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APPLICATION OF EL PASO ELECTRIC COMPANY TO CHANGE RATES	**§ § §**	**BEFORE THE STATE OFFICE OF ADMINISTRATIVE HEARINGS**

CROSS-REBUTTAL TESTIMONY

AND

WORKPAPERS

OF

EVAN D. EVANS

ON BEHALF OF THE

OFFICE OF PUBLIC UTILITY COUNSEL

COST ALLOCATION / RATE DESIGN PHASE

November 19, 2021

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CROSS-REBUTTAL TESTIMONY AND WORKPAPERS OF EVAN D. EVANS

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ACRONYMS AND ABBREVIATIONS

1CP	1 Coincident Peak
4CP	4 Coincident Peak
4CP-A&E	4 Coincident Peak - Average and Excess
12CP	12 Coincident Peak
AED	Average and Excess Demand
ASLF	Annual System Load Factor
CAM	Cost Allocation Manual
EPCC	El Paso Community College
EPE	El Paso Electric Company
FERC	Federal Energy Regulatory Commission
IOU	Investor-Owned Electric Utilities
kWh	Kilowatt-hour
MW	Megawatt
MWh	Megawatt-hour
NARUC	National Association of Regulatory Utility Commissioners
NCP	Non-Coincident Peak
OPUC	Office of Public Utility Counsel
O&M	Operations and Maintenance
PUCT or Commission	Public Utility Commission of Texas
RFI	Request for Information
SOAH	State Office of Administrative Hearings
SPS	Southwestern Public Service Company

SWEPCO	Southwestern Electric Power Company
UTEP	University of Texas at El Paso

I. WITNESS IDENTIFICATION AND SCOPE OF TESTIMONY

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Evan D. Evans. My business address is 17450 Valley Lake Drive, Canyon, Texas 79015.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am a principal and a consultant with Integrity Power Consulting, LLC.

Q. ARE YOU THE SAME EVAN D. EVANS WHO FILED DIRECT TESTIMONY IN THIS PROCEEDING?

A. Yes, I am.

Q. ON WHOSE BEHALF ARE YOU PRESENTING TESTIMONY IN THIS PROCEEDING?

A. I am presenting testimony on behalf of the Office of Public Utility Counsel ("OPUC").

II. PURPOSE AND SCOPE OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR CROSS-REBUTTAL TESTIMONY IN THIS PROCEEDING?

A. The purpose of this cross-rebuttal testimony is to address cost allocation or rate design recommendations by witnesses for other intervening parties and the PUCT staff that differ from recommendations contained in my pre-filed direct testimony. Specifically, I will respond to the following witnesses and issues:

- Mr. Jeffry Pollock on behalf of Freeport-McMoRan, Inc. and his testimony concerning:

- the use of the single coincident peak ("1CP") to calculate the load-factor weighting in the Four Coincident Peak – Average and Excess Demand ("4CP-A&E") allocator for production and transmission demand costs;[1]
- the actual (i.e., unadjusted) system peak demands should be used to calculate the load factor;[2]
- the allocation of production and transmission load dispatching expenses;[3]
- his proposal that gradualism in the revenue distribution should only be applied to the Off-Peak Water Heating rate class;[4] and
- EPE's Loss Study and his proposal that the energy loss factors for the substation and transmission levels should be set at 90% of their respective demand loss factors.[5]

• Mr. Kevin C. Higgins on behalf of Texas Industrial Energy Consumers and his testimony concerning:

- the load factor used for weighting average demand in the 4CP-A&E allocator calculation should be based on single highest actual firm 1CP for EPE's system;[6]
- actual (i.e., unadjusted) system firm loads should be used in calculating system load factor;[7]
- the allocation of Generation System Control and Load Dispatching (FERC Account 556) on the 4CP-A&E allocation method;[8]

[1] Direct Testimony and Exhibits of Jeffry Pollock at 2:14 – 20 and 9:15 – 12:8.

[2] *Id.* at 12: 6 – 8.

[3] *Id.* at 3:11 – 24 and 22:3 – 25:8.

[4] *Id.* at 5:8 – 10.

[5] *Id.* at 3:6 – 10 and 14:3 – 21:8.

[6] Direct Testimony of Kevin C. Higgins at 4:23 – 26 and 19:1 – 21:15.

[7] *Id.* at 21:16 – 22:11.

[8] *Id.* at 5:1 – 3 and 24:1 – 13.

- the allocation of Transmission Load Dispatching (FERC Account 561) on the 4CP allocation method;[9] and
- Customers served at 115 kV should not be allocated costs associated with EPE's 69 kV transmission system.[10]

- Ms. Kit Pevoto on behalf of University of Texas at El Paso ("UTEP") and her testimony concerning the system load factor used in determining the 4CP-A&E demand allocators and the use of adjusted Coincident Peak ("CP") data for determining the system load factor;[11]
- Mr. James W. Daniel on behalf of the Rate 41 Group and his testimony concerning revenue increase distribution and a 20% discount for Rate 41 customers;[12] and
- Mr. Adrian Narvaez of the Rate Regulation Division of the PUCT Staff ("Staff") and his testimony concerning the use of the total annual system peak load factor based on the single CP to derive the 4CP-A&E class allocation factor:[13]

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS IN THE AREAS LISTED ABOVE.

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[9] *Id.* at 5:9 – 11 and 24:14 – 25:12.

[10] *Id.* at 7:12 – 14 and 25:13 – 27:2.

[11] Direct Testimony of Kit Pevoto at 9:3 – 9 and 10:4 – 12:15.

[12] Direct Testimony and Exhibits of James W. Daniel at 7:1 – 7 and 10:9 – 16:3.

[13] Direct Testimony of Adrian Narvaez at 5:16 – 17 and 9:7 – 12:5.

A. In this testimony, I recommend:

- Approval of EPE's proposal to use 4CP demands to calculate the load factor weighting in the calculation of the 4CP-A&E allocator;
- Approval of EPE's proposal to use energy and coincident peak demands that have been adjusted for year-end customers and weather normalization for the calculation of the load factor weighting in the calculation of the 4CP-A&E allocator;
- Approval of EPE's proposal to allocate FERC Account 556 - System Control and Load Dispatching Expense and FERC Account 561 – Load Dispatching based on the average of 12 coincident peak ("12CP") demands;
- Investment in EPE's 69 kV transmission lines and associated costs should be allocated to all customer classes, including those customer classes served at 115 kV;
- The base revenue increase distribution among customer classes should reflect moderation, and no firm service rate class should be increased by more than 150% of the Texas retail average increase percentage, and no firm service rate class should be increased by less than 50% of the Texas retail average percentage increase; and
- EPE's current loss factors, which were approved by the Commission in Docket No. 50058, are reasonable and should not be adjusted.

Q. IF YOU DO NOT ADDRESS AN ISSUE OR TAKE A POSITION ON ANY ISSUE IN YOUR CROSS-REBUTTAL TESTIMONY, SHOULD THAT BE INTERPRETED AS SUPPORTING THE POSITION TAKEN BY OTHER PARTIES ON THAT ISSUE?

A. No.

III. LOAD FACTOR TO USE IN 4CP-A&E CALCULATION

Q. PLEASE EXPLAIN THE ISSUE CONCERNING THE LOAD FACTOR TO BE USED IN THE CALCULATION OF EPE'S 4CP-A&E ALLOCATOR.

A. EPE proposed to calculate its 4CP-A&E allocator using its annual system load factor calculated based on its monthly system coincident peak demands for its four peak months of June through September, also known as 4CP, which is consistent with the peak demands used in the 4CP-A&E. Witnesses for some of the industrial intervenors, UTEP and Staff recommend using an annual system load factor calculated based on the single annual system coincident peak, also known as 1CP, which is not consistent with the peak demands used in the 4CP-A&E.

In the calculation of the 4CP-A&E allocator, there are two primary component parts, the average component and the excess component. To calculate the average component for each class, the class's loss-adjusted annual kWh is divided by the number of hours in the year, which equates to the class's annual average demand. Then the average demand is multiplied by the annual system load factor to derive the average component for each class. The excess component for each customer class is developed by subtracting the class's average demand from the class's contribution to EPE's system monthly coincident peak demands for the four summer months of June through September to calculate the excess demands for each class. However, no class is permitted to have a negative excess demand. Therefore, the excess demand is set to zero for customer classes that operate off-peak. Each class's excess demand is multiplied by one minus the annual system load factor to calculate the excess component for each class. The A&E-4CP demand allocation factor for each class equals the sum of each class's average component and its excess component.

Q. PLEASE SUMMARIZE THE REASONS THAT EACH WITNESS PROVIDED TO SUPPORT THE USE OF A 1CP LOAD FACTOR IN THE CALCULATION OF THE 4CP-A&E ALLOCATOR.

A. The reasons provided by Mr. Pollock in his direct testimony for using the 1CP load factor were:

- the Commission's precedent in past rate cases for other non-ERCOT investor-owned utilities ("IOUs") for using an annual 1CP to calculate the load factor for the 4CP-A&E allocation method;[14]
- the Electric Utility Cost Allocation Manual ("CAM") published by the National Association of Regulatory Utility Commissioners ("NARUC") states that in applying the AED method annual system load factor should be derived from the utility's annual 1CP system peak;[15]
- the 1CP load factor is consistent with the fact that EPE's planning reserve margin is based on EPE's available capacity and load at its annual system peak.[16]

The reasons provided by Mr. Higgins in his direct testimony for using the 1CP load factor were:

- it does not adhere to the normal convention of using a 1CP annual system coincident peak;[17]

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[14] Direct Testimony and Exhibits of Jeffry Pollock at 9:2 – 11:8.

[15] *Id.* at 11:9 – 15.

[16] *Id.* at 11:16 – 12:2.

[17] Direct Testimony of Kevin C. Higgins at 19:6 – 18.

- use of 4CP to calculate annual system load factor is not consistent with the discussion of the Average and Excess Demand method in the NARUC CAM;[18]
- it is not consistent with Commission precedent in two recent cases for Southwestern Public Service Company ("SPS") and Southwestern Electric Power Company ("SWEPCO");[19] and
- there is only one system load factor during the year that is based on the single annual system peak for the year.[20]

The reasons provided by Ms. Pevoto in her direct testimony for using the 1CP load factor were:

- the 1CP system load factor reflects more of the manner in which a utility plans and builds its generation facilities;[21] and
- the use of a 4CP system load factor is not consistent with the Commission's previous decisions on this issue.[22]

The reasons provided by Mr. Narvaez in his direct testimony for using the 1CP load factor were:

- the Commission approved the use of the single total annual system peak load factor for deriving the 4CP-A&E in Docket Nos. 43695 and 46449;[23]
- EPE's system planning is based on total system peak and the load factor used to derive the 4CP-A&E allocation factor should be calculated using EPE's total annual system peak;[24]and

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18 *Id.* at 20:3 – 8.

19 *Id.* at 20:10 – 15.

20 *Id.* at 20:18 – 25.

21 Direct Testimony of Kit Pevoto at 10:12 – 14 and 10:17 – 11:4.

22 *Id.* at 10:15 – 16 and 11:5 – 17.

23 Direct Testimony of Adrian Narvaez at 9:13 – 10:2.

24 *Id.* at 10:3 – 11:4.

- the use of 4CP load factor distorts actual total system peak demand and therefore does not reflect the extent to which each class contributes to EPE's total annual system peak demand.[25]

a. Prior Commission Precedent for Other Non-ERCOT IOUs

Q. DO YOU BELIEVE THE COMMISSION'S DECISIONS IN THE SPS AND SWEPCO RATE CASES ON THIS ISSUE ESTABLISH PRECEDENCE ON THIS ISSUE FOR EPE?

A. No, I do not. The Commission's decisions in the SPS and SWEPCO rate cases were based on their review of the characteristics of those utilities, the circumstances that existed when each of those orders were issued and the testimony and evidence presented to the Commission in each of those cases.

Q. ARE THE CHARACTERISTICS OF EPE'S SYSTEM SIGNIFICANTLY DIFFERENT FROM THOSE OF SPS AND SWEPCO?

A. Yes. The mix of retail customers, the annual system load factors, and the relationship of the 1CP demand to 4CP system demands for EPE is significantly different from those of SPS and SWEPCO. Those differences exist even though all four of the non-ERCOT IOUs are summer peaking utilities and use the 4CP-A&E allocation method to allocate production plant.

Residential customers account for a significantly greater percentage of EPE's annual MWh sales than large commercial and industrial customers. That relationship is not true for SPS and SWEPCO. Attachment EDE-1CR provides a comparison of EPE's sales by

[25] *Id.* at 11:4 – 10.

retail customer groups to those of the other three non-ERCOT IOUs. That table reveals that sales to large commercial and industrial customers only accounted for 12.1% of EPE's 2020 MWh sales to retail customers. In contrast, sales to large commercial and industrial customers accounted for 30.1% of SWEPCO's 2020 MWh sales to retail customers and 55.7% of SPS's 2020 MWh sales to retail customers.

In addition, Attachment EDE-2CR provides a comparison of the relationships between 4CP demands and 1CP demands for EPE and the other three non-ERCOT IOUs for the five years of 2016 through 2020. It also provides a comparison of the calculated annual load factors based on 4CP demands and 1CP demands between the utilities.

A review of Attachment EDE-2CR reveals some significant differences between EPE and the other utilities. One significant difference is that EPE's annual load factor, whether calculated using 4CP demands or 1 CP demands, is between 4.2% to 18.8% lower than the other utilities every year. Another significant difference is that although the 4CP demands are almost always between 94% to approximately 97% for all four of the utilities, that ratio drops to below 93% for EPE in two of the five years. This is the result of dramatically higher 1CP demands for EPE in those two years, 2017 and 2020, and reflects a condition known as "needle peaking."

Q. HAVE YOU COMPARED EPE'S SYSTEM PEAK LOADS TO THOSE OF ANY OF THE OTHER THREE NON-ERCOT UTILITIES?

A. Yes. I have compared EPE's system peak load hours to those of SPS. In response to OPUC's First Request for Information ("OPUC RFI"), No. 1-22, EPE supplied its hourly system generation loads for 2020. Also, in response to discovery in SPS's current rate case, Docket No. 51802, SPS supplied their hourly generation loads for 2020. Attachment EDE-3CR provides a table identifying the hours of native generation loads on EPE's system and SPS's system within 5% of their respective system peaks in 2020.

A review of the data provided in Attachment EDE-3CR reveals that during 2020, EPE only had three hours, besides the system peak hour, within 3% of the annual system peak. The three highest hourly loads occurred on the same date, July 13, 2020, and the fourth highest occurred on the next day, July 14. In comparison, SPS had 10 hours, besides the system peak hour, within 3% of its annual system peak, or 3.33 times as many hours as EPE had within 3% of its annual peak.

Furthermore, SPS's lowest hourly load in 2020 was 49.50% of its peak hourly load. In contrast, EPE's lowest hourly load in 2020 was only 25.5% of its peak hourly load, and its average hourly load was only 45.7% its peak hourly load. Therefore, EPE's average hourly load was a smaller percentage of its peak hourly load in 2020 than SPS's lowest hourly load was to SPS's peak in 2020.

The system load characteristics for EPE are drastically different from those for SPS. Therefore, the circumstances and operating characteristics considered in Docket No. 43695, SPS's 2014 rate case, are drastically different from the circumstances and operating characteristics for EPE in this rate case. In addition, as I discussed previously, Attachment EDE-2CR also shows that EPE's load characteristics are significantly different from SWEPCO and Entergy Texas's load characteristics. Consequently, the Commission's decisions in Docket Nos. 43695 and 46449 should not establish precedent for EPE on the matter of the appropriate calculation of the 4CP-A&E.

Q. DID ANY OF THE WITNESSES WHO POINTED TO COMMISSION DECISIONS IN THE SPS AND SWEPCO DOCKETS COMPARE EPE'S SYSTEM AND OPERATION TO THOSE OF SPS OR SWEPCO IN SUPPORT OF THEIR RECOMMENDATIONS?

A. The only witness to even make a cursory comparison of EPE's system and operations to those of SPS and SWEPCO was Ms. Pevoto. Ms. Pevoto made the following general, but incorrect statement:

> "Both EPE and SPS are located in northwest Texas and their service areas are close to each other. In addition, they are both summer peaking utilities that must build their generation and transmission facilities to meet the maximum peak demand usage that occurs in one of the summer months. Therefore, EPE should follow the PUC's Final Order for SPS in Docket No. 43695, and utilize the 1CP system load factor in its proposed 4CP-A&E allocators calculation."[26]

However, EPE is located in far west Texas, not northwest Texas. The predominant portion of SPS's Texas retail loads is located in the Texas Panhandle and the South Plains region of Texas. The climate in El Paso is vastly different from the climate in Amarillo and the Texas Panhandle, and the operations and system load characteristics are also vastly different, as shown in Attachments EDE-2CR and EDE-3CR. Therefore, Ms. Pevoto's statement is erroneous and does not support her contention that EPE and SPS are comparable and that, "EPE should follow the PUC's Final Order for SPS in Docket No. 43695 and utilize the 1CP system load factor in its proposed 4CP-A&E allocators calculation."[27]

[26] Direct Testimony of Kit Pevoto at 11:12 – 17.

[27] *Ibid.*

b. Discussion of Load Factor in the NARUC Cost Allocation Manual

Q. DOES THE NARUC COST ALLOCATION MANUAL REQUIRE THAT ANNUAL SYSTEM LOAD FACTOR TO BE USED IN THE 4CP-A&E ALLOCATION METHOD BE DERIVED FROM THE UTILITY'S ANNUAL 1CP SYSTEM PEAK?

A. No. The NARUC Cost Allocation Manual does not even identify or discuss the 4CP-A&E allocation method. The NARUC Cost Allocation Manual only discusses the Average and Excess Demand ("AED") allocation method, which is very different from the 4CP-A&E method that EPE and other electric utilities in Texas use. The AED method is based on each customer class's maximum class demand and the average annual demand for each customer class. The maximum class demands for classes are not coincident with the annual system peak demand for the utility. The maximum class demands for each customer class is a single demand that can occur during any hour and any month in the year.

The AED production demand allocation method is described on pages 49 - 52 of the NARUC Cost Allocation Manual, which is provided as Attachment EDE-4CR. In the description of the AED demand allocation method it states, "The method allocates production plant costs to rate classes using factors that combine the classes' average demands and non-coincident peak ("NCP") demands."[28]

Furthermore, the NARUC Cost Allocation Manual recommends that coincident peak demands should not be used to calculate the excess demand component of the AED method. It states:

> "If your objective is -- as it should be using this method --to reflect the impact of average demand on production plant costs, then it is a mistake to

[28] NARUC Electric Utility Cost Allocation Manual at page 49.

> allocate the excess demand with a coincident peak allocation factor because it produces allocation factors that are identical to those derived using a CP method. Rather, use the NCP to allocate the excess demands."[29]

In contrast, the 4CP-A&E relies on the contribution of every customer class to the four summer monthly system coincident peak demands and does not utilize non-coincident peak demands at all. Consequently, the description of the AED demand allocation method in the NARUC Cost Allocation Manual does not apply to the 4CP-A&E allocation method used by EPE and other Texas utilities.

Q. DOES THE NARUC COST ALLOCATION MANUAL ESTABLISH MANDATES ON COST ALLOCATION METHODS?

A. No. The writing style and tenor is informative and advisory. It is not written in a directive style that is intended to convey mandates. As a matter of fact, the authors of the Cost Allocation Manual discussed their objectives in the Preface. One of the stated objectives was, "The writing style should be non-judgmental; not advocating any one particular method but trying to include all currently used methods with pros and cons."[30] It would, therefore, be incorrect to say that the NARUC Cost Allocation Manual advocates for any particular cost allocation method.

Q. DOES THE DEFINITION OF LOAD FACTOR IN THE COMMISSION'S RULES ESTABLISH THAT ONLY THE SINGLE ANNUAL SYSTEM PEAK CAN BE USED TO CALCULATE SYSTEM LOAD FACTOR?

[29] *Id.* at 50.

[30] *Id.* at page ii.

A. No. The Commission's definition for "load factor" is found in 16 TAC § 25.5 (64) and states:

> **Load factor** -- The ratio of average load to peak load during a specific period of time, expressed as a percent. The load factor indicates to what degree energy has been consumed compared to maximum demand or utilization of units relative to total system capability.[31]

The definition says it is the "ratio of average load to peak load." It does not define peak load as a single peak hour or as the single system coincident peak load. This definition only requires the average load and the peak load be "during a specific period of time." This definition is not prescriptive as to the method for calculating load factor. Consequently, the calculation of load factor using 4CP demands, which is the average system coincident peak load for the four summer months, is permissible under the Commission's rules.

c. 1CP Loads and EPE's Generation System Planning

Q. ARE ANNUAL SYSTEM PEAK DEMANDS A MAJOR CONSIDERATION IN THE GENERATION SYSTEM PLANNING FOR EPE AND OTHER FULLY-INTEGRATED ELECTRIC UTILITIES?

A. I was regularly involved with system resource planning during my 34 years of employment with investor-owned electric utilities. Based upon my knowledge and experience in the industry, I know that EPE and other utilities plan their generation resources to ensure they have sufficient capacity to serve their forecasted peak demand each year plus their planning reserve margin requirement. However, Electric utility system planners consider significantly more than a single hourly peak load for purposes of system planning. Utilities

[31] 16 TAC § 25.5 (64).

also consider their loads throughout the peak period and variations in their loads throughout the year in their generation system resource planning. Utilities plan and build their generation systems and acquire generation resources in order to reliably serve their customers during all hours and at the lowest reasonable cost. Ensuring a utility has sufficient resources to handle the greatest demand that is expected to be placed on their systems is only one of the many factors that are considered.

Furthermore, EPE and other utilities use their forecasted peak demands and not their actual demands for the current year or historical test-year for system planning. The forecasted peak demands are developed based upon expected weather conditions, expected additions or reductions in customer loads, forecasted economic factors and other factors that are expected to be present in the planning period.

It would be extremely myopic and imprudent for a utility to develop its generation system resource plan with a singular focus of only ensuring they had adequate generation resources to meet their forecasted peak demand plus planning reserve requirements. Furthermore, it would not be appropriate for a utility to allow its actual, historical peak demand to drive its generation system resource planning for the future. This would be reactionary planning that fails to consider potential future conditions. Consequently, annual system peak demands are an important consideration in utilities' generation resource system planning, but so also are several other factors, including those I have just identified.

d. Only One System Load Factor During the Year

Q. MR. HIGGINS STATES THAT THERE IS ONLY ONE SYSTEM LOAD FACTOR DURING THE YEAR, NOT MULTIPLE LOAD FACTORS DEPENDING ON HOW MANY COINCIDENT PEAKS ARE USED TO CALCULATE EXCESS DEMAND. DO YOU AGREE?

A. No, I do not agree. Mr. Higgins did not provide any cite to any decisions by this Commission or any authoritative documents to support his statement. In contrast, this Commission has approved 4CP-A&E calculations that were developed using 4CP load factors in prior cases, including Docket Nos. 39896[32] and 40443.[33] Furthermore, it is inconsistent to use customer class contributions to the 4CP demands as the basis for calculating the excess demand component of the 4CP-A&E allocation factor, but to use a 1CP demand to calculate the annual load factor. If it is appropriate to use 4CP demands to represent the annual system peak demand in the allocator, it is also appropriate and consistent to use 4CP demands for the system peak demand in the calculation of the annual load factor.

e. Other Arguments That Support Using 4CP Demands to Calculate Load Factors in the 4CP-A&E

Q. ARE THERE OTHER ARGUMENTS THAT SUPPORT USING 4CP DEMANDS TO CALCULATE LOAD FACTORS IN THE DEVELOPMENT OF THE 4CP-A&E ALLOCATION FACTORS?

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[32] Order on Rehearing (Docket No. 39896), Findings of Fact Nos. 183 and 184.

[33] Order on Rehearing (Docket No. 40443), Findings of Fact Nos. 282 – 285.

A. Yes. The use of a single, historical annual CP demand can vary significantly between years, and using it as the basis for calculating the load factor will tend to produce an unstable allocator. This instability is increased if the actual historical annual CP is used instead of the adjusted annual CP demand. In addition, with regards to the calculation of energy loss factors, Mr. Pollock expressed concern that the use of power flows for only eight hours is not sufficient to accurately calculate EPE's energy loss factors.[34] Therefore, based on Mr. Pollock's concern about an insufficient number of data points in the loss factor calculations, Mr. Pollock and the Commission should be very concerned about using only one hourly load to calculate the load factor for the 4CP-A&E allocator.

In addition, the use of a 1CP to calculate the load factor for the calculation of the average weighting for the 4CP-A&E allocator is inconsistent with the 4CP demands used to represent the system peak in the allocator. This inconsistency distorts the results of the 4CP-A&E method. That distortion is discussed later in this testimony.

Finally, I agree with Mr. Narvaez that "cost allocation should reflect the cost drivers that cause the utility to incur a particular cost."[35] However, I also believe that stability and predictability of the cost allocation method should not be ignored in the pursuit of an approach that some parties claim more accurately reflects cost causation.

Q. PLEASE EXPLAIN YOUR CONCERN THAT USING A SINGLE ANNUAL CP DEMAND TO CALCULATE THE LOAD FACTOR WILL TEND TO PRODUCE AN UNSTABLE ALLOCATOR.

[34] Direct Testimony and Exhibits of Jeffry Pollock at 19:6 – 13.

[35] Direct Testimony of Adrian Narvaez at 10:24 – 25.

A. A single coincident peak demand can vary significantly between years due to short-term weather anomalies during the summer. A short-term, intense heat wave that produces abnormally hot temperatures for few days can cause an unexpectedly high peak load that occurs in one month, which would lead to a lower calculated 1CP load factor. EPE's system is at particular risk of this occurring, because their loads consist of predominantly residential and small commercial loads that are more weather sensitive. Consequently, if the above-normal temperatures do not persist throughout the summer, it will cause the calculated load factor for that year to be lower than expected.

The instability of using a 1CP load factor for EPE is shown in Attachment EDE-2CR. A review of the table reveals that 1CP load factors vary significantly more between years than the 4CP load factors. The use of multiple CP demands will naturally reduce the variations in the load factor used to calculate the 4CP-A&E, which is reflected in Attachment EDE-2CR. Reduced variations in the load factor will cause the calculated 4CP-A&E allocator to be a more stable allocator between rate cases. Because the 4CP-A&E is used by EPE to allocate production demand costs, which comprise a significant portion of EPE's cost of service, then reducing unnecessary variations will lead to greater rate stability.

Q. EARLIER YOU MENTIONED "NEEDLE PEAKS." WHAT IMPACT DO NEEDLE PEAKS HAVE ON THE CALCULATION OF EPE'S ANNUAL SYSTEM LOAD FACTOR AND THE CALCULATION OF THE 4CP-A&E ALLOCATOR?

A. Needle peaks will cause the annual system load factor calculated using a 1CP to be unduly low. This will cause more of the excess, or peak, component to be exaggerated and will cause an excessive amount of costs to be allocated to lower load factor customer classes that peak during the summer. In addition, it will unreasonably reduce the allocation of costs to higher load factor customer classes or customer classes that operate off-peak.

Q. PLEASE DISCUSS THE IMPORTANCE OF STABILITY AND PREDICTABILITY IN COST ALLOCATION.

A. Stability and predictability in cost allocation is important because it will produce stable and predictable rates for customers. Customers' expectations of the level of electric rates and the stability of those rates will impact their equipment purchasing decisions. These equipment purchases are often expensive, and because the equipment typically have long operating lives, these purchase decisions will impact customers for a long time. Therefore, although I agree that it is important for cost allocation to reasonably reflect cost causation factors, the pursuit of that goal should not result in sacrificing rate stability.

Rate stability and predictability is one of the ten attributes of a sound rate structure identified in the often-referenced Principles of Public Utility Rates.[36]

Q. PLEASE DISCUSS YOUR CONCERN THAT USING A 1CP DEMAND TO CALCULATE THE LOAD FACTOR FOR THE AVERAGE WEIGHTING IN THE 4CP-A&E IS INCONSISTENT WITH THE 4CP DEMANDS USED TO REPRESENT THE SYSTEM PEAK IN THE ALLOCATOR.

Due to the fact the 4CP-A&E allocator is developed based on average demands and on 4CP demands, it is inconsistent and inappropriate to calculate the system load factor based on

[36] Principles of Public Utility Rates 2nd. Edition by James C. Bonbright, Albert L. Danielsen, David R. Kamerschen (March 1988) at 382 – 388.

1CP demands. The use of 4CP demands to represent the peak period and to calculate the excess component of the 4CP-A&E allocator has been approved by the Commission in multiple rate cases.[37] The use of a 1CP to calculate the load factor for the average weighting component of the 4CP-A&E allocator distorts the results. This approach inappropriately suppresses the average and the excess components for high load factor customer classes and customer classes that operate off-peak, such as industrial and lighting classes. At the same time, this approach also inappropriately inflates the average and the excess components for lower load factor customer classes that use energy during peak periods, such as the Residential Service and Small General Service classes. As a matter of fact, the use of the 1CP for load factor weighting actually causes some low load factor customer classes that operate on-peak, including Residential Service, to be allocated more costs than a straight 4CP demand allocation. Attachment EDE-5CR compares the 4CP-A&E allocator calculated using the 4CP for calculating load factor weighting to the 4CP-A&E using a 1CP for calculating load factor weighting and a straight 4CP demand allocation. Attachment EDE-5CR clearly shows the allocation of costs would be inappropriately shifted to Residential Service and other lower load factor customer classes that operate on-peak.

[37] Order on Rehearing (Docket No. 39896), Findings of Fact Nos. 183 and 184. Order on Rehearing (Docket No. 40443), Findings of Fact Nos. 282 – 285.

IV. USE OF ADJUSTED ENERGY AND SYSTEM PEAK DEMANDS TO CALCULATE LOAD FACTOR FOR 4CP-A&E ALLOCATOR

Q. PLEASE EXPLAIN THE ISSUE CONCERNING THE LOAD FACTOR TO BE USED IN THE CALCULATION OF EPE'S 4CP-A&E ALLOCATOR.

A. Mr. Pollock,[38] Mr. Higgins[39] and Ms. Pevoto[40] all recommend that actual energy and peak demand, rather than adjusted energy and peak demand, be used to calculate the load factor used to develop the 4CP-A&E allocator for EPE. In contrast, EPE used energy and peak demands that have been adjusted to annualize the year-end number of customers and to adjust for abnormal weather in the calculation of the load factor it used.

Q. WHAT REASONS DID THE WITNESSES PROVIDE FOR THEIR RECOMMENDATIONS TO USE ACTUAL ENERGY AND PEAK DEMAND?

A. Mr. Pollock's stated justification was, "The Commission has previously determined that the load-factor weighting should be based on the actual (unadjusted) annual system load factor ("ASLF").[41] Mr. Higgins's said, "Using the actual (i.e., unadjusted) firm loads for this purpose best represents system load factor during the test period."[42] Ms. Pevoto asserted that the Commission had previously decided that the use of unadjusted (actual) energy and demand data to calculate the system load factor was appropriate and the actual energy and peak demand data provides more accurate representation of how fully the

[38] Direct Testimony and Exhibits of Jeffry Pollock at 12:6 – 8.

[39] Direct Testimony of Kevin C. Higgins at 21:16 – 20.

[40] Direct Testimony of Kit Pevoto at 12:7 – 15.

[41] Direct Testimony and Exhibits of Jeffry Pollock at 7:19 – 20.

[42] Direct Testimony of Kevin C. Higgins at 21:18 – 20.

system is being utilized than the peak demand adjusted for weather and customer normalization.[43]

Q. HAS THE COMMISSION PREVIOUSLY DETERMINED THAT THE LOAD FACTOR WEIGHTING FOR EPE SHOULD BE BASED ON ACTUAL ENERGY AND PEAK DEMANDS?

A. No, the Commission has not made that determination for EPE. Ms. Pevoto cited Proposal For Decision, page 266, Docket No. 40443, *Southwestern Electric Power Company for Authority to Change Rates* as the basis for her claim that the Commission had previously "decided that the use of unadjusted (actual) energy and demand data to calculate the system load factor was appropriate." However, the Order on Rehearing in Docket No. 40443 does not contain any discussion or Findings of Fact consistent with her claim.[44]

Q. DID MR. HIGGINS OR MS. PEVOTO PROVIDE ANY SUPPORT FOR THEIR CLAIM THAT USING ACTUAL PEAK DEMAND AND ENERGY BETTER REPRESENTS SYSTEM USAGE AND LOAD FACTOR?

A. No, they do not provide any support. Furthermore, use of actual peak demand and energy for calculating the load factor would not be consistent with the adjusted customer class demands and energy used in the development of the 4CP-A&E. Use of actual peak demand and energy would also not be consistent with the year-end rate base and test-year adjusted expenses used to calculate the cost of service being allocated among customer classes based on the 4CP-A&E allocation method.

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[43] Direct Testimony of Kit Pevoto at 11:18 – 12:15.

[44] Order on Rehearing in Docket No. 40443, March 6, 2014.

Q. ARE THERE OTHER ISSUES WITH USING ACTUAL DEMAND AND ENERGY TO CALCULATE THE LOAD FACTOR FOR THE 4CP-A&E?

A. Yes. Actual demand and energy are subject to greater variability that result from abnormal weather that causes demands and energy to be abnormally high or low. In addition, the sales forecasts used by system planners contain forecasts based upon expected weather conditions and expected or known load changes.

V. ALLOCATION OF DISPATCHING EXPENSES

Q. PLEASE DESCRIBE THE ISSUE RELATED TO THE ALLOCATION OF DISPATCHING EXPENSES.

A. EPE proposed allocating of FERC Account 556 - System Control and Load Dispatching Expense and FERC Account 561 – Load Dispatching based on the average of 12 coincident peak ("12CP") demands.[45] Mr. Pollock[46] and Mr. Higgins[47] recommend Account No. 556 expense be allocated among classes using the AED-4CP method and Account No. 561 expense be allocated among classes using the 4CP method.

Q. WHY DID EPE PROPOSE ALLOCATING ACCOUNTS 556 AND 561 BASED ON 12CP?

A. Mr. Adrian Hernandez filed direct testimony for EPE addressing EPE's jurisdictional and class cost allocation studies. Mr. Hernandez stated, "Load dispatching costs are incurred year-round; therefore, these costs are allocated using a 12CP allocator."

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[45] Direct Testimony of Adrian Hernandez at 13:11 - 12 and 14:21 – 26.

[46] Direct Testimony and Exhibits of Jeffry Pollock at 3:11 – 24 and 22:3 – 25:8.

[47] Direct Testimony of Kevin C. Higgins at 5:1 – 11 and 24:13 – 25:2.

Q. MESSRS. POLLOCK AND HIGGINS ARGUE THAT THE LOAD DISPATCHING COSTS IN THOSE FERC ACCOUNTS SHOULD BE ALLOCATED IN THE SAME MANNER AS THE UNDERLYING ASSETS. DO YOU AGREE?[48]

A. No. Load dispatching reflects EPE's operation of its production and, transmission systems. Load dispatching is a daily operation that occurs throughout the year every hour of every day. These activities and the associated expenses are incurred without respect to the loading on EPE's system. Load dispatching activities and the associated expenses are incurred when loads are the lowest similar to when the system peaks. Based on the daily and year-round nature of dispatching, the 12CP demands is an appropriate method for allocating these costs.

Q. HAS THE COMMISSION CONSIDERED SIMILAR ARGUMENTS TO THOSE RAISED BY MESSRS. POLLOCK AND HIGGINS IN OTHER RATE CASES?

A. Yes. In Docket No. 43695, SPS's 2014 rate case, the Commission considered similar arguments raised by Mr. Pollock and Ms. Pevoto to support the allocation of SPS's dispatching expenses and rejected those arguments. The following Findings of Fact from the Order on Rehearing in Docket No. 43695 reflect the Commission's decision on these arguments:

> 285. Load dispatching reflects SPS's operation of its production, transmission, and distribution systems.
> 286. Load dispatching is a daily operation that occurs throughout the year every hour of every day, and must meet reliability requirements during peak and low-demand times.
> 287. Peak demand usage is included in each class's average demand over the course of a year.

[48] Direct Testimony and Exhibits of Jeffry Pollock at 29:13 – 20 and Direct Testimony of Kevin C. Higgins at 24:6 – 22.

289. The 12CP demand allocator balances the requirement to dispatch load to meet average usage and the requirement to dispatch load to meet maximum annual peak demand.

290. SPS reasonably allocated system control and dispatching costs among customer classes based on 12CP demand in this case and, based on the daily nature of dispatching, average usage throughout the year is an appropriate method for allocation.

291. SPS properly allocated transmission-related load dispatch costs recorded in FERC Account 561 using an average demand allocator.

292. It is reasonable for SPS to allocate distribution-related load dispatch costs recorded in FERC Account 581 using an average demand allocator.

Although Mr. Pollock argues that Account No. 556 expense should be allocated using the AED-4CP method and Account No. 561 expense should be allocate using the 4CP method to comport with the practices of other Texas utilities, it would not comport with the Commission's decision on this contested issue in Docket No. 43695.

VI. ALLOCATION OF COSTS OF EPE'S 69KV TRANSMISSION SYSTEM

Q. PLEASE SUMMARIZE THE ISSUE RAISED BY TIEC WITNESS MR. HIGGINS CONCERNING THE ALLOCATION OF COSTS ASSOCIATED WITH EPE'S 69KV TRANSMISSION SYSTEM.

A. Mr. Higgins argues that it is not appropriate to allocate 69 kV line costs to customer classes served at 115 kV because, "Customers who take service directly at 115 kV voltage generally do not utilize the 69 kV system."[49]

Q. IS MR. HIGGINS CORRECT THAT 115 KV CUSTOMERS DO NOT USE EPE'S 69 KV SYSTEM?

[49] Direct Testimony of Kevin C. Higgins at 26:6 – 10.

A. Mr. Higgins did not supply any valid evidence in support of his assertion that 115 kV customers do not use EPE's system. However, in response to TIEC's RFI No. 8-6, EPE stated:

> The 115 kV and 69 kV transmission systems are part of an interconnected system. Power flowing to customers taking service at transmission voltages (115 kV or 69 kV) can easily flow from the 69 kV system to the 115 kV system, or conversely, from the 115 kV system to the 69 kV system, depending on the system configuration at any point in time. Therefore, the power flowing to a customer taking transmission service at 115 kV could be utilizing a path that includes the 69 kV system, along with the 115 kV system.[50]

EPE's response to TIEC RFI. No. 8-6 is provided as Attachment EDE-6CR.

Q. WHAT IS YOUR POSITION ON THIS ISSUE?

A. I recommend that Mr. Higgins' recommendation be rejected. Investment in EPE's 69 kV transmission lines and associated costs should be allocated to all customer classes, including those customer classes served at 115 kV.

Mr. Higgins's foundational assumption that customer classes served at 115 kV do not use EPE's 69 kV transmission system was directly refuted by EPE's response to TIEC RFI No. 8-6. In addition, Mr. Higgins acknowledged, "Since EPE does not separate its transmission costs into sub-functions based on voltage, I was not able to precisely reallocate the 69 kV costs in a manner excluding 115 kV rate schedules."[51] Therefore, Mr. Higgins resorted to estimating the cost of the 69 kV transmission system and adjusted his proposed revenue increase distribution by customer class.[52]

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[50] EPE's Response to TIEC RFI No. 8-6.

[51] Direct Testimony of Kevin C. Higgins at 26:13 – 15.

[52] *Ibid.* at 26:11 – 21.

VII. DISTRIBUTION OF BASE RATE INCREASE AMONG CUSTOMER CLASSES

Q. PLEASE SUMMARIZE THE RECOMMENDATIONS OF OTHER WITNESSES ON THE DISTRIBUTION OF BASE RATE INCREASE AMONG CUSTOMER CLASSES.

A. Mr. Pollock recommended that gradualism only be applied to the Off-Peak Water Heating class, for which he recommends the base rate increase be limited to 43%. However, he recommended that all other customer classes be moved to their full, allocated cost of service.[53]

Mr. Higgins recommended that all cross-subsidies among customer classes be eliminated, and all customer classes be moved to their full, allocated cost of service.[54]

Mr. Daniel argues that the Rate 41 customers should receive a base rate decrease that includes a 20% discount below their allocated cost of service.[55]

Q. WHAT IS MR. POLLOCK'S BASIS FOR HIS RECOMMENDATION?

A. Mr. Pollock based his recommendation on the argument, "The Commission has had a long-standing policy of cost-based pricing"[56]and his assertion that the COVID-19 Pandemic does not reveal a shift in usage patterns that would affect the class cost-of-service study results.[57]

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[53] Direct Testimony and Exhibits of Jeffry Pollock at 34:19 – 35:7.

[54] Direct Testimony of Kevin C. Higgins at 29:3 – 12.

[55] Direct Testimony of James W. Daniel at 11:1 – 16.

[56] Direct Testimony and Exhibits of Jeffry Pollock at 34:7 – 8.

[57] *Id.* at 33:1 – 18.

Q. WHAT IS THE BASIS FOR MR. POLLOCK'S ASSERTION THAT THE COVID-19 PANDEMIC DID NOT RESULT IN A SHIFT IN USAGE PATTERNS THAT WOULD AFFECT THE CLASS COST-OF-SERVICE STUDY RESULTS?

A. Mr. Pollock provided Exhibit JP-8 to his prefiled testimony that compares energy sales and base revenues by customer class between EPE's last rate case and this rate case. Unsurprisingly, his comparison showed for 11 out of 17 customer classes, those customer classes whose kWh consumption increased, their base revenues also increased, and those customer classes whose kWh consumption decreased, their base revenues also decreased. However, for six of the 17 customer classes, or 35% of the customer classes, that relationship did not hold true. Those six customer classes were:

- Small General Service;
- Outdoor Recreational Lighting Service;
- General Service;
- Private Area Lighting Service;
- Electric Furnace Rate; and
- Cotton Gin Service.

As a result Mr. Pollock stated, "In summary, the shift in usage pattern cited by EPE during the test year will have no discernable impact on the CCOSS results. Accordingly, shifting usage patterns is not a reason to moderate the proposed base rate increases."[58]

Q. DOES MR. POLLOCK'S EXHIBIT PROVE THE SHIFT IN USAGE PATTERNS CITED BY EPE DURING THE TEST-YEAR HAD NO DISCERNABLE IMPACT ON THE CCOSS?

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[58] *Id.* at 34: 1 – 3.

A. No, it does not. It simply shows an imprecise relationship between kWh changes for customer classes and base revenue changes for those customer classes. As a matter of fact, it is surprising that the relationship was completely wrong for 35% of the customer classes, and that it was wrong for the large classes of Small General Service and General Service.

Furthermore, Mr. Pollock's exhibit does not provide sufficient information about comparative changes in kWh sales between customer classes, any analysis of changes in demands, or changes in various cost components sufficient to determine that shift in usage pattern cited by EPE during the test year will have no discernable impact on the CCOSS results.

Q. HAVE YOU ANALYZED THE CHANGES IN USAGE BY CUSTOMER CLASS FOR THE TEST-YEAR COMPARED TO PREVIOUS YEARS?

A. Yes. Attachment EDE-7CR provides a comparison in changes in usage for the test-year to the previous 10 years for each customer class. This attachment does reveal significant changes in consumption for Residential Service compared to the other customer classes. Attachment EDE-7CR indicates a significant change in usage among the customer classes and indicates that the allocation of costs between customer classes would also be significantly impacted.

Q. DO YOU AGREE WITH MR. HIGGINS THAT ALL CUSTOMER CLASSES SHOULD BE MOVED TO FULL COST OF SERVICE IN THIS RATE CASE?

A. No. The test-year, calendar year 2020, was an unusual year. The pandemic significantly impacted the loads and the usage characteristics of customer classes in diverse ways and impacted the allocation of costs among customer classes. It is unknown how the pandemic will impact the usage patterns during the period in which rates are in effect and how much permanently. The Commission has already found, in a previous EPE case no less, that the effects of the pandemic are still speculative and unknown with regards to the long-term.[59] Therefore, it would not be appropriate to assign large increases or decreases in this rate case in an attempt to move all customer classes to full cost-of-service based on the results of test-year that is universally recognized as being unusual.

Q. DO YOU AGREE WITH MR. DANIEL'S ARGUMENT THAT THE RATE 41 CLASS SHOULD BE ASSIGNED A 20% DISCOUNT FROM FULL COST OF SERVICE, WHICH WOULD RESULT IN A VERY LARGE BASE RATE DECREASE?

A. No. Mr. Daniel bases that argument on the following assertions:

1. "Since its inception over 70 years ago, Rate 41 was never intended to be based on the full cost of service. Instead, the public policy record indicates that Rate 41 was intended to provide school districts and local governments a rate discount in exchange for franchise agreements."[60]

2. "In 1995 the Texas Legislature passed SB 1524 which required EPE to include El Paso Community College ("EPCC") in the Rate 41 customer class. Since the Legislature determined EPCC should be included in Rate 41 and receive the rate discount, it is doubtful that the Legislative [sic] would have taken this action if it believed the rate discount was not warranted and should be eliminated or that the rate class should be dissolved."[61]

However, Mr. Daniels did not provide any evidence that supported his contention that the Rate 41 was never intended to be based on full cost of service and that Rate 41

[59] *Application of El Paso Electric Company to Amend its Certificate of Convenience and Necessity for an Additional Generating Unit at the Newman Generating Station in El Paso County and the City of El Paso*, Docket No. 50277, Proposal For Decision at 24 (Sep. 3,2020).

[60] Direct Testimony and Exhibits of James W. Daniel 11:9 – 12:2.

[61] *Id.* at 12: 3 – 7.

customers were given a rate discount in exchange for franchise agreements. There are also two problems with Mr. Daniel's assertion. First, utilities do not have franchise agreements with school districts. Second, it would be a violation of PURA 36.007(d) for Rate 41 customers to be provided a 20% discount and to permit EPE to recover the discount from other customer classes. PURA 36.007(d) states, "Notwithstanding any other provision of this title, the commission shall ensure that the electric utility's allocable costs of serving customers paying discounted rates under this section are not borne by the utility's other customers."[62]

In addition, SB 1524 from the 74th Regular Texas Legislative Session does not refer to discounts expressly to El Paso Community College. That legislation only stated, "Notwithstanding any other provision of this Act, where the commission, for electric service, has approved the establishment of a separate rate class for a university and where the commission has grouped public schools in a separate rate class, the commission shall include any community college in the rate class containing public school customers."[63] Finally, it is very important to note that SB 1524 was NOT passed by the Legislature and never reached a vote by the entire Senate or any vote in the House of Representatives.[64] Therefore, based on the fact that SB 1524 failed to pass, it would be wrong to determine, "this action indicates Legislature approval and expansion of the discount to cover other entities in the EPE service territory should benefit."[65]

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[62] PURA 36.007(d).

[63] Tex. S.B. 1524 at lines 6 – 11, 74th Leg. R.S. (1995).

[64] *Id.*; SB 1524 was voted out of the Senate Committee on State Affairs on May 11, 1995 and died.

[65] Direct Testimony and Exhibits of James W. Daniel at 12: 8 – 9.

In addition, Mr. Daniel argued the Rate 41 class should receive a discount "similar to the discounts provided in PURA for institutions of higher education and for military bases."[66] However, the discounts provided in PURA for institutions of higher education and military bases were established by the Texas Legislature in 1995 and 2003, respectively. If the Texas Legislature had intended to provide the entities included in Rate 41 with a similar discount, they have had ample opportunity to do so. It would be inappropriate to assume the Texas Legislature intended to provide for the discount that Mr. Daniel proposes.

Q. WHAT IS YOUR RECOMMENDATION CONCERNING THE DISTRIBUTION OF BASE RATE REVENUE INCREASES?

A. I recommend the Commission reject the proposals offered by Mr. Pollock, Mr. Higgins, and Mr. Daniel.

I continue to recommend the base revenue increase distribution among customer classes reflect moderation. I recommend the revenue increases be developed so that no firm service rate class be assigned an increase that is more than 150% of the Texas retail average base revenue increase percentage and no firm service class be assigned an increase that is less than 50% of the Texas retail average base revenue increase percentage.

VIII. EPE'S ENERGY LOSS FACTORS

Q. PLEASE DISCUSS THE ISSUES THAT PARTIES IDENTIFIED WITH EPE'S LOSS STUDY AND TRANSMISSION ENERGY LOSS FACTORS.

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[66] *Id.* at 12:14 – 17.

A. Mr. Pollock and Mr. Higgins raised concerns about the fact that EPE's energy loss study produced transmission energy loss factors that were higher than the transmission demand loss factors. Mr. Higgins only expressed concern about this issue but did not make any recommendations related to his concern.[67] Mr. Pollock's testimony contained significantly more discussion on this topic. Mr. Pollock stated, "EPE's Loss Study is flawed because, for deliveries at the substation and transmission voltages, the energy loss factor is higher than the (peak) demand loss factor."[68] Mr. Pollock also recommended an unsupported adjustment to reduce EPE's transmission energy loss factors to 90% of the transmission demand loss factors.[69]

Q. DO YOU AGREE WITH MR. POLLOCK'S ASSERTION THAT EPE'S LOSS STUDY IS FLAWED BECAUSE THE ENERGY LOSS FACTORS FOR SERVICE DELIVERED AT TRANSMISSION VOLTAGE AND PRIMARY SUBSTATION ARE HIGHER THAN THEIR RESPECTIVE DEMAND LOSS FACTORS?

A. No, I do not agree. Furthermore, as shown on Attachment EDE-8CR, the currently approved transmission voltage energy loss factors for two of the other three non-ERCOT electric utilities, SPS and Entergy Texas, are higher than their respective transmission demand loss factors.

Q. PLEASE DISCUSS MR. POLLOCK'S RECOMMENDATION TO ADJUST THE ENERGY LOSS FACTORS FOR TRANSMISSION VOLTAGE AND PRIMARY SUBSTATION TO BE 90% OF THE DEMAND LOSS FACTORS.

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[67] Direct Testimony of Kevin C. Higgins at 27:5 – 10.

[68] Direct Testimony and Exhibits of Jeffry Pollock at 2: 21 – 23.

[69] *Id.* at 3:6 – 10 and 39:9 – 10.

A. There is no basis for Mr. Pollock's proposal. He states, "This would approximate the relationships between the energy and demand loss factors for primary and secondary services. It would also be consistent with industry standard practice." I have prepared or directed the preparation of several loss studies since the late 1980s and I have no familiarity with Mr. Pollock's claimed industry standard practice of assigning transmission voltage and distribution substation energy loss factors based on the relationship of primary and secondary energy loss factors to their respective demand loss factors.

Attachment EDE-9CR provides a comparison of the energy loss factors to the demand loss factors at all service voltage levels and for all four of the non-ERCOT IOUs. Attachment EDE-9CR does not reveal any consistent or standard relationship between energy and demand loss factors by service voltage levels for any of the four non-ERCOT IOUs.

Q. DID MR. POLLOCK PROPOSE TO MAKE ANY CORRESPONDING ADJUSTMENTS TO THE PRIMARY LINE AND SECONDARY VOLTAGE ENERGY LOSS FACTORS?

A. No. Mr. Pollock did not propose any corresponding adjustments to the energy loss factors for service delivered at primary lines or at secondary voltages. As a result, his adjustment to only reduce the energy loss factors applicable to transmission and primary substation loads would inappropriately reduce the allocation of base rate and fuel costs to the customer classes served at those voltages and inappropriately shift base rate and fuel costs on to the customer classes that are served from primary lines or at secondary voltages.

Q. WHAT IS YOUR RECOMMENDATION CONCERNING EPE'S LOSS FACTORS?

A. Mr. Pollock's recommended adjustments to EPE's energy loss adjustment factors should be rejected and EPE's current loss factors, which were approved by the Commission in Docket No. 50058, are reasonable and should not be adjusted.

IX. CONCLUSION

Q. PLEASE SUMMARIZE THE RECOMMENDATIONS CONTAINED IN THIS TESTIMONY.

A. In this testimony, I recommend the following:

- Approval of EPE's proposal to use 4CP demands to calculate the load factor weighting in the calculation of the 4CP-A&E allocator;
- Approval of EPE's proposal to use energy and coincident peak demands that have been adjusted for year-end customers and weather normalization for the calculation of the load factor weighting in the calculation of the 4CP-A&E allocator;
- Approval of EPE's proposal to allocate FERC Account 556 - System Control and Load Dispatching Expense and FERC Account 561 – Load Dispatching based on the average of 12 coincident peak ("12CP") demands;
- Investment in EPE's 69 kV transmission lines and associated costs should be allocated to all customer classes, including those customer classes served at 115 kV;
- The base revenue increase distribution among customer classes should reflect moderation and no firm service rate class should be increased by more than 150% of

the Texas retail average increase percentage and no firm service rate class should be increased by less than 50% of the Texas retail average percentage increase; and

- EPE's current loss factors, which were approved by the Commission in Docket No. 50058, are reasonable and should not be adjusted.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

ATTACHMENTS

Comparison of
Retail Electric Customer Mix for Each Non-ERCOT IOU
2020

FERC Form 1 Retail Groups	EPE 2020 Retail MWh Sales	EPE % of Total Retail	Entergy Texas 2020 Retail MWh Sales	Entergy Texas % of Total Retail	SWEPCO 2020 Retail MWh Sales	SWEPCO % of Total Retail	SPS 2020 Retail MWh Sales	SPS % of Total Retail
Residential	3,323,039	41.0%	6,145,701	32.9%	5,987,691	36.8%	3,786,587	18.4%
Small Commercial and Industrial	2,310,036	28.5%	4,386,324	23.5%	5,295,987	32.6%	4,819,471	23.4%
Large Commercial and Industrial	978,758	12.1%	7,884,794	42.2%	4,891,281	30.1%	11,452,144	55.7%
Public Street and Highway Lightin(	39,886	0.5%	36,389	0.2%	78,964	0.5%	36,980	0.2%
Other Sales to Public Authorities	1,447,741	17.9%	223,370	1.2%			479,075	2.3%
Total Retail Sales	8,099,460	100.0%	18,676,578	100.0%	16,253,923	100.0%	20,574,257	100.0%

Source of Data: 2020 FERC Form No. 1 Report filings, pages 300 - 301

Comparison of
Historical 4CP to 1CP Relationships and Load Factors for
All Non-ERCOT Fully Integrated Electric Utilities

Year	June CP	July CP	August CP	September CP	4CP	Annual CP	4CP % of 1CP	Annual MWh	Average Demand	4 CP Load Factor	1 CP Load Factor
El Paso Electric											
2016	1,863	1,877	1,787	1,620	1,786.75	1,877	95.2%	8,444,749	961.38	53.8%	51.2%
2017	1,935	1,792	1,773	1,685	1,796.25	1,935	92.8%	8,448,832	964.48	53.7%	49.8%
2018	1,921	1,929	1,864	1,701	1,853.75	1,929	96.1%	8,611,069	983.00	53.0%	51.0%
2019	1,856	1,885	1,985	1,775	1,875.25	1,985	94.5%	8,591,647	980.78	52.3%	49.4%
2020	1,932	2,173	2,100	1,870	2,018.75	2,173	92.9%	8,718,503	992.54	49.2%	45.7%
Entergy Texas											
2016	3,269	3,346	3,536	3,321	3,368.00	3,536	95.2%	18,718,318	2,130.96	63.3%	60.3%
2017	3,244	3,473	3,450	2,903	3,267.50	3,473	94.1%	18,689,902	2,133.55	65.3%	61.4%
2018	3,452	3,534	3,437	3,334	3,439.25	3,534	97.3%	19,676,039	2,246.12	65.3%	63.6%
2019	3,483	3,510	3,652	3,427	3,518.00	3,652	96.3%	19,600,600	2,237.51	63.6%	61.3%
2020	3,466	3,663	3,699	3,297	3,531.25	3,699	95.5%	19,758,617	2,249.39	63.7%	60.8%
Southwestern Electric Power Company											
2016	4,623	4,906	4,921	4,477	4,731.75	4,921	96.2%	24,124,480	2,746.41	58.0%	55.8%
2017	4,405	4,768	4,537	4,422	4,533.00	4,768	95.1%	23,686,530	2,703.94	59.7%	56.7%
2018	4,635	4,834	4,563	4,451	4,620.75	4,834	95.6%	23,748,823	2,711.05	58.7%	56.1%
2019	4,307	4,436	4,727	4,493	4,490.75	4,727	95.0%	23,386,336	2,669.67	59.4%	56.5%
2020	4,057	4,294	4,350	3,919	4,155.00	4,350	95.5%	21,441,073	2,440.92	58.7%	56.1%
Southwestern Public Service Company											
2016	4,593	4,836	4,663	4,167	4,564.75	4,836	94.4%	25,570,117	2,910.99	63.8%	60.2%
2017	4,350	4,374	3,976	4,121	4,205.25	4,374	96.1%	24,905,470	2,843.09	67.6%	65.0%
2018	4,447	4,648	4,391	3,950	4,359.00	4,648	93.8%	26,129,134	2,982.78	68.4%	64.2%
2019	3,944	4,223	4,261	4,146	4,143.50	4,261	97.2%	25,249,073	2,882.31	69.6%	67.6%
2020	3,746	4,023	4,118	3,829	3,929.00	4,118	95.4%	23,322,809	2,655.15	67.6%	64.5%

Source of Data: Filed FERC Form No. 1 Annual Reports, Page 401b

Comparison of
EPE and SPS Peak Hours for 2020

	El Paso Electric Company				Southwestern Public Service Company			
Line	Date	Hour Ending	MW Load	% of Peak	Date	Hour Ending	MW Load	% of Peak
1	7/13/2020	16	2173	100.00%	7/14/2020	17	4,656	100.00%
2	7/13/2020	15	2157	99.26%	7/14/2020	16	4,634	99.52%
3	7/13/2020	17	2151	98.99%	7/14/2020	18	4,626	99.36%
4	7/14/2020	16	2110	97.10%	7/13/2020	17	4,600	98.80%
5	7/13/2020	14	2104	96.82%	7/13/2020	18	4,578	98.32%
6	8/12/2020	16	2100	96.64%	7/14/2020	19	4,570	98.14%
7	8/14/2020	15	2100	96.64%	7/9/2020	17	4,568	98.10%
8	8/14/2020	16	2099	96.59%	7/14/2020	15	4,562	97.97%
9	7/10/2020	16	2097	96.50%	7/13/2020	16	4,560	97.93%
10	7/13/2020	18	2097	96.50%	7/9/2020	16	4,552	97.77%
11	7/10/2020	15	2095	96.41%	8/13/2020	17	4,528	97.25%
12	8/12/2020	15	2093	96.32%	7/13/2020	19	4,510	96.86%
13	7/10/2020	17	2090	96.18%	8/12/2020	17	4,509	96.83%
14	8/12/2020	17	2089	96.13%	7/9/2020	18	4,505	96.76%
15	7/14/2020	15	2086	96.00%	7/10/2020	16	4,504	96.73%
16	7/09/2020	16	2084	95.90%	8/13/2020	18	4,498	96.60%
17	8/11/2020	15	2075	95.49%	8/28/2020	17	4,494	96.51%
18	7/09/2020	17	2073	95.40%	8/12/2020	18	4,490	96.43%
19	8/11/2020	16	2072	95.35%	7/10/2020	17	4,487	96.38%
20	7/14/2020	17	2071	95.31%	8/28/2020	18	4,479	96.19%
21	8/14/2020	17	2066	95.08%	8/13/2020	16	4,477	96.15%
22	7/09/2020	15	2065	95.03%	7/11/2020	17	4,472	96.05%
23					7/10/2020	18	4,471	96.03%
24					7/13/2020	15	4,471	96.02%
25					7/9/2020	15	4,463	95.85%
26					8/28/2020	16	4,459	95.77%
27					8/12/2020	16	4,459	95.76%
28					8/14/2020	16	4,451	95.59%
29					7/9/2020	19	4,451	95.59%
30					7/11/2020	18	4,446	95.49%
31					7/11/2020	16	4,445	95.46%
32					7/14/2020	20	4,434	95.23%
33					7/10/2020	15	4,431	95.16%
34					7/14/2020	14	4,425	95.04%

Sources: EPE Response to OPUC 11th RFI, Question No. 1-22 and SPS Response to OPUC 10th RFI, Question No. 10-20 (Docket No. 51802)

B. Energy Weighting Methods

There is evidence that energy loads are a major determinant of production plant costs. Thus, cost of service analysis may incorporate energy weighting into the treatment of production plant costs. One way to incorporate an energy weighting is to classify part of the utility's production plant costs as energy-related and to allocate those costs to classes on the basis of class energy consumption. Table 4-4 shows allocators for the example utility for total energy, on-peak energy, and off-peak energy use.

In some cases, an energy allocator (annual KWH consumption or average demand) is used to allocate part of the production plant costs among the classes, but part or all of these costs remain classified as demand-related. Such methods can be characterized as partial energy weighting methods in that they take the first step of allocating some portion of production plant costs to the classes on the basis of their energy loads but do not take the second step of classifying the costs as energy- related.

1. Average and Excess Method

Objective: The cost of service analyst may believe that average demand rather than coincident peak demand is a better allocator of production plant costs. The average and excess method is an appropriate method for the analyst to use. The method allocates production plant costs to rate classes using factors that combine the classes' average demands and non-coincident peak (NCP) demands.

Data Requirements: The required data are: the annual maximum and average demands for each customer class and the system load factor. All production plant costs are usually classified as demand-related. The allocation factor consists of two parts. The first component of each class's allocation factor is its proportion of total average demand (or energy consumption) times the system load factor. This effectively uses an average demand or total energy allocator to allocate that portion of the utility's generating capacity that would be needed if all customers used energy at a constant 100 percent load factor. The second component of each class's allocation factor is called the "excess demand factor." It is the proportion of the difference between the sum of all classes' non-coincident peaks and the system average demand. The difference may be negative for curtailable rate classes. This component is multiplied by the remaining proportion of production plant -- i.e., by 1 minus the system load factor -- and then added to the first component to obtain the "total allocator." Table 4-10A shows the derivation of the allocation factors and the resulting allocation of production plant costs using the average and excess method.

TABLE 4-10A

CLASS ALLOCATION FACTORS AND ALLOCATED PRODUCTION PLANT REVENUE REQUIREMENT USING THE AVERAGE AND EXCESS METHOD

Class Rate	Demand Allocation Factor - NCP MW	Average Demand (MW)	Excess Demand (NCP MW - Avg. MW)	Average Demand Component of Alloc. Factor	Excess Demand Component of Alloc. Factor	Total Allocation Factor (%)	Class Production Plant Revenue Requirement
DOM	5,357	2,440	2,917	17.95	18.51	36.46	386,683,685
LSMP	5,062	2,669	2,393	19.64	15.18	34.82	369,289,317
LP	3,385	2,459	926	18.09	5.88	23.97	254,184,071
AG&P	572	254	318	1.87	2.02	3.89	41,218,363
SL	126	58	68	0.43	0.43	0.86	9,101,564
TOTAL	14,502	7,880	6,622	57.98	42.02	100.00	$1,060,476,000

Notes: The system load factor is 57.98 percent, calculated by dividing the average demand of 7,880 MW by the systen coincident peak demand of 13,591 MW. This example shows production plant classified as demand-related.

Some columns may not add to indicated totals due to rounding.

If your objective is -- as it should be using this method --to reflect the impact of average demand on production plant costs, then it is a mistake to allocate the excess demand with a coincident peak allocation factor because it produces allocation factors that are identical to those derived using a CP method. Rather, use the NCP to allocate the excess demands.

The example on Table 4-10B illustrates this problem. In the example, the excess demand component of the allocation factor for the Street Lighting and Outdoor Lighting (SL/OL) class is negative and reduces the class's allocation factor to what it would be if a single CP method were used in the first place. (See third column of Table 4-3.)

TABLE 4-10B

CLASS ALLOCATION FACTORS AND ALLOCATED PRODUCTION PLANT REVENUE REQUIREMENT USING THE AVERAGE AND EXCESS METHOD (SINGLE CP DEMAND FACTOR)

Rate Class	Demand Allocation Factor - Single CP NCP MW	Average Demand (MW)	Excess Demand (Single CP MW - Avg. MW)	Average Demand Component of Allocation Factor	Excess Demand Component of Allocation Factor	Total Allocation Factor (%)	Class Production Plant Revenue Requirement
DOM	4,735	2,440	2,295	17.95	16.89	34.84	369,461,692
LSMP	5,062	2,669	2,393	19.64	17.61	37.25	394,976,787
LP	3,347	2,459	888	18.09	6.53	24.63	261,159,089
AG&P	447	254	193	1.87	1.42	3.29	34,878,432
SL	0	58	-58	0.43	-0.43	0.00	0
TOTAL	13,591	7,880	5,711	57.98	42.02	100.00	$1,060,476,000

Notes: The system load factor is 57.98 percent, calculated by dividing the average demand of 7,880 MW by the systen coincident peak demand of 13,591 MW. This example shows all production plant classified as demand-related. Note that the total allocation factors are exactly equal to those derived using the single coincident peak method shown in the third column of Table 4-3.

Some columns may not add to indicated totals due to rounding.

Some analysts argue that the percentage of total production plant that is equal to the system load factor percentage should be classified as energy-related and not demand-related. This could be important because, although classifying the system load factor percentage as energy-related might not affect the allocation among classes, it could significantly affect the apportionment of costs within rate classes. Such a classification could also affect the allocation of production plant costs to interruptible service, if the utility or the regulatory authority allocated energy-related production plant costs but not demand-related production plant costs to the interruptible class. Table 4-10C presents the allocation factors and production plant revenue requirement allocations for an average and excess cost of service study with the system load factor percentage classified as energy-related.

TABLE 4-10C

CLASS ALLOCATION FACTORS AND ALLOCATED PRODUCTION PLANT REVENUE REQUIREMENT USING THE AVERAGE AND EXCESS METHOD

(AVERAGE DEMAND PROPORTION ALLOCATED ON ENERGY)

Rate Class	Energy Allocation Factor - Average MW	Energy Allocatn. Factor (%)	Energy-Related Production Plant Revenue Requirement	Excess Demand Allocation Factor (NCP MW - Avg. MW)	Excess Demand Alloctn. Factor (Percent)	Demand-Related Production Plant Revenue Requirement	Class Production Plant Revenue Requiremnt
DOM	2,440	30.96	190,387,863	2,917	44.05	196,294,822	386,682,685
LSMP	2,669	33.87	208,256,232	2,393	36.14	161,033,085	369,289,317
LP	2,459	31.21	191,870,391	926	13.98	62,313,680	254,184,071
AG&P	254	3.22	19,819,064	318	4.80	21,399,298	41,218,363
SL	58	0.74	4,525,613	68	1.03	4,575,951	9,101,564
TOTAL	7,880	100.00	614,859,163	6,622	100.00	445,616,837	1,060,476,000

Notes: The system load factor is 57.98 percent (7,880 MW/13,591 MW). Thus, 57.98 percent of total production plant revenue requirement is classified as energy-related and allocated to all classes on the basis of their proportions of average system demand. The remaining 42.02 percent is classified as demand-related and allocated to the classes according to their proportions of excess (NCP - average) demand, and allocated to the firm service classes according to their proportions of excess (NCP - average) demand.

Some columns may not add to indicated totals due to rounding.

2. Equivalent Peaker Methods

Objective: Equivalent peaker methods are based on generation expansion planning practices, which consider peak demand loads and energy loads separately in determining the <u>need</u> for additional generating capacity and the most cost-effective <u>type</u> of capacity to be added. They generally result in significant percentages (40 to 75 percent) of total production plant costs being classified as energy-related, with the results that energy unit costs are relatively high and the revenue responsibility of high load factor classes and customers is significantly greater than indicated by pure peak demand responsibility methods.

Comparison of
4CP-A&E with Alternative Load Factor Calculations
by Texas Retail Class

Rate Class	4CP-A&E with 4CP Load Factor	4CP-A&E with 1CP Load Factor	Nominal Difference	Relative Difference
Residential Service	54.847%	55.859%	**1.012%**	**1.846%**
Small General Service	4.723%	4.731%	**0.008%**	**0.163%**
Outdoor Recreational Lighting Service	0.030%	0.028%	-0.003%	-8.583%
Street Lighting	0.296%	0.271%	-0.025%	-8.583%
Traffic Signals	0.017%	0.016%	-0.001%	-8.583%
Municipal Pumping Service	1.591%	1.486%	-0.106%	-6.649%
Electrolytic Refining Service	0.516%	0.501%	-0.014%	-2.784%
Off Peak Water Heating Service	0.042%	0.038%	-0.004%	-8.583%
Irrigation Service	0.096%	0.099%	**0.002%**	**2.588%**
General Service	21.028%	20.737%	-0.290%	-1.381%
Large Power Service	6.849%	6.572%	-0.277%	-4.050%
Petroleum Refining Service	2.765%	2.579%	-0.187%	-6.754%
Private Area Lighting Service	0.220%	0.202%	-0.019%	-8.583%
Electric Furnace Rate	0.341%	0.341%	-0.001%	-0.186%
Military Reservation Service	3.482%	3.399%	-0.082%	-2.364%
Cotton Gin Service	0.013%	0.012%	-0.001%	-8.583%
City and County Service	3.142%	3.131%	-0.012%	-0.375%
Texas Total Firm Load	100.000%	100.000%	0.000%	0.000%

SOAH DOCKET NO. 473-21-2606
PUC DOCKET NO. 52195

APPLICATION OF EL PASO ELECTRIC COMPANY TO CHANGE RATES	§ § §	BEFORE THE STATE OFFICE OF ADMINISTRATIVE HEARINGS

EL PASO ELECTRIC COMPANY'S RESPONSE TO
TEXAS INDUSTRIAL ENERGY CONSUMERS'
EIGHTH REQUEST FOR INFORMATION
QUESTION NOS. TIEC 8-1 THROUGH TIEC 8-8

TIEC 8-6:

Please confirm that customers served at 115 kV voltage (i.e. Rate 25 T/115, Rate 26, Rate 30 T/115, Rate 31, and Rate 38 115 kV customers) do not utilize EPE's 69 kV lines. If denied, please explain how EPE's 69 kV lines are directly utilized in the provision of service to customers served at 115 kV.

RESPONSE:

The 115 kV and 69 kV transmission systems are part of an interconnected system. Power flowing to customers taking service at transmission voltages (115 kV or 69 kV) can easily flow from the 69 kV system to the 115 kV system, or conversely, from the 115 kV system to the 69 kV system, depending on the system configuration at any point in time. Therefore, the power flowing to a customer taking transmission service at 115 kV could be utilizing a path that includes the 69 kV system, along with the 115 kV system.

Refer to El Paso Electric Company ("EPE") witness Adrian Hernandez's direct testimony (page 11, lines 12 to 13) for EPE's cost allocation approach.

Preparer:	Darcy Welch	Title:	Supervisor – Financial Analysis and Planning
Sponsor:	R. Clay Doyle	Title:	Vice President – Transmission and Distribution
	Adrian Hernandez		Senior Rate Analyst – Rates

Comparison of
Historical Annual Energy Usage by Customer Class
Summary for 2019 and 2020

Rate Class	2019 Annual MWh	% Composition of Total Texas	2020 Annual MWh	% Composition of Total Texas	Nonminal Change in % Composition from 2019	Relative % Change in Composition from 2019
Residential Service	2,261,548	38.181%	2,526,537	41.930%	3.749%	9.818%
Small General Service	266,927	4.506%	275,543	4.573%	0.066%	1.473%
Outdoor Recreational Lighting Service	5,561	0.094%	3,659	0.061%	-0.033%	-35.318%
Street Lighting	34,677	0.585%	35,538	0.590%	0.004%	0.740%
Traffic Signals	2,660	0.045%	2,651	0.044%	-0.001%	-2.037%
Municipal Pumping Service	178,939	3.021%	173,330	2.877%	-0.144%	-4.782%
Electrolytic Refining Service	34,043	0.575%	42,605	0.707%	0.132%	23.021%
Off Peak Water Heating Service	5,749	0.097%	5,348	0.089%	-0.008%	-8.552%
Irrigation Service	4,709	0.079%	4,059	0.067%	-0.012%	-15.273%
General Service	1,567,470	26.463%	1,494,847	24.808%	-1.655%	-6.255%
Large Power Service	642,431	10.846%	617,703	10.251%	-0.595%	-5.484%
Petroleum Refining Service	332,242	5.609%	314,642	5.222%	-0.387%	-6.907%
Private Area Lighting Service	25,685	0.434%	26,176	0.434%	0.001%	0.179%
Electric Furnace Rate	21,084	0.356%	19,888	0.330%	-0.026%	-7.273%
Military Reservation Service	283,584	4.788%	280,364	4.653%	-0.135%	-2.816%
Cotton Gin Service	2,340	0.040%	1,596	0.026%	-0.013%	-32.947%
City and County Service	253,570	4.281%	201,181	3.339%	-0.942%	-22.010%
Texas Total Firm Load	5,923,221	100.000%	6,025,668	100.000%	0.000%	

Comparison of
Historical Annual Energy Usage by Customer Class
For the Years of 2010 - 2020

Residential Service

Year	Annual MWh	% of Total Texas Firm	Change from Previous Year	Relative % Change from Previous Year
2010	1,848,213	33.973%	NA	NA
2011	1,921,761	34.189%	0.216%	0.634%
2012	1,964,652	34.300%	0.111%	0.325%
2013	1,977,276	34.553%	0.253%	0.738%
2014	1,970,304	34.949%	0.396%	1.147%
2015	2,079,033	35.719%	0.770%	2.202%
2016	2,118,746	36.292%	0.574%	1.606%
2017	2,132,139	36.556%	0.264%	0.727%
2018	2,258,498	37.882%	1.325%	3.626%
2019	2,261,548	38.181%	0.299%	0.790%
2020	2,526,537	41.930%	3.749%	9.818%

Off-Peak Water Heating Service

Year	Annual MWh	% of Total Texas Firm	Change from Previous Year	Relative % Change from Previous Year
2010	20,243	0.372%	NA	NA
2011	18,550	0.330%	-0.042%	-11.314%
2012	17,466	0.305%	-0.025%	-7.597%
2013	13,718	0.240%	-0.065%	-21.386%
2014	11,335	0.201%	-0.039%	-16.127%
2015	9,772	0.168%	-0.033%	-16.501%
2016	8,820	0.151%	-0.017%	-10.013%
2017	7,703	0.132%	-0.019%	-12.582%
2018	6,888	0.116%	-0.017%	-12.518%
2019	5,749	0.097%	-0.018%	-15.991%
2020	5,348	0.089%	-0.008%	-8.552%

Small General Service

Year	Annual MWh	% of Total Texas Firm	Change from Previous Year	Relative % Change from Previous Year
2010	331,422	6.092%	NA	NA
2011	264,540	4.706%	-1.386%	-22.748%
2012	243,674	4.254%	-0.452%	-9.606%
2013	242,197	4.232%	-0.022%	-0.512%
2014	245,170	4.349%	0.116%	2.750%
2015	262,575	4.511%	0.162%	3.733%
2016	277,181	4.748%	0.237%	5.247%
2017	290,888	4.987%	0.240%	5.045%
2018	291,771	4.894%	-0.094%	-1.875%
2019	266,927	4.506%	-0.387%	-7.916%
2020	275,543	4.573%	0.066%	1.473%

Outdoor Recreational Lighting Service

Year	Annual MWh	% of Total Texas Firm	Change from Previous Year	Relative % Change from Previous Year
2010	5,297	0.097%	NA	NA
2011	5,384	0.096%	-0.002%	-1.632%
2012	5,276	0.092%	-0.004%	-3.820%
2013	5,083	0.089%	-0.003%	-3.581%
2014	4,962	0.088%	-0.001%	-0.898%
2015	5,283	0.091%	0.003%	3.111%
2016	5,364	0.092%	0.001%	1.240%
2017	5,179	0.089%	-0.003%	-3.369%
2018	5,711	0.096%	0.007%	7.879%
2019	5,561	0.094%	-0.002%	-1.979%
2020	3,659	0.061%	-0.033%	-35.318%

Comparison of
Historical Annual Energy Usage by Customer Class
For the Years of 2010 - 2020

Year	Street Lighting Service: Annual MWh	Street Lighting Service: % of Total Texas Firm	Street Lighting Service: Change from Previous Year	Street Lighting Service: Relative % Change from Previous Year	Traffic Signals Service: Annual MWh	Traffic Signals Service: % of Total Texas Firm	Traffic Signals Service: Change from Previous Year	Traffic Signals Service: Relative % Change from Previous Year
2010	40,465	0.744%	NA	NA	0	0.000%	NA	NA
2011	35,845	0.638%	-0.106%	-14.266%	1,432	0.025%	NA	NA
2012	37,079	0.647%	0.010%	1.512%	2,509	0.044%	0.018%	71.953%
2013	37,823	0.661%	0.014%	2.103%	2,532	0.044%	0.000%	1.023%
2014	30,440	0.540%	-0.121%	-18.309%	2,554	0.045%	0.001%	2.370%
2015	33,304	0.572%	0.032%	5.971%	2,601	0.045%	-0.001%	-1.348%
2016	33,193	0.569%	-0.004%	-0.632%	2,627	0.045%	0.000%	0.698%
2017	34,182	0.586%	0.018%	3.079%	2,649	0.045%	0.000%	0.940%
2018	34,541	0.579%	-0.007%	-1.147%	2,663	0.045%	-0.001%	-1.682%
2019	34,677	0.585%	0.006%	1.053%	2,660	0.045%	0.000%	0.576%
2020	35,538	0.590%	0.004%	0.740%	2,651	0.044%	-0.001%	-2.037%

Year	Water Pumping Service: Annual MWh	Water Pumping Service: % of Total Texas Firm	Water Pumping Service: Change from Previous Year	Water Pumping Service: Relative % Change from Previous Year	Electrolytic Refining Service: Annual MWh	Electrolytic Refining Service: % of Total Texas Firm	Electrolytic Refining Service: Change from Previous Year	Electrolytic Refining Service: Relative % Change from Previous Year
2010	144,503	2.656%	NA	NA	69,989	1.287%	NA	NA
2011	155,904	2.774%	0.117%	4.419%	52,491	0.934%	-0.353%	-27.414%
2012	170,674	2.980%	0.206%	7.432%	55,616	0.971%	0.037%	3.978%
2013	178,032	3.111%	0.131%	4.410%	55,508	0.970%	-0.001%	-0.100%
2014	172,234	3.055%	-0.056%	-1.801%	54,100	0.960%	-0.010%	-1.071%
2015	167,885	2.884%	-0.171%	-5.589%	55,531	0.954%	-0.006%	-0.581%
2016	160,838	2.755%	-0.129%	-4.484%	57,558	0.986%	0.032%	3.340%
2017	162,334	2.783%	0.028%	1.026%	56,208	0.964%	-0.022%	-2.253%
2018	163,949	2.750%	-0.033%	-1.198%	41,423	0.695%	-0.269%	-27.904%
2019	178,939	3.021%	0.271%	9.857%	34,043	0.575%	-0.120%	-17.278%
2020	173,330	2.877%	-0.144%	-4.782%	42,605	0.707%	0.132%	23.021%

Comparison of
Historical Annual Energy Usage by Customer Class
For the Years of 2010 - 2020

	Irrigation Service				General Service			
Year	Annual MWh	% of Total Texas Firm	Change from Previous Year	Relative % Change from Previous Year	Annual MWh	% of Total Texas Firm	Change from Previous Year	Relative % Change from Previous Year
2010	3,065	0.056%	NA	NA	1,375,950	25.292%	NA	NA
2011	3,416	0.061%	0.004%	7.856%	1,465,356	26.069%	0.777%	3.072%
2012	3,953	0.069%	0.008%	13.568%	1,505,224	26.279%	0.210%	0.805%
2013	5,235	0.091%	0.022%	32.545%	1,483,234	25.920%	-0.359%	-1.368%
2014	5,419	0.096%	0.005%	5.062%	1,490,915	26.446%	0.526%	2.030%
2015	5,438	0.093%	-0.003%	-2.794%	1,515,491	26.037%	-0.409%	-1.547%
2016	5,268	0.090%	-0.003%	-3.415%	1,543,428	26.438%	0.401%	1.539%
2017	4,154	0.071%	-0.019%	-21.071%	1,529,750	26.228%	-0.210%	-0.792%
2018	4,766	0.080%	0.009%	12.240%	1,571,184	26.353%	0.125%	0.478%
2019	4,709	0.079%	0.000%	-0.556%	1,567,470	26.463%	0.110%	0.416%
2020	4,059	0.067%	-0.012%	-15.273%	1,494,847	24.808%	-1.655%	-6.255%

	Large Power Service				Petroleum Refinery Service			
Year	Annual MWh	% of Total Texas Firm	Change from Previous Year	Relative % Change from Previous Year	Annual MWh	% of Total Texas Firm	Change from Previous Year	Relative % Change from Previous Year
2010	665,050	12.225%	NA	NA	335,173	6.161%	NA	NA
2011	680,324	12.103%	-0.122%	-0.994%	314,935	5.603%	-0.558%	-9.061%
2012	687,383	12.001%	-0.102%	-0.847%	333,102	5.815%	0.213%	3.796%
2013	696,807	12.177%	0.176%	1.467%	331,438	5.792%	-0.024%	-0.405%
2014	685,419	12.158%	-0.019%	-0.154%	318,713	5.653%	-0.139%	-2.393%
2015	686,129	11.788%	-0.370%	-3.043%	384,567	6.607%	0.954%	16.870%
2016	674,429	11.552%	-0.236%	-1.999%	346,522	5.936%	-0.671%	-10.162%
2017	674,624	11.567%	0.014%	0.124%	339,078	5.814%	-0.122%	-2.056%
2018	652,563	10.945%	-0.621%	-5.371%	336,247	5.640%	-0.174%	-2.989%
2019	642,431	10.846%	-0.099%	-0.909%	332,242	5.609%	-0.031%	-0.545%
2020	617,703	10.251%	-0.595%	-5.484%	314,642	5.222%	-0.387%	-6.907%

Comparison of
Historical Annual Energy Usage by Customer Class
For the Years of 2010 - 2020

	Area Lighting Service				Electric Furnace Service			
Year	Annual MWh	% of Total Texas Firm	Change from Previous Year	Relative % Change from Previous Year	Annual MWh	% of Total Texas Firm	Change from Previous Year	Relative % Change from Previous Year
2010	25,596	0.471%	NA	NA	21,986	0.404%	NA	NA
2011	26,023	0.463%	-0.008%	-1.602%	24,193	0.430%	0.026%	6.497%
2012	26,374	0.460%	-0.003%	-0.542%	24,767	0.432%	0.002%	0.467%
2013	26,687	0.466%	0.006%	1.282%	21,533	0.376%	-0.056%	-12.978%
2014	26,771	0.475%	0.008%	1.822%	22,636	0.402%	0.025%	6.707%
2015	26,963	0.463%	-0.012%	-2.446%	21,791	0.374%	-0.027%	-6.759%
2016	27,081	0.464%	0.001%	0.136%	17,397	0.298%	-0.076%	-20.404%
2017	26,961	0.462%	-0.002%	-0.349%	21,981	0.377%	0.079%	26.466%
2018	26,857	0.450%	-0.012%	-2.548%	21,443	0.360%	-0.017%	-4.564%
2019	25,685	0.434%	-0.017%	-3.738%	21,084	0.356%	-0.004%	-1.033%
2020	26,176	0.434%	0.001%	0.179%	19,888	0.330%	-0.026%	-7.273%

	Military Reservation Service				Cotton Gin Service			
Year	Annual MWh	% of Total Texas Firm	Change from Previous Year	Relative % Change from Previous Year	Annual MWh	% of Total Texas Firm	Change from Previous Year	Relative % Change from Previous Year
2010	234,922	4.318%	NA	NA	1,786	0.033%	NA	NA
2011	339,896	6.047%	1.729%	40.030%	2,077	0.037%	0.004%	12.545%
2012	338,433	5.909%	-0.138%	-2.287%	1,771	0.031%	-0.006%	-16.302%
2013	338,224	5.910%	0.002%	0.033%	689	0.012%	-0.019%	-61.056%
2014	300,427	5.329%	-0.582%	-9.839%	1,018	0.018%	0.006%	49.911%
2015	266,944	4.586%	-0.743%	-13.938%	1,430	0.025%	0.007%	36.076%
2016	265,207	4.543%	-0.043%	-0.948%	1,698	0.029%	0.005%	18.408%
2017	269,120	4.614%	0.071%	1.572%	2,530	0.043%	0.014%	49.115%
2018	270,139	4.531%	-0.083%	-1.802%	2,117	0.036%	-0.008%	-18.135%
2019	283,584	4.788%	0.257%	5.664%	2,340	0.040%	0.004%	11.262%
2020	280,364	4.653%	-0.135%	-2.816%	1,596	0.026%	-0.013%	-32.947%

Comparison of
Historical Annual Energy Usage by Customer Class
For the Years of 2010 - 2020

	City & County Service				**Total Texas Retail -Firm**			
Year	Annual MWh	% of Total Texas Firm	Change from Previous Year	Relative % Change from Previous Year	Annual MWh	% of Total Texas Firm	Change from Previous Year	Relative % Change from Previous Year
2010	316,527	5.818%	NA	NA	5,440,187	100.00%		
2011	308,888	5.495%	-0.323%	-5.553%	5,621,014	100.00%		
2012	309,890	5.410%	-0.085%	-1.547%	5,727,844	100.00%		
2013	306,419	5.355%	-0.056%	-1.027%	5,722,436	100.00%		
2014	295,193	5.236%	-0.119%	-2.214%	5,637,609	100.00%		
2015	295,818	5.082%	-0.154%	-2.938%	5,820,555	100.00%		
2016	292,639	5.013%	-0.070%	-1.370%	5,837,996	100.00%		
2017	272,997	4.681%	-0.332%	-6.624%	5,832,477	100.00%		
2018	271,213	4.549%	-0.132%	-2.811%	5,961,973	100.00%		
2019	253,570	4.281%	-0.268%	-5.894%	5,923,221	100.00%		
2020	201,181	3.339%	-0.942%	-22.010%	6,025,668	100.00%		

Comparison of
Current Demand and Energy Loss Adjustment Factors
for Service Delivered at Transmission Voltage
Non-ERCOT IOUs

Energy Loss Adjustment Factors

Service Voltage	EPE	ETI	SWEPCO	SPS
Transmission 115 kV and Above		1.004965	1.014780	1.029633
Transmission at 69 kV	1.029160	1.022111	1.028820	1.035919

Demand Loss Adjustment Factors

Service Voltage	EPE	ETI	SWEPCO	SPS
Transmission 115 kV and Above		1.004022	1.018530	1.023667
Transmission at 69 kV	1.027900	1.017418	1.035360	1.030961

Difference Energy vs. Demand

Service Voltage	EPE	ETI	SWEPCO	SPS
Transmission 115 kV and Above		**0.000943**	-0.003750	**0.005966**
Transmission at 69 kV	**0.001260**	**0.004693**	-0.006540	**0.004958**

Comparison of
Current Demand and Energy Loss Factors
for All Service Delivery Voltages
Non-ERCOT IOUs

Energy Loss Adjustment Factors

Service Voltage	EPE	ETI	SWEPCO	SPS
Transmission 115 kV and Above		1.004965	1.014780	1.029633
Transmission at 69 kV	1.029160	1.022111	1.028820	1.035919
Primary Substation	1.034670		1.025150	
Primary Line	1.051230	1.048178	1.041030	1.105898
Secondary Transformer				1.125047
Secondary Line				1.128389
Secondary (Composite)	1.078500	1.075681	1.078560	1.126935

Demand Loss Adjustment Factors

Service Voltage	EPE	ETI	SWEPCO	SPS
Transmission 115 kV and Above		1.004022	1.018530	1.023667
Transmission at 69 kV	1.027900	1.017418	1.035360	1.030961
Primary Substation	1.031580		1.027130	
Primary Line	1.062650	1.060360	1.048820	1.131015
Secondary Transformer				1.161769
Secondary Line				1.166539
Secondary (Composite)	1.082120	1.081406	1.078720	1.164833

Ratio of Energy Loss Factors to Demand Loss by Voltage

Service Voltage	EPE	ETI	SWEPCO	SPS
Transmission 115 kV and Above		**123.45%**	79.76%	**125.21%**
Transmission at 69 kV	**104.52%**	**126.94%**	81.50%	**116.01%**
Primary Substation	**109.78%**		92.70%	
Primary Line	81.77%	79.82%	84.04%	80.83%
Secondary Transformer				77.30%
Secondary Line				77.09%
Secondary (Composite)	95.59%	92.97%	99.80%	77.01%

WORKPAPERS

PROVIDED

ELECTRONICALLY

The following files are not convertible:

Attachment EDE-1CR Comparison of
Customer Mix.xlsx
Attachment EDE-2CR Peak and Load Factor
Comp.xlsx
Attachment EDE-3CR EPE and SPS Peak
Load Comparison.xlsb
Attachment EDE-5CR and Wkps.xlsx
Attachment EDE-7CR Historical kWh
Analysis.xlsx
Attachments EDE-8CR and EDE-9CR
Losses.xlsx

Please see the ZIP file for this Filing on the PUC Interchange in order to access these files.

Contact centralrecords@puc.texas.gov if you have any questions.