | 0 | 0 | 0 | 0 | 0 | (97,857) | (196,181) | (168,441) | (138,054) | (199,311) | (958,671) |
| NMRT10- Military | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | (714,722) | (561,745) | (641,323) | (663,954) | (2,581,744) |
| NMRT26- State University | (288,651) | 0 | 0 | 0 | 0 | 0 | 0 | (87,273) | (248,747) | (198,245) | (219,592) | (368,126) | (1,410,634) |
| Total Weather Adjustment | (9,605,061) | 400,494 | 546,721 | 990,512 | 1,269,616 | 1,016,565 | 483,344 | (2,479,150) | (10,778,243) | (10,591,696) | (10,780,351) | (13,917,628) | (53,444,877) |
| | | | | | | | | | | | | Total EPE Weather Impact | (220,551,441) |

**APPENDIX A**
EL PASO ELECTRIC COMPANY
2024-2033 DEMAND AND ENERGY FORECAST

***Summary***

| **ENERGY (GWH)** | **2023 (1)** | **2024** | **2025** | **2026** | **2027** | **2028** | **2029** | **2030** | **2031** | **2032** | **2033** | **10-YR (6) CAGR** |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Native System Forecast (NFL) (2) | | | | | | | | | | | | |
| Upper Bound | | 9,750 | 10,011 | 10,190 | 10,349 | 10,497 | 10,645 | 10,802 | 10,960 | 11,121 | 11,287 | |
| **Expected:** | 9,138 | 9,508 | 9,749 | 9,906 | 10,044 | 10,175 | 10,306 | 10,449 | 10,594 | 10,742 | 10,895 | **1.8** |
| Lower Bound | | 9,266 | 9,487 | 9,622 | 9,740 | 9,853 | 9,968 | 10,097 | 10,228 | 10,363 | 10,504 | |
| Less: DG (3) | | 50 | 100 | 150 | 199 | 249 | 298 | 346 | 395 | 443 | 491 | |
| Less: EE (4) | | 37 | 74 | 111 | 148 | 185 | 222 | 260 | 297 | 334 | 371 | |
| Plus: EV (5) | | 12 | 27 | 49 | 80 | 123 | 182 | 263 | 371 | 511 | 683 | |
| **Native System Energy** | | | | | | | | | | | | |
| Upper Bound | | 9,674 | 9,860 | 9,969 | 10,065 | 10,164 | 10,279 | 10,426 | 10,602 | 10,813 | 11,066 | |
| **Expected:** | **9,138** | **9,432** | **9,602** | **9,694** | **9,776** | **9,864** | **9,969** | **10,107** | **10,274** | **10,475** | **10,717** | **1.6** |
| Lower Bound | | 9,190 | 9,343 | 9,418 | 9,488 | 9,563 | 9,659 | 9,788 | 9,946 | 10,138 | 10,368 | |
| | | | | | | | | | | | | |
| **DEMAND (MW)** | | | | | | | | | | | | |
| Native System Forecast (NFL) | | | | | | | | | | | | |
| Upper Bound | | 2,484 | 2,579 | 2,649 | 2,716 | 2,774 | 2,847 | 2,890 | 2,931 | 2,966 | 3,016 | |
| **Expected:** | 2,384 | 2,353 | 2,443 | 2,507 | 2,568 | 2,621 | 2,689 | 2,726 | 2,764 | 2,795 | 2,843 | **1.8** |
| Lower Bound | | 2,223 | 2,308 | 2,365 | 2,420 | 2,467 | 2,530 | 2,563 | 2,596 | 2,624 | 2,669 | |
| Less: DG | | 7 | 19 | 31 | 44 | 56 | 68 | 79 | 91 | 103 | 115 | |
| Less: EE | | 10 | 20 | 29 | 39 | 49 | 59 | 69 | 79 | 89 | 99 | |
| Plus: EV | | 2 | 4 | 7 | 11 | 16 | 23 | 33 | 46 | 62 | 81 | |
| **Native System Demand:** | | | | | | | | | | | | |
| Upper Bound | | 2,469 | 2,544 | 2,593 | 2,640 | 2,680 | 2,737 | 2,766 | 2,797 | 2,824 | 2,871 | |
| **Expected:** | **2,384** | **2,338** | **2,408** | **2,453** | **2,496** | **2,532** | **2,586** | **2,611** | **2,640** | **2,665** | **2,711** | **1.3** |
| Lower Bound | | 2,208 | 2,273 | 2,313 | 2,351 | 2,383 | 2,434 | 2,456 | 2,482 | 2,506 | 2,550 | |
| Interruptible Load | | 32 | 32 | 32 | 32 | 32 | 32 | 32 | 32 | 32 | 32 | |
| Upper Bound | | 2,432 | 2,505 | 2,554 | 2,600 | 2,639 | 2,696 | 2,724 | 2,755 | 2,782 | 2,829 | |
| **Expected:** | **2,384** | **2,306** | **2,377** | **2,421** | **2,464** | **2,500** | **2,554** | **2,579** | **2,608** | **2,633** | **2,679** | **1.2** |
| Lower Bound | | 2,171 | 2,237 | 2,278 | 2,317 | 2,350 | 2,401 | 2,424 | 2,450 | 2,474 | 2,518 | |

Footnotes:
(1) 2023 are Actual data, Native System Peak occurred on July 19th.
(2) Net Load is forecasted load before the removal of DG and EE.
(3) Impact from Distributed Generation.
(4) Impact from Energy Efficiency.
(5) Impact from Electric Vehicles.
(6) 10-Year Compounded Average Growth Rate.

Exhibit ES-7
Page 1 of 2

# APPENDIX A
EL PASO ELECTRIC COMPANY
2034-2043 DEMAND AND ENERGY FORECAST

***Summary***

| ENERGY (GWH) | 2034 | 2035 | 2036 | 2037 | 2038 | 2039 | 2040 | 2041 | 2042 | 2043 | 20-YR (1) CAGR |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Native System Forecast (NFL) | | | | | | | | | | | |
| Upper Bound | 11,459 | 11,637 | 11,814 | 11,996 | 12,186 | 12,380 | 12,588 | 12,799 | 13,019 | 13,248 | |
| **Expected:** | 11,056 | 11,222 | 11,388 | 11,559 | 11,736 | 11,919 | 12,115 | 12,315 | 12,522 | 12,740 | **1.7** |
| Lower Bound | 10,653 | 10,807 | 10,962 | 11,121 | 11,287 | 11,459 | 11,643 | 11,831 | 12,026 | 12,231 | |
| Less: DG (3) | 539 | 586 | 633 | 680 | 727 | 773 | 820 | 866 | 911 | 957 | |
| Less: EE (4) | 408 | 445 | 482 | 519 | 556 | 593 | 630 | 667 | 704 | 742 | |
| Plus: EV (5) | 888 | 1,118 | 1,360 | 1,599 | 1,823 | 2,020 | 2,186 | 2,320 | 2,425 | 2,505 | |
| **Native System Energy:** | | | | | | | | | | | |
| Upper Bound | 11,361 | 11,687 | 12,030 | 12,378 | 12,718 | 13,039 | 13,342 | 13,618 | 13,871 | 14,109 | |
| **Expected:** | **10,998** | **11,308** | **11,632** | **11,958** | **12,276** | **12,573** | **12,851** | **13,102** | **13,332** | **13,547** | **2** |
| Lower Bound | 10,635 | 10,929 | 11,234 | 11,539 | 11,834 | 12,106 | 12,360 | 12,586 | 12,792 | 12,985 | |
| | | | | | | | | | | | |
| **DEMAND (MW)** | | | | | | | | | | | |
| Native System Forecast | | | | | | | | | | | |
| Upper Bound | 3,061 | 3,107 | 3,144 | 3,199 | 3,247 | 3,297 | 3,341 | 3,404 | 3,460 | 3,518 | |
| **Expected:** | 2,884 | 2,928 | 2,963 | 3,016 | 3,062 | 3,110 | 3,152 | 3,213 | 3,267 | 3,324 | **1.7** |
| Lower Bound | 2,708 | 2,749 | 2,782 | 2,832 | 2,877 | 2,923 | 2,963 | 3,022 | 3,074 | 3,129 | |
| Less: DG | 126 | 138 | 149 | 161 | 172 | 184 | 195 | 206 | 217 | 228 | |
| Less: EE | 108 | 118 | 128 | 138 | 148 | 158 | 168 | 177 | 187 | 197 | |
| Plus: EV | 104 | 128 | 153 | 177 | 198 | 215 | 229 | 239 | 245 | 249 | |
| **Native System Demand:** | | | | | | | | | | | |
| Upper Bound | 2,916 | 2,963 | 3,004 | 3,060 | 3,108 | 3,154 | 3,191 | 3,242 | 3,283 | 3,324 | |
| **Expected:** | **2,753** | **2,800** | **2,838** | **2,893** | **2,940** | **2,984** | **3,019** | **3,068** | **3,108** | **3,147** | **1.4** |
| Lower Bound | 2,591 | 2,636 | 2,673 | 2,727 | 2,771 | 2,814 | 2,847 | 2,895 | 2,933 | 2,971 | |
| Interruptible Load: | 32 | 32 | 32 | 32 | 32 | 32 | 32 | 32 | 32 | 32 | |
| Upper Bound | 2,873 | 2,921 | 2,961 | 3,018 | 3,066 | 3,111 | 3,148 | 3,199 | 3,240 | 3,282 | |
| **Expected:** | **2,722** | **2,768** | **2,807** | **2,862** | **2,908** | **2,952** | **2,987** | **3,036** | **3,076** | **3,116** | **1.3** |
| Lower Bound | 2,560 | 2,604 | 2,642 | 2,695 | 2,740 | 2,782 | 2,815 | 2,863 | 2,901 | 2,939 | |

Footnotes:
(1) 20-Year Compounded Average Growth Rate.

Exhibit ES-7
Page 2 of 2

DOCKET NO. 57568

| | | |
|---|---|---|
| APPLICATION OF EL PASO<br>ELECTRIC COMPANY TO CHANGE<br>RATES | §<br>§<br>§ | PUBLIC UTILITY COMMISSION<br>OF TEXAS |

DIRECT TESTIMONY

OF

ADRIAN HERNANDEZ

FOR

EL PASO ELECTRIC COMPANY

JANUARY 2025

## EXECUTIVE SUMMARY

Adrian Hernandez is a Supervisor of Revenue Requirements and Cost Analysis in El Paso Electric Company's ("EPE" or "Company") Regulatory Division. In his testimony, Mr. Hernandez describes the cost-of-service model that EPE employs to produce the Texas jurisdictional cost-of-service study, class cost-of-service study, demand, energy, and customer components study, and the functional cost-of-service study. The cost of service supports EPE's revenue requirement, rate design proposals, and the development of new baselines for the Distribution Cost Recovery Factor ("DCRF"), the Transmission Cost Recovery Factor ("TCRF"), the Generation Cost Recovery Rider ("GCRR"), and the Purchased Power Capacity Cost Recovery Factor ("PCRF"). Mr. Hernandez will also provide testimony to support the revenue requirement for the Retiring Plant Rider Factor ("RPRF") and he will propose a modification to EPE's AMS Surcharge to reduce the estimated savings in the surcharge for those savings already reflected in the test year.

## TABLE OF CONTENTS

**SUBJECT** **PAGE**



## EXHIBITS

## I. Introduction and Qualifications

Q1. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Adrian Hernandez. My business address is 100 N. Stanton Street, El Paso, Texas 79901.

Q2. HOW ARE YOU EMPLOYED?

A. I am employed by El Paso Electric Company ("EPE" or the "Company") as a Supervisor - Revenue Requirements and Cost Analysis.

Q3. PLEASE SUMMARIZE YOUR EDUCATIONAL AND PROFESSIONAL QUALIFICATIONS.

A. In May 2007, I graduated from the University of Texas at Austin with a Bachelor of Business Administration in Accounting and a minor in Finance. In August 2011, I earned a Master of Accountancy degree from the University of Texas at El Paso. In 2014, I received a graduate certificate from New Mexico State University ("NMSU") in Public Utility Regulation & Economics. I pursued further studies at NMSU, completing the Master of Business Administration program in December 2017. Finally, I hold a Certified Public Accountant license issued by the State of Texas which mandates ongoing training hours for license renewal.

After earning my bachelor's degree, I was employed by BearingPoint Inc., in the Washington, D.C., metro area, where I worked as a business analyst in that company's public services division. In June 2008, I moved to El Paso, Texas, and was employed as a Cost Accountant for Helen of Troy Limited. Thereafter, in August 2009, I accepted a job as a regulatory accountant with EPE. My duties as a regulatory accountant consisted of preparing and reviewing jurisdictional regulatory accounting, fuel and operational reports, schedules, and supporting work papers. I worked extensively on fuel related matters, such as accounting for fuel expenses, monitoring the over/under collection of fuel, and preparing any fuel related regulatory filings.

In 2014, I joined the Rates and Regulatory Affairs Department where my responsibilities were to perform or assist in the preparation of economic, statistical, and cost studies. I was later promoted to Senior Rate Analyst in 2016 where I continued to develop models and methodologies for cost of service, profitability, and pricing studies; and to perform annualization and cost of service studies, rate design, and revenue forecasts. I also participated in regulatory filings like base rate cases, fuel rate revisions, energy efficiency and advanced metering.

In June 2022 I was promoted to Principal Rate Analyst where, in addition to those already mentioned in the paragraph above, my responsibilities as Principal Rate Analyst included implementing a new regulatory solution from Utilities International Solutions Group ("UISG") or ("UI"). This regulatory solution is what I used to prepare EPE's cost-of-service model. In December 2024, I was promoted to the Supervisor of the Revenue Requirements and Cost Analysis department.

Q4. PLEASE DESCRIBE YOUR CURRENT RESPONSIBILITIES WITH EPE.

A. My responsibilities as the Supervisor of the newly created Revenue Requirements and Cost Analysis department are to lead a team responsible for producing accurate and comprehensive cost of service and revenue requirements for various regulatory filings and internal company analyses. This includes managing the creation of schedules, workpapers, and exhibits using the UI Regulatory solution, and ensuring compliance with regulatory standards and procedures.

Q5. HAVE YOU PREVIOUSLY PRESENTED TESTIMONY BEFORE UTILITY REGULATORY BODIES?

A. Yes, I have testified on behalf of EPE in cases before the Public Utility Commission of Texas ("Commission" or "PUCT") and the New Mexico Public Regulation Commission.

## II. Purpose of Testimony

Q6. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to present EPE's cost-of-service ("COS") studies. EPE's cost-of-service studies consist of the functional cost-of-service ("FCOS") study; jurisdictional cost-of-service ("JCOS") study; demand, energy, and customer ("DEC") component costs ("DEC Study"); and class cost-of-service ("CCOS") study. Those studies are used to develop EPE's proposed rates as explained in the direct testimony of EPE witness Manuel Carrasco.

I will also present testimony to reset the baselines for EPE's Distribution Cost Recovery Factor ("DCRF"), Transmission Cost Recovery Factor ("TCRF"), and the Generation Cost Recovery Rider ("GCRR"). For the first time, EPE will also establish a baseline for Purchased Power Capacity Cost Recovery Factor ("PCRF").

My testimony also presents the calculation of the revenue requirement used to calculate the Retiring Plant Rider.

Finally, my testimony will also explain EPE's proposal to modify the Texas AMS Surcharge to reduce the O&M savings included in the tariff since those savings are already reflected in EPE's test year.

Q7. WHAT SCHEDULES DO YOU SPONSOR OR CO-SPONSOR?

A. Exhibit AH-1 lists the schedules I sponsor or co-sponsor.

Q8. ARE YOU SPONSORING ANY EXHIBITS IN YOUR TESTIMONY?

A. Yes. I am sponsoring the exhibits listed in the Table of Contents page and which are attached to this testimony.

Q9. WERE THE SCHEDULES AND EXHIBITS YOU ARE SPONSORING OR CO-SPONSORING PREPARED BY YOU OR UNDER YOUR DIRECT SUPERVISION?

A. Yes, they were.

## III. Cost-of-Service Study Overview

Q10. IS A COST-OF-SERVICE STUDY REQUIRED AS PART OF A GENERAL RATE CASE FILING?

A. Yes. The Commission's Electric Utility Rate Filing Package for Generating Utilities ("RFP") requires utilities with non-Texas jurisdictional sales to file a schedule summarizing the utility's overall cost of service on a Texas retail basis by use of a jurisdictional allocation study in support of Schedules A and B. The fully allocated

CCOS study is included in the P Schedules of the RFP. The purpose of a cost-of-service study is to appropriately allocate costs to customer groups using cost causation principles to ensure fair pricing of electric service. The results of the COS studies are used by EPE witness Carrasco.

Q11. WHAT DATA ARE USED IN EPE'S COST-OF-SERVICE STUDIES?

A. The cost-of-service studies use data based on EPE's Test Year ended September 30, 2024. The historical Test Year data were compiled from EPE's accounting records, which are maintained in accordance with the Federal Energy Regulatory Commission ("FERC") Uniform System of Accounts, as prescribed by the Commission.

As discussed in the direct testimony of EPE witness Steven Sierra, the historical Test Year was adjusted for known and measurable changes to obtain adjusted total Company amounts.

Q12. WHAT ARE THE TYPICAL STEPS INVOLVED IN DEVELOPING A COST-OF-SERVICE STUDY?

A. The cost-of-service study typically consists of three steps: functionalization, classification, and assignment. Each of these steps is described below.

Q13. PLEASE DESCRIBE COST FUNCTIONALIZATION.

A. Once the test year costs are finalized and recorded in EPE's accounting ledgers, the accounting data can be utilized to determine the functions associated with those costs. These functions are:

- Production – costs associated with the production of energy and capacity, including purchased power;
- Transmission – costs associated with the high voltage system that transports the power to load centers;
- Distribution – costs associated with distributing the energy from the transmission system to the end users;
- Customer Service – costs associated with providing service to the customer–e.g., meter reading, billing, etc.; and

- Administrative and General – common costs, such as management, buildings, software, support services, etc., which are incurred to support the core functions of electric service listed above.

EPE's cost of service now includes a Functional COS step. I will discuss this new step in more detail later.

Q14. PLEASE DESCRIBE COST CLASSIFICATION.

A. The next step is to classify the functionalized costs according to the characteristics of the utility service being provided. The three principal cost classifications are demand-related costs, energy-related costs, and customer-related costs.

- Demand-related costs are those fixed costs that are related to the kilowatt ("kW") demand that the customers place on the system at any point in time. These costs vary with the maximum demand imposed on the various components (facilities) of the power system by the customers.
- Energy-related costs are those costs that are related to the kilowatt-hours ("kWh") of energy that the customer utilizes over time. These costs, primarily fuel, vary with the overall quantity of energy consumed.
- Customer-related costs are those costs incurred as a result of the number of customers on the system but irrespective of the customer's load. These costs, such as meters and billing, are incurred to serve individual customers.

EPE's COS model incorporates the classification of costs at a more detailed level in its DEC study.

Q15. ONCE THE COST OF SERVICE IS FUNCTIONALIZED AND CLASSIFIED, HOW ARE COSTS ASSIGNED?

A. After functionalization and classification, responsibility for each cost is then determined through allocation or direct assignment. The process of allocating costs starts with using operating and accounting data to develop allocation factors by rate class that correspond to each cost classification factor (demand, energy, and customer). These allocation factors are then calculated as percentages (i.e., Texas jurisdiction or residential class as a percent of total). The allocation factors are then applied to specific costs and rate-base items to derive EPE's cost of service for each jurisdiction or rate class. If costs were incurred to benefit a clearly identifiable jurisdiction or rate class, a direct assignment of that cost is made.

Q16. HAS EPE MADE ANY CHANGES TO THE COST-OF-SERVICE MODEL SINCE ITS LAST TEXAS BASE-RATE CASE, DOCKET NO. 52195[1]?

A. Yes. EPE has implemented a new regulatory software solution from UISG to prepare its COS studies.

Q17. ARE THERE ANY SIGNIFICANT DIFFERENCES BETWEEN THE UISG COST-OF-SERVICE MODEL COMPARED TO THE PRIOR COS MODEL?

A. Yes. The first major difference is that the UISG regulatory module integrates with EPE's other UISG modules that have also been implemented. Another significant difference is that EPE's new COS model now includes a functional allocation step early in the process which will make the assignment to functions more transparent. Some other significant differences include:

- Improved accounting code block presentation
- Automation of essential schedules and workpapers
- Quicker turn-around time in model runs.

Q18. HAS THE OVERALL METHODOLOGY OF THE COST-OF-SERVICE MODEL CHANGED WITH THE USE OF THE UISG REGULATORY MODEL?

A. No. Even with some of the updates we have made with the new UISG model, the overall methodology has not changed. EPE continues to use the National Association of Regulatory Utility Commissioners' ("NARUC") "Electric Utility Cost Allocation Manual" ("NARUC Manual") as a general guide for its cost of service.

While EPE's overall approach will not change, some new cost allocation modifications will be proposed in this filing. I discuss these modifications in more detail later in my testimony.

[1]Application of El Paso Electric Company to Change Rates, Docket No. 52195, Order (Sept. 15, 2022).

## IV. Functional Cost-of-Service Study

Q19. WHY HAS EPE PRODUCED A FUNCTIONAL COST-OF-SERVICE STUDY?

A. EPE has always functionalized its costs as part of the process of preparing its COS studies, but it has not been as clear and obvious with EPE's previous COS models. Therefore, in the interest of being more transparent and to improve allocations, EPE's COS studies will now include a Functional Cost-of-Service (FCOS) study as its first step before preparing the JCOS.

Q20. HOW DOES EPE DETERMINE THE FUNCTION THAT APPLIES TO THE COSTS?

A. EPE first relies on the FERC Account classification to determine whether the cost is associated with Production, Transmission, Distribution, or Customer. For example, the operation and maintenance ("O&M") expense accounts are presented in the uniform system of accounts in their respective sections by function. Also, EPE's plant in service is reported by functional class and utility plant accounts that make it easy to determine the high-level function with which it is associated.

Q21. WHAT TYPES OF ALLOCATORS ARE USED IN THE FUNCTIONAL COST-OF-SERVICE STUDY?

A. In general, the UISG model utilizes two general types of allocators: "input" (or external allocators), and "dynamic" (or internal allocators). Input allocators typically come from another source and are either imported or manually input into the COS model. In this case, the input allocators are quite simple in the FCOS study since most of the costs are directly assigned (100%) to either Production, Transmission, Distribution, or Customer based on the accounts and other accounting code block detail.

In contrast, a dynamic allocator is derived from accounts that have already been allocated using a combination of allocators; examples include Net Plant and Labor. Using Net Plant as an example, the functionalized costs of plant-in-service costs net of accumulated depreciation are each initially assigned to each function using input allocators costs with known functions. The summed-up results are then used internally to develop a Net Plant dynamic allocator ("NETPLT"). The NETPLT allocator is used to allocate certain costs such as deferred income taxes in the FCOS.

Q22. HOW ARE ALLOCATORS ASSIGNED TO COSTS IN THE FCOS?

A. For the most part, the assignment of functional allocators is fairly straightforward in the FCOS since most Plant and O&M costs are reported by functionalized accounts. For additional detail, EPE relies on other fields in the accounting code block such as Operating Segment, Expenditure Type, and Project from its cost repository as well as more specific fields (such as depreciation groups or schedule M items) from the plant or tax ledgers.

Q23. HOW DOES EPE ASSIGN ALLOCATORS TO COSTS IN THE FCOS WHERE THE FUNCTION IS NOT KNOWN?

A. There are many instances where certain costs have no direct association with a function but are still assigned to a function indirectly. For example, General Plant and most Administrative and General expenses are typically assigned a Labor allocator which is derived from O&M payroll costs included within the production, transmission, distribution and customer service functions. Other dynamic allocators spread costs to functions based on net plant or rate base in the FCOS.

## V. Jurisdictional Cost-of-Service Study

Q24. WHY IS IT NECESSARY FOR EPE TO PRODUCE A JURISDICTIONAL COST-OF-SERVICE STUDY?

A. EPE provides service to customers in west Texas and southern New Mexico. To provide the revenue and cost data for EPE's Texas service area that is required for preparation of several schedules, it is necessary to first produce a jurisdictional cost-of-service (JCOS) study for the Texas retail jurisdiction. The JCOS serves as the foundation for the class cost-of-service study in which the revenue requirements are assigned to each rate class. The class cost-of-service study is discussed later in my testimony.

To meet the RFP requirements, a JCOS is produced on a test year basis, adjusted for known and measurable changes. Schedule A-3 provides the effect of each adjustment on a total company basis. The JCOS study begins with total Company amounts which are then allocated to the Texas jurisdiction as described below.

Q25. WHAT IS REQUIRED TO PRODUCE A JCOS FOR THE TEXAS JURISDICTION?

A. After the functionalization process is complete, jurisdictional responsibility for each cost is then determined through direct or indirect allocations. When a cost benefits more than one of EPE's jurisdictions, it is allocated amongst jurisdictions based on cost causation principles. Operating data are used to develop allocation factors by jurisdictions (i.e., "Texas" and "Other") that correspond to each cost classification factor (demand, energy, and customers). The production allocators used in the JCOS consist of a four-coincident peak average & excess ("4CP-A&E") allocation factor, a four-coincident peak ("4CP") allocation factor, and a twelve-coincident peak average & excess ("12CP -A&E") allocation factor for demand-related costs; an energy allocation factor for energy-related costs; and a customer allocation factor for customer-related costs. A composite labor allocation factor is used to allocate most administrative and general costs. These allocation factors are calculated as percentages (i.e., Texas retail as a percent of Total Company) which are then applied to specific revenue, expense, and rate base items to derive EPE's cost of service for Texas and Other jurisdictions. This allocation is then summarized by the cost-of-service model and forms the basis for allocating items that are not specifically functionalized, such as accumulated deferred income taxes. If costs were incurred to benefit a clearly identifiable jurisdiction, a direct allocation of that component is made (e.g., distribution substations).

Q26. WHAT ARE DIRECTLY ASSIGNED COSTS IN THE JCOS?

A. When a cost is incurred on behalf of only one jurisdiction, that cost is directly assigned to that jurisdiction. For example, solar PPAs necessary to meet New Mexico renewable standards are directly assigned to New Mexico, and Newman Unit 6 is directly assigned to Texas because the costs of that unit are being incurred to serve Texas load. Directly assigned costs include regulatory assets and items affected by the actions of specific regulatory bodies. For example, EPE is required to pay annually to the State of Texas a commission assessment to defray the cost of the PUCT. This fee relates directly to the Texas jurisdiction, and it applies solely to Texas customers. Therefore, in this example, these costs are directly assigned to the Texas jurisdiction in the JCOS.

Q27. WHAT TYPES OF ALLOCATORS ARE USED IN THE JURISDICTIONAL COST-OF-SERVICE STUDY?

A. As mentioned in the FCOS section, EPE uses two types of allocators: "input" and "dynamic." In the JCOS, input allocators include energy, demand, and customer allocators that come from another source and are either imported or manually input into the JCOS model. As prescribed by the NARUC Manual, the dynamic allocators in the JCOS are derived from accounts that have already been allocated using a combination of allocators; the aforementioned examples include Net Plant and Labor.

Q28. HOW ARE THE JURISDICTIONAL ENERGY, DEMAND, AND CUSTOMER ALLOCATION FACTORS DEVELOPED?

A. EPE witness Enedina Soto develops the demand and energy allocators as discussed in her direct testimony. The data for the customer allocators is provided by EPE witness Carrasco. These external allocators are then input into the UISG regulatory module where the COS model can be run to produce the allocated results.

Q29. WERE ANY ADJUSTMENTS MADE TO THE ENERGY AND DEMAND ALLOCATION FACTORS FOR DEDICATED GENERATION FACILITIES?

A. Yes. Consistent with prior EPE rate case filings, adjustments were made to the jurisdictional energy and the production demand allocation factors to reflect purchased power agreements ("PPAs") specific to certain solar facilities in Texas and New Mexico. In addition to the dedicated solar resources, Newman Unit 6 is also being treated as a dedicated resource (assigned 100% to Texas). EPE witness Soto addresses those adjustments in more detail in her Direct Testimony.

Q30. HOW ARE COSTS OF THOSE DEDICATED SOLAR PPAS RECOVERED FROM CUSTOMERS?

A. The cost of energy from four purchased power contracts in New Mexico that were entered into in order to meet renewable portfolio standard ("RPS") requirements are recovered directly from New Mexico customers through the RPS Cost Rider Rate No. 18. In Texas, EPE recovers the costs of energy from the 10-MW Newman Solar PPA from

Texas customers through the fixed fuel factor and the Texas Community Solar program tariff.

Q31. HOW ARE COSTS FROM COMPANY-OWNED SOLAR GENERATION FACILITIES TREATED IN THE JURISDICTIONAL COST OF SERVICE?

A. EPE directly assigns costs of small company-owned solar facilities that are specifically dedicated to a certain state or jurisdiction. For example, the costs of the Company-owned solar generation facility located at EPE's main office located in downtown El Paso is directly assigned to Texas.

Furthermore, EPE does not allocate any costs of Company-owned solar generation facilities that are specifically dedicated to a single customer or voluntary program (i.e., Texas Community Solar program) to Texas. Instead, EPE directly assigns these costs to the "Other" jurisdiction in the JCOS so that none of these costs or related indirect costs are allocated to Texas customers' base rates.

Q32. DOCKET NO. 54403 GRANTING A 10 MW EXPANSION TO EPE'S COMMUNITY SOLAR PROGRAM ORDERED THAT EPE DEMONSTRATE THAT THE COSTS RELATED TO THE COMMUNITY SOLAR EXPANSION ARE NOT SHIFTED TO EPE CUSTOMERS WHO ARE NOT SUBSCRIBERS TO THE PROGRAM. HOW IS EPE COMPLYING WITH THIS ORDER?

A. EPE's JCOS study shows that any costs associated with the community solar program (or the business solar program) are being directly assigned to the "Other" jurisdiction so that none of the direct costs or indirect costs affect the costs allocated to the Texas jurisdiction. Please see exhibit AH-3.

Q33. WHAT ARE THE SOLAR GENERATION FACILITIES THAT EPE DIRECTLY ASSIGNS TO TEXAS?

A. The following solar generation facilities and all related costs are directly assigned to the Texas jurisdiction:

- EPCC Valle Verde;
- Newman Carport;

- Stanton Tower;
- Van Horn;
- Wrangler; and
- System Operations Center.

Q34. WHAT METHOD IS USED FOR ALLOCATING JURISDICTIONAL DEMAND-RELATED COSTS OF PRODUCTION?

A. In this filing, EPE proposes to use the 12CP-A&E methodology for allocating jurisdictional demand related costs of base load generation and 4CP methodology for allocating jurisdictional demand-related costs of peaking generation facilities with the exception of Newman Unit 6, which is directly assigned on a jurisdictional basis. All other generation facilities will continue to be allocated using the 4CP-A&E methodology.

EPE's system peaks during the summer months of June through September. These monthly peak demands are within 10 percent of the annual system peak demand most of the time, as shown in Exhibit AH-2. The production system is designed and built to meet both peak demand and EPE's energy requirements throughout the year. Therefore, EPE determined that the appropriate allocation for demand-related plant-in-service costs of production should be based on 12CP-A&E, 4CP-A&E and a 4CP methodologies.

Q35. WHAT IS THE DIFFERENCE BETWEEN THE 4CP-A&E AND 4CP METHODOLOGIES? HOW ABOUT 12CPA&E?

A. The difference between the 4CP-A&E and the 4CP methodologies lies in how demand components are factored into each of the calculations. The 4CP-A&E methodology consists of both peak demand and annual average-demand components, while the 4CP methodology consists of just the peak-demand component. The 12CP-A&E methodology also uses both peak demand and annual average demand components, except over 12 months. The specific calculations for each allocator are prepared under the supervision of EPE witness Soto.

Q36. WHAT ALLOCATION METHOD WAS USED FOR ALLOCATING JURISDICTIONAL DEMAND-RELATED PLANT-IN-SERVICE COSTS OF

PRODUCTION IN EPE'S PRIOR FILING?

A. In its 2021 rate case, EPE used the 4CP methodology for allocating jurisdictional demand-related plant-in-service costs of its peaking generating facilities (identified as D2PROD in EPE's JCOS study) and the 4CP-A&E methodology for allocating jurisdictional demand-related plant-in-service costs of all other generating facilities (D1PROD).

Q37. WHY HAS EPE DECIDED TO USE A 12CP-A&E ALLOCATION METHOD FOR ALLOCATING JURISDICTIONAL DEMAND-RELATED PLANT-IN-SERVICE COSTS OF ITS BASE LOAD GENERATION FACILITIES?

A. Base load generation is used year-round, and the 12CP-A&E (DPROD12) allocation accounts for the year-round base demand and seasonal peaks which leads to a more equitable cost sharing.

Q38. WHAT ARE THE GENERATION FACILITIES THAT EPE CONSIDERS AS BASE LOAD UNITS FOR COST-ALLOCATION PURPOSES?

A. EPE considers its generation from Palo Verde Generating Station ("PVGS") to be base load generation. Therefore, Palo Verde Units 1, 2, and 3 are considered base load units.

Q39. WHY HAS EPE DECIDED TO USE A 4CP ALLOCATION METHOD FOR ALLOCATING JURISDICTIONAL DEMAND-RELATED PLANT-IN-SERVICE COSTS OF PEAKING GENERATION FACILITIES?

A. EPE's generation facilities are a mix of base load, load-following and peaking units. The peaking units were primarily designed to be ramped up and down as needed to meet load fluctuations, especially during peak summer hours. Unlike the other units, these facilities are not designed to run for extended periods of time. Therefore, the peaking units can be expected to be operating at high load during the times of EPE's system peak and for load following, but not necessarily during native system off-peak times (such as during the night). As described earlier in my testimony, EPE's system peaks during the four summer months of June through September. Please refer to the direct testimony of EPE witness David Rodriguez for descriptions of EPE's generation fleet's operation and performance.

Q40. WHAT ARE THE GENERATION FACILITIES THAT EPE CONSIDERS AS PEAKING UNITS FOR COST-ALLOCATION PURPOSES?

A. EPE considers the following generation facilities as peaking units:

- Montana Power Station Units 1 through 4,
- Newman Unit 6;
- Rio Grande Generating Station Unit 9, and
- Copper Generating Station.

With the exception of Newman Unit 6, which EPE is proposing to direct assign (100%) to Texas, the rest of the peaking units are allocated using the 4CP allocator "D2PROD" in the JCOS.

Q41. WHAT ALLOCATOR IS USED FOR ALLOCATING JURISDICTIONAL PLANT-IN-SERVICE COSTS FOR TRANSMISSION?

A. EPE's transmission plant is treated by EPE as a single system that serves all jurisdictions regardless of geographic location. Because transmission is primarily built to meet the peak demand of EPE's service territory, and is not affected by energy needs, transmission plant-in-service costs are allocated on the 4CP methodology. The 4CP allocator D2TRAN reflects the need for this transmission during the four summer months of June through September, when EPE's system peak demands occur.

Q42. HOW ARE DISTRIBUTION PLANT-IN-SERVICE COSTS JURISDICTIONALLY ALLOCATED?

A. Distribution plant-in-service costs in the JCOS study are directly assigned based on geographic location. The only exception is for any distribution plant costs related to the previously discussed solar facilities that are dedicated to a single customer.

Q43. HOW IS EPE ALLOCATING METERS TO EACH JURISDICTION?

A. EPE's advanced meters are currently recovered through a separate rider. In Texas, the advanced meters are recovered through the AMS Surcharge, and they are directly assigned to "Other" so that those costs are not included in EPE's calculation of Texas base rates.

Texas legacy meters (identified as Unrecovered Plant and Regulatory Study Costs in Schedules B-1 and B-1.1) are direct assigned to Texas as they will continue to be recovered in base rates until fully depreciated.

Q44. HOW ARE GENERAL PLANT-IN-SERVICE COSTS JURISDICTIONALLY ALLOCATED?

A. General plant-in-service costs are allocated using a labor allocation factor which is derived from payroll costs included within the production, transmission, distribution, and customer service functions. Since EPE's COS starts with the FCOS study, the JCOS applies functionalized labor allocators such as PRODLABOR, TRANLABOR, DISTLABOR, and CUSTLABOR.

Q45. HOW DOES EPE DEVELOP THE LABOR ALLOCATION FACTOR?

A. The LABOR allocation factor is developed using a composite of EPE's functionalized operation and maintenance ("O&M") labor expenses, excluding A&G labor expenses. In other words, this dynamic allocator is derived from the payroll amounts (wages and salaries) found within the functional O&M accounts ranging from 500 through 905. These labor O&M expenses are allocated to each function then to each jurisdiction (then DEC component and rate class) based on their respective functional (production, transmission, distribution, or customer) allocators. The JCOS utilizes the functionalized labor allocators mentioned above.

Q46. HOW ARE INTANGIBLE PLANT-IN-SERVICE COSTS JURISDICTIONALLY ALLOCATED?

A. Intangible plant-in-service costs are allocated using an allocation factor commensurate with the function that such intangible plant is associated with (i.e., production, transmission, distribution, and customer service functions).

Q47. HOW IS THE ACCUMULATED DEPRECIATION RELATED TO THE

PLANT-IN-SERVICE COSTS JURISDICTIONALLY ALLOCATED?

A. Accumulated depreciation amounts are allocated using an allocation factor commensurate with the plant-in-service function that these amounts are associated with.

Q48. HOW ARE WORKING CAPITAL AMOUNTS JURISDICTIONALLY ALLOCATED?

A. Materials and Supplies are allocated according to the function specified in the account code block descriptions. Fuel inventory is allocated with E2ENERGY. Prepayments are allocated according to the function specified in the account code block description. Working Cash is calculated within the UISG regulatory solution, but the calculation uses the allocated jurisdictional result of its components (e.g., O&M, taxes, etc.).

Q49. IS THERE A SCHEDULE THAT SHOWS EPE'S JURISDICTIONAL RATE BASE?

A. Yes. Schedule B-1.1 presents EPE's jurisdictional rate base.

Q50. HOW ARE DEMAND-RELATED PRODUCTION O&M EXPENSES ALLOCATED TO EACH JURISDICTION?

A. Demand-related production O&M expenses are allocated based on either the 4CP-A&E, 4CP, or 12CP-A&E allocator, identified in the JCOS model as D1PROD, D2PROD, and DPROD12, respectively. The D1PROD allocator is applied to O&M expenses of load-following generating facilities, and the D2PROD allocator is applied to O&M expenses of the peaking generating facilities. The DPROD12 allocator is applied to O&M expenses of PVGS and to system control and dispatch expenses. Finally, EPE treats imputed capacity costs and other non-reconcilable purchase power costs (i.e., spinning reserves) as demand-related costs so it allocates those costs with the D1PROD allocator.

Q51. ARE THERE ANY ENERGY-RELATED PRODUCTION O&M EXPENSES?

A. Yes. Production O&M expenses that vary on the amount of energy produced are considered energy related. There are two types of energy-related production O&M expenses. The first type is fuel and purchased power expenses which are recovered through EPE's Texas Fixed Fuel Factor ("TX FFF"). The second type of energy-related expenses are recovered in base rates.

Q52. WHAT ARE THE DIFFERENT ENERGY ALLOCATORS AND HOW ARE THEY DEVELOPED?

A. EPE uses three different external allocators to allocate energy-related costs: E1ENERGY, E1FUEL, and E2ENERGY. E1ENERGY is used to allocate energy-related non-fuel production O&M expenses. E1FUEL is used to allocate fuel and purchased expenses. E2ENERGY is used to allocate costs that may be fuel-related or driven by a fuel-related activity but are not recovered through the TX FFF (i.e., fuel inventory or deferred taxes).

EPE witness Soto develops the E1ENERGY allocator using kWh at supply excluding non-firm (interruptible) kWh. The E1FUEL and E2ENERGY allocators are also developed by EPE witness Soto using all kWh at supply (including non-firm).

Q53. HOW ARE ENERGY-RELATED PRODUCTION O&M EXPENSES ALLOCATED TO EACH JURISDICTION?

A. As discussed above, non-fuel O&M expenses are allocated to each jurisdiction on E1ENERGY. Reconcilable fuel and purchased power expenses are all allocated using E1FUEL. Non-reconcilable fuel and purchased power expenses that are not demand-related (such as the imputed capacity or spinning reserves discussed above) would be allocated using the E2ENERGY allocator.

Q54. IS EPE ALLOCATING PRODUCTION O&M DIFFERENTLY IN THIS CASE COMPARED TO ITS PREVIOUS RATE CASE?

A. Yes, similar to production plant, demand related O&M expenses will be allocated using the 4CP, 4CP-A&E, or 12CP-A&E depending on the type of generation or direct-assigned depending on the specific generation facility.

Q55. HOW ARE TRANSMISSION O&M EXPENSES ALLOCATED AMONG THE JURISDICTIONS?

A. Most transmission O&M expenses are allocated based on the 4CP method. The 4CP allocator is identified as D2TRAN. The only exception is for FERC Account 561 – Load

Dispatching. Load dispatching costs are incurred year-round; therefore, these costs are allocated using a 12CP allocator, DTRAN12.

Q56. HOW ARE DISTRIBUTION O&M EXPENSES JURISDICTIONALLY ALLOCATED?

A. Distribution O&M expenses are either: (1) directly assigned to the respective jurisdiction that the expenses were incurred for; or (2) allocated based on their respective plant investment in each jurisdiction; or (3) allocated on a dynamic allocator based on the costs contained in the other accounts of the operation or maintenance account grouping.

Q57. HOW ARE CUSTOMER ACCOUNTS AND CUSTOMER SERVICE & INFORMATION O&M EXPENSES ALLOCATED TO EACH JURISDICTION?

A. Customer Accounts and Customer Service & Information O&M expenses that are directly assignable are determined and directly assigned to the applicable jurisdiction, and the remaining accounts are allocated using customer-based allocators or through use of a dynamic allocator based on the costs contained in the other accounts of the account grouping. The only exception is FERC Account 904 – Uncollectible Accounts which is allocated using the firm base and fuel revenues of all customer classes except Other Public Authority and Commercial and Industrial (C&I) Large in each jurisdiction (UNCOLL_REVS).

EPE's allocation of uncollectible expense takes guidance from the Company's accounts receivable aging schedule to estimate bad debts. EPE's policy excludes Other Public Authority and C&I Large customers from the aging schedule. Therefore, EPE's allocation of uncollectible expense excludes them too.

Q58. HOW ARE ADMINISTRATIVE AND GENERAL ("A&G") EXPENSES ALLOCATED AMONG THE JURISDICTIONS?

A. Most A&G expenses are allocated to a jurisdiction based on the LABOR allocation factor or another labor related allocation factor derived from the labor expenses contained in the accounts of the applicable functional account grouping. A&G expenses related to a specific function (e.g., production, transmission, distribution) are allocated based on the function's assigned allocator. If an expense can be identified as benefiting a specific jurisdiction, then that expense is directly assigned to that jurisdiction (such as Regulatory Commission fees recorded in FERC Account 928 – Regulatory Commission Expenses).

Q59. HOW ARE THE DEPRECIATION AND AMORTIZATION EXPENSES JURISDICTIONALLY ALLOCATED?

A. EPE jurisdictionally allocates depreciation and amortization expenses by function consistent with the allocation of plant-in-service amounts.

The amortization expenses that are directly assignable to a jurisdiction were first determined and assigned. The remaining amortization expenses related to a specific function (e.g., production, transmission, distribution) are allocated based on the function's assigned allocator. Otherwise, they are allocated using the LABOR allocation factor.

Q60. HOW IS THE AMORTIZATION OF LEGACY METERS ALLOCATED TO EACH JURISDICTION?

A. The amortization associated with legacy meters (identified as Amortization of Unrecovered Plant in Schedules A and A-1) is direct assigned consistent with the jurisdiction of those legacy meters.

Q61. HOW ARE REGULATORY DEBITS AND CREDITS ALLOCATED TO EACH JURISDICTION?

A. Regulatory debits and credits are directly assigned to each jurisdiction as specifically mandated by each jurisdiction's utility commission.

Q62. HOW ARE INCOME TAXES ALLOCATED TO EACH JURISDICTION?

A. Federal and state income taxes are split into two categories, current and deferred. Deferred federal and state income tax expenses are assigned an allocator based upon the underlying Schedule M item of the deferred income tax in the regulatory module. Deferred federal and state income taxes are mostly allocated using dynamic allocators like NETPLT, but various allocators are used depending on the Schedule M item descriptions in the tax repository. Current federal and state income taxes are calculated in the UI regulatory module based on the allocated results of rate base and operating income. EPE witness Tamera Henderson discusses the calculation of the Company's income taxes.

Q63. HOW ARE TAXES OTHER THAN INCOME TAXES ALLOCATED TO EACH JURISDICTION?

A. Payroll and unemployment taxes are allocated to jurisdictions based on the LABOR allocation factor. Jurisdictional allocation of property taxes is consistent with how each plant-in-service functional grouping is allocated. Revenue-related taxes are directly assigned to the jurisdiction in which such taxes are assessed; therefore, the Texas jurisdiction is not allocated any New Mexico revenue-related taxes. Other taxes such as sales and use taxes are allocated based on the allocation of gross plant.

Q64. IS THERE A SCHEDULE THAT SHOWS EPE'S EXPENSES ON A JURISDICTIONAL BASIS?

A. Yes, Schedule A-1 summarizes EPE Jurisdictional Cost-of-Service.

Q65. BASED ON THE JURISDICTIONAL COST-OF-SERVICE STUDY YOU HAVE DISCUSSED, WHAT IS THE TEXAS REVENUE REQUIREMENT THAT EPE IS REQUESTING IN THIS CASE?

A. With reference to Schedule A-1 and Table 1 below, EPE has calculated a total revenue requirement for the Texas jurisdiction of $934.4 million. After adjusting that amount for fuel revenues and other operating revenues, the remaining $713.3 million base rate revenue requirement exceeds current annualized retail base revenue by $85.7 million (or 13.7 percent). The following table shows the results of the Texas jurisdictional cost of service:

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**Table 1**

| Line | Description | Amount |
|---|---|---|
| 1 | Total Rate Base | $2,733,746,541 |
| 2 | Weighted Average Cost of Capital ("WACC") | 8.363% |
| 3 | Return on Rate Base | $228,624,234 |
| 4 | Fuel and Purchased Power | $182,113,982 |
| 5 | Operation and Maintenance (O&M) | $246,018,803 |
| 6 | Regulatory Debits and Credits | $0 |
| 7 | Depreciation & Amortization | $139,636,359 |
| 8 | Decommissioning and Accretion | $3,291,269 |
| 9 | Amortization of Unrecovered Plant | $1,202,522 |
| 10 | Taxes Other Than Income | $84,882,654 |
| 11 | Federal Income Taxes | $40,041,615 |
| 12 | State Income Taxes | $8,544,961 |
| **13** | **Total Cost of Service** | **$934,356,399** |
| 14 | Less: Other Operating Revenues | ($42,462,287) |
| 15 | Less: Fuel Revenues and Sales for Resale | ($178,599,049) |
| **16** | **Base Rate Revenue Requirement** | **$713,295,063** |
| 17 | Less: As Adjusted Base Revenues | ($627,629,349) |
| **18** | **Base Rate Revenue Deficiency** | **$85,665,713** |
| 19 | Percent Increase | 13.65% |

Exhibit AH-3 presents an overall summary of the JCOS study.

EPE's As Adjusted Base Revenues of $627,629,349 (shown on line 17 of Table 1 above) reflect the known and measurable adjustments that are discussed in more detail in the direct testimony of EPE witness Rene Gonzalez.

Q66. WHAT IS THE FIRM BASE REVENUE REQUIREMENT FOR THE TEXAS JURISDICTION THAT EPE IS REQUESTING IN THIS CASE?

A. As shown in Schedule A-1 (column f, line 1), the firm base revenue requirement (the amount net of revenue requirement expected to be provided by non-firm revenues, such as interruptible load) is $709,750,728. The firm base revenue increase is 13.73% ($85,665,713 base revenue deficiency from the adjusted firm base revenues of $624,085,014, which excludes the non-firm revenues). The firm base revenues calculated in the CCOS and DEC studies (at an equalized rate of return) will be discussed later and are provided to EPE witness Carrasco to develop EPE's proposed rates.

## VI. Demand, Energy, and Customer Components Study

Q67. PLEASE DESCRIBE THE DEMAND, ENERGY, AND CUSTOMER COMPONENTS STUDY.

A. The Demand, Energy, and Customer Components Study ("DEC Study") is the third step in the process after the functional and jurisdictional cost-of-service studies. The DEC Study allocates costs to each of the DEC components. These DEC results along with the rate class results (discussed later in my testimony) are essential in developing rates and are provided to EPE witness Carrasco for developing proposed rates.

Q68. HOW DO THE FUNCTIONALIZED COSTS IDENTIFIED IN PREVIOUS STEPS RELATE TO THE COSTS PRESENTED IN THE DEC STUDY?

A. The functionalized costs of Production, Transmission, Distribution, and Customer are classified into Demand, Energy, and Customer components in the DEC Study as shown in Table 2.

**Table 2**

| Cost Functions | Cost Classifications |
|---|---|
| Production | Demand Related<br>Energy Related |
| Transmission | Demand Related |
| Distribution | Demand Related<br>Customer Related |
| Customer | Customer Related |

Q69. WHAT ARE THE SPECIFIC COMPONENTS PRESENTED IN THE DEC STUDY THAT MAKE UP THE DEMAND, ENERGY, AND CUSTOMER CLASSIFICATIONS?

A. The components are shown in Table 3 below.

**Table 3**

| Demand | Energy | Customer |
|---|---|---|
| Demand - Production | Energy - Other | Customer - Other |
| Demand - Transmission | Energy - Fuel | Customer - Deposits |
| Demand - Distribution | | Customer - 369 Services |
| - Dem Dist - Load Dispatching | | Customer - 370 Meters |
| - Dem Dist - Poles Towers Fixtures - Primary | | Customer - 371 Install on Customer Premise |
| - Dem Dist - Poles Towers Fixtures - Secondary | | Customer - 373 Street Lighting |
| - Dem Dist - Overhead Lines - Primary | | Customer - 902 Meter Reading |
| - Dem Dist - Overhead Lines - Secondary | | Customer - 903 Customer Rec & Collections |
| - Dem Dist - Underground Lines - Primary | | |
| - Dem Dist - Underground Lines - Secondary | | |
| - Dem Dist - Line Transformers - Primary | | |
| - Dem Dist - Line Transformers - Secondary | | |

Q70. HOW IS PRODUCTION PLANT-IN-SERVICE CLASSIFIED?

A. Production plant is classified as demand related. Therefore, all production plant accounts fall under the Demand Production component.

Q71. HOW IS TRANSMISSION PLANT-IN-SERVICE CLASSIFIED?

A. Transmission plant is classified as demand related, and all transmission plant accounts fall under the Demand Transmission component.

Q72. HOW IS DISTRIBUTION PLANT-IN-SERVICE CLASSIFIED?

A. Distribution investments serve customer demands as well as providing a basic investment uniformly common to all customers. For this reason, Distribution plant will have both a Demand component and a customer component as seen on Table AH-3.

Distribution Plant Account No. 360 - Land and Land Rights, Account No. 361 - Structures and Improvements, and Account No. 362 - Station Equipment are allocated to the Distribution-Load Dispatching component of Demand. Distribution Plant Account No. 364 - Poles is assigned to the Distribution-Poles, Towers, and Fixtures ("PTF") component of Demand. Account No. 365 - Overhead Conductors is assigned to the

Distribution-Overhead component of Demand. Account No. 366 - Underground Conductors and Account No. 367 - Underground Conduits are assigned to the Distribution-Underground component of Demand. All of these are separated based on the distribution voltage level served, either primary or secondary. Account No. 368 - Line Transformers is also separated based on the distribution voltage level served, either primary or secondary. It is assigned to the Distribution-Transformer component of Demand.

Account No. 369 - Services is classified as a customer-related cost and falls under the Customer - 369 Services component under Customer. Account No. 370 - Meters is classified as a customer-related cost and it falls under the Customer No. 370 - Meters component under Customer.

Q73. HOW ARE GENERAL PLANT-IN-SERVICE COSTS ALLOCATED TO DEC COMPONENTS?

A. Similar to how general plant costs in the CCOS study are allocated on the LABOR allocation factor (which functionalizes the costs based on O&M labor), general plant costs in the DEC Study are spread among the DEC components the same way.

Q74. HOW IS WORKING CAPITAL ALLOCATED IN THE DEC STUDY?

A. Fuel inventory is allocated with the E2ENERGY allocator. Prepayments and Materials and Supplies are allocated with different allocators based on the functional account descriptions. Consistent with the previous steps in the COS, the calculation of Working Cash in UISG uses the allocated DEC results.

Q75. IS THERE A SCHEDULE THAT SHOWS HOW ALL RATE-BASE AMOUNTS ARE ASSIGNED TO DEMAND, ENERGY, AND CUSTOMER?

A. Yes. Schedule P-5 itemizes all the rate base costs and presents them by the Demand, Energy, and Customer classifications, along with the allocator that was applied for the assignment.

Q76. HOW ARE POWER PRODUCTION EXPENSES CLASSIFIED?

A. Fuel and purchased power expenses do not have a base-rate impact since they are recovered (off-set) by fuel-related revenues. All fuel-related expenses and revenues are assigned to the Energy-Fuel component. The remaining non-fuel, energy-related costs are assigned to the Energy-Other component. The demand-related production O&M costs like load-dispatching costs are assigned to the Demand Production component.

Q77. HOW ARE TRANSMISSION O&M EXPENSES CLASSIFIED?

A. Similar to Transmission plant, all Transmission O&M expenses fall under the Transmission component of Demand.

Q78. HOW ARE DISTRIBUTION O&M EXPENSES ALLOCATED TO DEC COMPONENTS?

A. Similar to the CCOS study, Distribution O&M expenses are allocated based on the related distribution plant account allocation. An exception is when using a blended allocator for supervision and engineering accounts and the miscellaneous distribution expense. Also, rents are allocated based on total distribution plant as in the CCOS study. Similar to distribution plant, distribution O&M expenses will have both Demand and Customer components.

Q79. HOW ARE CUSTOMER SERVICE EXPENSES CLASSIFIED?

A. All customer service expenses will be classified as Customer-related. Account No. 902 - Meter Reading Expense is assigned to the Customer - 902 Meter Reading component. Account No. 903 - Customer Record & Collections is assigned to the Customer – 903 - Customer Rec & Collections component. Account No. 904 - Uncollectible Accounts, Account No. 905 - Misc. Customer Accounts Expenses, and Account No. 909 - Informational and Instructional Advertising Expenses are all classified under the Customer – Other component.

Q80. HOW ARE ADMINISTRATIVE AND GENERAL EXPENSES ALLOCATED TO DEC COMPONENTS?

A. Similar to the CCOS, if the A&G account code block description is detailed enough, allocation of such costs can be determined by function and classification. The remaining A&G expenses in which a specific function cannot be determined are allocated on the LABOR allocation factor spreading the costs among Demand, Energy, and Customer components.

Q81. HOW DOES EPE ALLOCATE DEPRECIATION AND AMORTIZATION EXPENSES TO DEC COMPONENTS?

A. EPE allocates depreciation and amortization expenses by the function consistent with the allocation of the associated plant and accumulated depreciation accounts.

Q82. HOW ARE INCOME TAXES ALLOCATED TO DEC COMPONENTS?

A. Consistent with the FCOS and JCOS, deferred income taxes are allocated using a net plant allocator unless another function is specified in the account and current income taxes are calculated by DEC component.

Q83. HOW ARE TAXES OTHER THAN INCOME TAXES ALLOCATED TO DEC COMPONENTS?

A. Payroll and unemployment taxes are allocated based on a functional labor allocation factor. Assignment of property taxes to each DEC component is consistent with how each plant in service functional grouping is allocated. Revenue-related taxes are allocated on a functional rate base allocator if they are associated with a specific function, or they are assigned to a specific component such as Customer-Other where they will later be allocated to rate classes by a revenue allocator. Other taxes such as sales and use taxes are allocated based on a gross plant allocator.

Q84. IS THERE A SCHEDULE THAT PRESENTS HOW THE EXPENSES ARE ASSIGNED TO DEMAND, ENERGY, AND CUSTOMER?

A. Yes. Schedule P-4 itemizes all of the expenses along with the allocator and presents them by the Demand, Energy, and Customer classifications.

## VII. Class Cost-of-Service Study

Q85. PLEASE DESCRIBE THE TEXAS RETAIL CLASS COST-OF-SERVICE STUDY MODEL.

A. The Texas retail class cost-of-service study model is the result of first producing the FCOS, JCOS, and DEC studies. In the class cost-of-service study, the full functionalized and classified Texas revenue requirements are assigned to each of the rate classes on a cost-causative basis. The CCOS provides the revenue and cost data for EPE's Texas service area that is required for preparation of the P schedules.

Q86. WHAT IS REQUIRED TO PRODUCE A CCOS FOR THE TEXAS JURISDICTION?

A. Class responsibility for each cost is determined through direct assignments or allocations. Operating data are used to develop allocation factors by rate class that correspond to each cost classification factor (demand, energy, and customers). These allocation factors are calculated as percentages (i.e., Residential class as a percent of total Texas) which are then applied to specific revenue, expense, and rate-base items in the derivation of EPE's cost of service for Texas retail rate classes. This allocation is then summarized by the cost-of-service model and forms the basis for assigning items that are not specifically functionalized, such as accumulated deferred income taxes. If costs were incurred to benefit a clearly identifiable rate class, a direct assignment of that component is made (e.g., street lighting).

Q87. WHAT ARE DIRECTLY ASSIGNED COSTS?

A. Directly assigned costs consist of those costs that are incurred specifically for certain rate classes. For example, EPE incurs costs for operating and maintaining streetlights (such as replacing burnt lamps); therefore, these costs are directly assigned to the Street-lighting rate class in the CCOS.

Q88. WHAT TYPES OF ALLOCATORS ARE USED IN THE CLASS COST-OF-SERVICE STUDY?

A. Similar to the JCOS, the regulatory model utilizes two general types of allocators: imported or "external" allocators, and dynamic or "internal" allocators for the CCOS.

However, the recent changes to EPE's cost of service limits the need to use dynamic allocators since in many cases, the function and DEC components of the costs are already known such that the use of more direct external allocators can be used instead.

Q89. IS EPE PROPOSING TO ADD OR REMOVE ANY RATE CLASSES IN THIS PROCEEDING?

A. No, EPE's CCOS in this proceeding will not add or remove any new rate classes. However, refer to EPE witness Carrasco's direct testimony on new rate proposals.

Q90. WHAT METHOD IS USED TO ASSIGN THE DEMAND-RELATED COSTS OF THE PRODUCTION PLANT-IN-SERVICE TO EACH RATE CLASS?

A. As explained in the JCOS section, in this filing, EPE proposes to use the 12CP-A&E methodology (DPROD12) for assigning demand-related costs of EPE's base load generation, 4CP methodology (D2PROD) for assigning demand-related costs of peaking generation facilities, and the 4CP-A&E methodology (D1PROD) for assigning demand-related costs of all other generation facilities. The CCOS uses these allocators to assign demand-related production costs to each rate class.

Q91. HOW ARE THE DEMAND-RELATED COSTS OF TRANSMISSION PLANT-IN-SERVICE ASSIGNED TO EACH RATE CLASS?

A. Consistent with the JCOS study, transmission plant is assigned to each rate class using the 4CP allocator D2TRAN.

Q92. HOW IS THE DEMAND-RELATED COST OF DISTRIBUTION PLANT-IN-SERVICE ASSIGNED TO EACH RATE CLASS?

A. EPE uses the Maximum Class Demand ("MCD") to assign substation and primary distribution feeder system costs and Non-Coincident Peak Demand ("NCP") to assign secondary voltage distribution feeders and line transformer costs.

Q93. HOW ARE MCD AND NCP DEVELOPED, AND WHAT DO THEY REPRESENT?

A. EPE witness Soto develops the MCD and NCP. In general, MCD represents the diversified loads of a rate class at the system peak; NCP represents the summation of the maximum loads of each customer within a rate class.

Q94. WHY DOES EPE USE BOTH THE MCD AND NCP ALLOCATORS FOR DISTRIBUTION PLANT?

A. These distribution plant allocators are based on the level of voltage service received. The cost causation for the distribution system differs for each voltage level; therefore, EPE developed allocation factors for each of these levels to reflect the type of loads that most significantly influence the costs at that level. The MCD is appropriate for the primary voltage plant because the primary distribution system serves all distribution level customers. The NCP Demand allocator is a measurement of maximum attainable peak demand by each rate class, independent of the class or system peak. This method allocates costs to serve customers based on their diversity at the more localized secondary distribution system.

Q95. HOW ARE DISTRIBUTION PLANT-IN-SERVICE ACCOUNTS RELATED TO SUBSTATIONS (NOS. 360 THROUGH 362) ASSIGNED TO EACH RATE CLASS?

A. Distribution Plant Account No. 360 - Land and Land Rights, Account No. 361 - Structures and Improvements, and Account No. 362 - Station Equipment costs are assigned based on the MCD allocator described previously. The MCD allocator (D3DIST, D4DIST, D7DIST, or D9DIST) reflects the responsibility and costs to the customers served downstream from substations.

Q96. HOW ARE DISTRIBUTION PLANT-IN-SERVICE ACCOUNT NOS. 364 THROUGH 368 ASSIGNED TO RATE CLASSES?

A. Distribution Plant Account No. 364 - Poles, Account No. 365 - Overhead Conductors; Account No. 366 - Underground Conductors and Account No. 367 - Underground Conduits; and Account No. 368 - Line Transformers costs are separated based on the distribution voltage level served, either primary or secondary. The primary voltage level costs are assigned to rate classes using the MCD allocator. The secondary voltage level costs are assigned based on the NCP allocator (D5DIST, D6DIST, D8DIST, or D10DIST).

Q97. HOW IS THE CUSTOMER-RELATED COST OF DISTRIBUTION PLANT-IN-SERVICE ASSIGNED TO EACH RATE CLASS?

A. EPE also assigns costs for services on a service drop investment allocator ("SDI") and costs for meters based on a weighted meter cost allocator ("METER"). Legacy Meters will be allocated using a new allocator, ("LEGACY_METER"). Lighting-related facilities are directly assigned to the associated rate class such as street lighting or private area lighting.

Q98. HOW DOES EPE ASSIGN COSTS FOR ACCOUNT NO. 369 – SERVICES TO EACH RATE CLASS?

A. Account No. 369 – Services, e.g., costs of service drop from the distribution system to serve customers, is assigned to rate classes based on the SDI allocator. This method creates an allocator based on the number of services per rate class weighted by the typical cost to provide a service drop to that rate class.

Q99. WHAT ASSIGNMENT METHOD DOES EPE USE FOR ACCOUNT NO. 370 - METERS?

A. EPE uses the METER or LEGACY_METER allocator to better reflect the cost causation based on the differing meter costs among the classes. Therefore, the count of meters for each rate class is weighted by the typical cost of a meter. This procedure assigns meter costs to each class proportional to the class and level of service directly impacted by these costs.

For example, customer classes with larger per-customer loads typically use a more technologically advanced meter (e.g., Interval Data Recorder meter). These meters are more expensive than a simple residential energy measuring meter, thus a greater weight is applied to such meters.

Q100. HOW ARE GENERAL PLANT-IN-SERVICE COSTS ASSIGNED TO EACH RATE CLASS?

A. Since the allocated results of general plant from prior steps are already known by Function and DEC component, the assignment of allocators in the rate class step can be more specifically allocated with demand, energy, or customer allocators.

Q101. HOW ARE INTANGIBLE PLANT-IN-SERVICE COSTS ASSIGNED TO RATE CLASSES?

A. Intangible plant-in-service costs are allocated to rate classes using an allocation factor commensurate with the function and DEC Component that were determined in the prior cost of service steps.

Q102. HOW IS THE ACCUMULATED DEPRECIATION RELATED TO THE PLANT-IN-SERVICE COSTS ASSIGNED?

A. Accumulated depreciation amounts are assigned to each rate class using an allocation factor commensurate with the plant account that these amounts are associated with.

Q103. HOW ARE WORKING CAPITAL AMOUNTS ASSIGNED TO EACH RATE CLASS?

A. Materials and Supplies are allocated according to the function specified in the account code block description. Fuel inventory is allocated with E2ENERGY. Prepayments are allocated according to the function specified in the account code block description. Consistent with the allocation in the JCOS, Working Cash is calculated using the allocated results of its components (e.g., O&M, taxes, etc.).

Q104. IS THERE A SCHEDULE THAT SHOWS HOW ALL RATE-BASE AMOUNTS ARE ASSIGNED TO EACH RATE CLASS?

A. Yes. Schedule P-3 itemizes all the rate-base costs and presents the rate class assignment of each cost, along with the allocator that was applied for the assignment.

Q105. HOW ARE POWER PRODUCTION EXPENSES ASSIGNED TO EACH RATE CLASS?

A. Reconcilable fuel and purchased power related expenses are allocated on the energy allocator E1FUEL. Non-fuel energy-related power production expenses are allocated using E1ENERGY. The remaining demand-related power production expenses are allocated based on either the 4CP-A&E allocator (D1PROD); 4CP allocator (D2PROD);

or 12CP-A&E allocator (DPROD12).

Q106. HOW ARE TRANSMISSION O&M EXPENSES ASSIGNED TO EACH RATE CLASS?

A. Consistent with the JCOS, FERC Account 561 – Load Dispatching expenses are allocated using a 12CP allocator (DTRAN12). All other transmission O&M expenses are assigned to each rate class with the D2TRAN allocator.

Q107. HOW ARE DISTRIBUTION O&M EXPENSES ASSIGNED TO EACH RATE CLASS?

A. Generally, the Distribution O&M costs are assigned to each rate class based on the related distribution plant account allocation. Since the DEC Components are known in the CCOS step, the process of assigning rate class allocators to distribution O&M costs is simplified. For example, Account No. 580 - Supervision and Engineering and Account No. 588 - Misc. Distribution Expenses used to be allocated on dynamic allocator EXP_5817 (based on Accounts 581 through 587), but now a direct allocator assignment can be made based on the known DEC Component results of these accounts.

Q108. HOW ARE CUSTOMER ACCOUNTS (ACCOUNT NOS. 901 – 905) AND CUSTOMER SERVICE & INFORMATION O&M (ACCOUNT NOS. 906 – 910) EXPENSES ASSIGNED TO EACH RATE CLASS?

A. Account No. 901 - Supervision is assigned to each rate class using a dynamic allocator based on the expenses contained in the other accounts of the account grouping. Account No. 902 - Meter Reading Expenses are based on a meter-related allocation factor, while Account Nos. 903 - Customer Records and Collections, 905 - Miscellaneous Customer Expenses, and 909 - Informational and Instructional Advertising Expenses are assigned to rate classes using a customer-count allocation factor. Major account representative labor expenses in FERC Account 903 are allocated based on the number of customers in nonresidential rate classes.

As previously discussed, Account No. 904 - Uncollectible Accounts expenses are assigned based on the firm base and fuel revenues of each rate class, except for those rate classes that are not subject to account write-offs such as governmental customers or C&I Large customers.

Q109. HOW ARE ADMINISTRATIVE AND GENERAL EXPENSES ASSIGNED TO EACH RATE CLASS?

A. In the past, most A&G expenses were assigned to rate classes using a labor-related allocation factor derived from the payroll expenses contained in the accounts of the applicable functional account grouping. However, for A&G expenses in the CCOS it is now known which function or DEC Component each cost is related to so a specific allocator can be assigned.

Q110. HOW ARE THE DEPRECIATION AND AMORTIZATION EXPENSES ASSIGNED TO EACH RATE CLASS?

A. EPE assigns to each rate class depreciation and amortization expenses by function consistent with the assignment of the respective plant-in-service and accumulated depreciation accounts.

Q111. HOW ARE REGULATORY DEBITS AND CREDITS ASSIGNED TO EACH RATE CLASS?

A. If there are any Regulatory debits and credits assigned to the Texas jurisdiction, they are allocated depending on the function or DEC component of the specific debits and credits.

Q112. HOW ARE TAXES OTHER THAN INCOME TAXES ASSIGNED TO EACH RATE CLASS?

A. Payroll and unemployment taxes are assigned to rate classes based on the function or DEC component. Assignment of property taxes to each rate class is consistent with how each plant-in-service functional grouping is allocated. Revenue-related taxes are based on a dynamic revenue allocation factor. Other taxes such as sales and use tax were allocated with a gross plant allocator in the past, but now they can be allocated more directly using the function and DEC classification.

Q113. HOW ARE INCOME TAXES ALLOCATED TO EACH RATE CLASS?

A. The deferred federal and state income taxes are allocated using the function and DEC classification. Current federal and state income taxes are calculated at the rate class level in the model like they were in previous steps of the COS.

Q114. IS THERE A SCHEDULE THAT SHOWS HOW EXPENSES ARE ASSIGNED TO RATE CLASSES?

A. Yes. Schedule P-2 itemizes all the expenses and presents the assignment of each expense to each rate class and provides the allocator that was applied for the assignment.

Q115. HOW DOES THE CCOS ALLOCATE THE NON-FIRM, FUEL, AND OTHER OPERATING REVENUES TO EACH RATE CLASS?

A. Non-firm revenue is allocated to rate classes using the D2PROD allocator. The reason is because non-firm revenues from interruptible customers are used in order to reduce peak demand. As previously discussed, D2PROD is the 4CP allocator used to allocate peaking-generation units.

Fuel revenues are adjusted to match the reconcilable fuel and purchased power expenses of each rate class, net of off-system sales. The reconcilable fuel and purchased power expenses and off-system sales fuel costs are allocated to each rate class with the E1FUEL allocator.

Other Operating Revenues are allocated to each rate class with various allocators depending on the function specified. For example, Miscellaneous Service Revenues are allocated with the distribution or customer-related allocators and Forfeited discounts are allocated similar to uncollectible expense. Provision for Refund revenues are allocated on D2TRAN.

EPE's revenues are discussed in the Direct Testimony of EPE witness Rene Gonzalez. These revenues (non-firm, fuel-related, and other operating revenues) are credited against the Total Cost of Service to arrive at the firm Base Rate Revenue Requirement of each rate class.

Q116. HOW IS THE CLASS COST-OF-SERVICE STUDY PRESENTED IN THE FILING?