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

DIRECT TESTIMONY

AND

WORKPAPERS

OF

EVAN D. EVANS

ON BEHALF OF THE

OFFICE OF PUBLIC UTILITY COUNSEL

COST ALLOCATION / RATE DESIGN PHASE

October 22, 2021

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DIRECT 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
AEP	American Electric Power Company
ALJ	Administrative Law Judge
AMS	Advanced Metering System
C&I	Commercial and Industrial
CEP	City of El Paso
CSW	Central and South West Corporation
EPE	El Paso Electric Company
FERC	Federal Energy Regulatory Commission
IOU	Investor-Owned Electric Utilities
kWh	Kilowatt-hour
MCD	Maximum Class Demand
MW	Megawatt
MWh	Megawatt-hour
NCP	Non-Coincident Peak
NMPRC	New Mexico Public Regulation Commission
OPUC	Office of Public Utility Counsel
O&M	Operations and Maintenance
PPA	Purchased Power Agreement

PUCT	Public Utility Commission of Texas
RFI	Request for Information
RFP	Rate Filing Package
ROE	Return on Equity
SOAH	State Office of Administrative Hearings
SPS	Southwestern Public Service Company
SWEPCO	Southwestern Electric Power Company

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. 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").

Q. PLEASE IDENTIFY BY WHOM YOU ARE EMPLOYED AND IN WHAT CAPACITY.

A. I am a principal and a consultant with Integrity Power Consulting, LLC. Integrity Power Consulting was established in 2003, and it provides consulting services to government agencies, and retail utility customers and customer groups. Integrity Power Consulting is also a registered electricity broker with the Public Utility Commission of Texas ("PUCT" or "Commission").

Q. PLEASE OUTLINE YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND.

A. I graduated from Texas Tech University with a Bachelor of Business Administration degree in Finance in May 1980.

Upon graduation, I was employed at West Texas Utilities Company, a wholly owned subsidiary of Central and South West Corporation ("CSW"), which was acquired by American Electric Power Company ("AEP") in June 2000. During my 20-year career with CSW and AEP, I held a variety of analytical, consultant, and management positions in the rates, regulatory services, load research, and marketing and business development areas.

In October 2000, I joined C.H. Guernsey & Company, now known as Guernsey Associates, which is an employee-owned consulting firm offering engineering, architectural, economic, and construction management services to utilities, industries, and government agencies throughout the United States and internationally. While employed with Guernsey, I managed the firm's Dallas regional office and provided consulting services to electric utility industry clients in a variety of areas, including regulatory compliance, integrated resource planning, electric utility cost of service issues, rate studies, financial analysis, economic feasibility analysis, retail electric choice, and wholesale power supply contract negotiations.

In September 2006, I left Guernsey and accepted the position of Director-Regulatory Services with El Paso Electric Company ("EPE" or "Company"). I was promoted to Assistant Vice President-Regulatory Services and Rates in July 2008. While at EPE, I established the company's Regulatory Case Management and Energy Efficiency & Utilization departments. My responsibilities included direction of EPE's Energy Efficiency & Utilization, Economic & Rate Research, Regulatory Case Management, and Regulatory Accounting departments and their associated missions.

In January 2014, I began my employment with Xcel Energy as Regional Vice President – Rates and Regulatory Affairs for Southwestern Public Service Company ("SPS"). In March 2017, I became Director – Regulatory and Pricing Analysis for SPS. My responsibilities included:

- developing and implementing SPS's regulatory program to ensure SPS fulfilled all legal and regulatory requirements of the PUCT, the New Mexico Public Regulation Commission ("NMPRC"), and the Federal Energy Regulatory Commission ("FERC");
- directing the development and execution of all regulatory case filings before state commissions and the FERC;
- leading regulatory activities to establish and maintain state and federal commission relationships and overseeing the administration of regulatory rules and procedures; and
- directing the cost allocation and pricing functions for SPS.

In October 2020, I left SPS and began working as a principal and consultant with Integrity Power Consulting.

Q. HAVE YOU TESTIFIED BEFORE THIS REGULATORY COMMISSION OR ANY OTHER REGULATORY AUTHORITIES?

A. Yes. I have testified in numerous cases or dockets and on a variety of subjects before the PUCT, the NMPRC, the Georgia Public Service Commission, and the Oklahoma Corporation Commission. I have also submitted testimony before the FERC. A list of prior cases in which I submitted testimony is provided in Attachment EDE-1.

II. PURPOSE AND SCOPE OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR RESPONSIVE TESTIMONY IN THIS PROCEEDING?

A. In this case, I will address the following issues with EPE's filed application:

- Jurisdictional cost allocation;
- Texas retail class cost allocation;
- Revenue increase distribution; and
- Rate design.

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

A. In this testimony, I recommend:

- Modification of the adjustments EPE made to its jurisdictional and Texas retail production demand allocation factors to reflect capacity supplied by dedicated company-owned solar facilities or solar Purchase Power Agreements ("PPAs") to adjust for EPE's planning reserve margin of 15%;
- EPE's entire demand-related production plant in service, including that associated with peaking units, should be allocated among jurisdictions and among Texas retail customer classes based on the Four Coincident Peak-Average and Excess ("4CP-A&E") allocation method;
- Correction of an error in the Production 12CP jurisdictional and Texas retail class allocation factors EPE used for the allocation of FERC Account No. 556 – System Control and Load Dispatching Expense;
- The energy consumed by interruptible loads should be included in the E1ENERGY allocator;
- The allocation of secondary lines, poles and fixtures, underground conduit and transformers should be allocated among Texas retail classes based on Maximum Class Demand ("MCD"), instead of Non-Coincident Peak ("NCP") demands;
- FERC Account No. 904 – Uncollectible Accounts Expense should be allocated on sales revenues among all Texas retail customer classes;
- Application of moderation to the distribution of the Texas jurisdictional base rate increase in this rate case such that no class is assigned a base rate increase that is more than 1.5 times the Texas retail average base rate increase, and no class is assigned an increase that is less than half the Texas retail average base rate increase;
- Not increasing the monthly customer charge for the Residential Service rate;

- Rejecting EPE's proposed modifications to reduce the summer months to four months, and to double the price differential between summer and non-summer months for Residential Service and Small General Service customers; and
- Rejecting EPE's proposal to double the price differential between the charges applied to the first and second summer energy blocks for Residential Service.

Q. IF YOU DO NOT ADDRESS AN ISSUE OR POSITION ON ANY ISSUE IN YOUR TESTIMONY, SHOULD THAT BE INTERPRETED AS SUPPORTING THE COMPANY'S POSITION ON THAT ISSUE?

A. No. Any cost or adjustment included in EPE's Rate Filing Package ("RFP"), application, or update to the application that is not addressed in my testimony does not indicate my acquiescence to EPE's proposed cost or adjustment.

III. JURISDICTIONAL COST ALLOCATION

Q. PLEASE IDENTIFY THE JURISDICTIONAL COST ALLOCATION ISSUES YOU WILL ADDRESS IN THIS SECTION OF YOUR TESTIMONY.

A. In this section, I will discuss the following:

- The need to modify EPE's adjustments to its jurisdictional production demand allocation factors to reflect capacity supplied by dedicated company-owned solar facilities or solar PPAs to reflect EPE's planning reserve margin of 15%;
- EPE's change to the load factor used in EPE's calculation of the 4CP-A&E allocator used to allocate production plant and related costs among jurisdictions;
- EPE's proposal to divide production plant into peaking and non-peaking plants for cost allocation purposes;

- An error in the Production 12 Coincident Peak ("12CP") jurisdictional allocation factors EPE used to allocate FERC Account No. 556 – System Control and Load Dispatching Expense among jurisdictions; and
- The illustrative results of the jurisdictional cost allocation study using accounting adjustments and capitalization provided by OPUC witness, Constance T. Cannady and EPE's requested ROE of 10.30%.

a. Solar Generation Capacity Adjustment to Jurisdictional Allocation Factors

Q. PLEASE DISCUSS THE ADJUSTMENTS EPE MADE TO ITS JURISDICTIONAL PRODUCTION DEMAND ALLOCATION FACTORS FOR DEDICATED SOLAR GENERATION.

A. EPE identified the generation from solar resources, both EPE-owned facilities and solar PPAs, that were built or acquired to serve a specific jurisdiction's customers.[1] EPE directly assigned the capacity and energy supplied to the relevant jurisdiction.[2] EPE then removed the capacity and energy supplied by these resources from the retail customers energy and production demands used in the jurisdictional allocators.[3]

Q. PLEASE EXPLAIN THE MODIFICATION YOU PROPOSE TO EPE'S JURISDICTIONAL DEMAND ALLOCATION FACTORS.

A. In EPE's adjustment to its jurisdictional and class demand allocation factors for the capacity supplied by these dedicated solar resources, it failed to account for the fact that EPE maintains a15% planning reserve requirement.[4] This planning reserve requirement

[1] Direct Testimony of George Novela at 7:15-18.

[2] *Id.* at 7:19-21

[3] *Id.* at 7:13-28.

[4] Direct Testimony of David C. Hawkins, Exhibit DCH-2, page 1.

means that EPE's capacity planning policy requires EPE to plan its future capacity to ensure that it maintains sufficient capacity to serve EPE's firm load plus 15% planning reserves. Therefore, the capacity adjustment for dedicated solar resources to jurisdictional demand allocation factors should be divided by 1.15 to correctly account for planning reserve requirements. Attachment EDE-2 provides a comparison of the jurisdictional 4CP-A&E, 4CP and 12CP production demand allocators under EPE's filed calculation and those same allocators after the calculations have been corrected to reflect the impact of EPE's 15% planning reserve margin on the dedicated solar resource adjustment.

Q. WHAT IS A PLANNING RESERVE MARGIN?

A. In Docket No. 50277[5], Mr. Omar Gallegos filed testimony on behalf of EPE and provided EPE's definition. In his direct testimony he stated:

> "A reserve margin is that amount of firm resources above the projected peak load required to sustain overall system reliability in excess of projected annual firm demand, given the utility's obligation to serve. Utilities must maintain a positive reserve margin to help ensure service can continue upon the occurrence of events such as forced outages during peak times and unexpected increases in demand often due to extremely hot summer conditions. The minimum amount of planning reserves is determined by the utility's reserve margin criteria."[6]

Q. WHAT IS YOUR RECOMMENDATION RELATED TO THE MODIFICATION OF THE SOLAR GENERATION CAPACITY ADJUSTMENT FOR PLANNING RESERVES?

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[5] *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 (Nov. 22, 2019).

[6] Docket No. 50277, Direct Testimony of Omar Gallegos at 8:27 – 9:2.

A. I recommend the 4CP-A&E, 12CP and all other production demand allocators used to allocate EPE's production demand costs reflect the 15% planning reserve modification to the solar generation capacity adjustment. These corrected jurisdictional allocators are shown on Attachment EDE-2.

b. EPE's Change to the Calculation of the 4CP-A&E Allocator

Q. WHAT CHANGE IS EPE PROPOSING TO THE CALCULATION OF ITS 4CP-A&E ALLOCATOR?

A. EPE made one significant change to the calculation of its 4CP-A&E allocator that differs from the methodology EPE used in its last base rate case, Docket No. 46831.[7] EPE changed the load factor used in the calculation of the 4 Coincident Peak-Average and Excess allocators from a load factor calculated using a single highest coincident peak load ("1CP") to use a load factor based on the four peak months (June-September).[8] EPE stated this modification will make the calculation consistent with the calculation of the 4CP-A&E allocator for EPE's regulatory filings in its New Mexico Jurisdiction.[9] In addition, this approach is consistent with the calculations EPE used in their filed Texas rate cases prior to their last rate case, Docket No. 46831.[10]

Q. WHAT REASON DID EPE PROVIDE FOR MAKING THE CHANGE TO THE CALCULATION?

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[7] *Application of El Paso Electric Company to Change Rates,* Docket No. 46831 (Feb. 3, 20217).

[8] Direct Testimony of George Novela at 7:30 – 8:12.

[9] *Ibid.*

[10] *Id.* at 8:14 – 9:3.

A. In his direct testimony discussing this issue, EPE Witness Mr. George Novela argued that use of a 1CP load factor in the calculation of the 4CP-A&E allocation factor instead of the average of the 4CP months peaks is not consistent with the purpose of the allocation factor.[11] He also discussed that the system load factor employed to derive the proportions of average demand versus peak demand should be consistent with the associated allocation.[12] Mr. Novela also argued that since the 4CP demand is used to calculate the "excess demand," the same 4CP demand should be employed to calculate system annual load factor. In addition, Mr. Novela states that using 4CP avoids any anomaly that could result from an unexpectedly high single peak hour.[13]

Q. DO YOU AGREE WITH EPE'S PROPOSED MODIFICATION TO THE CALCULATION OF ITS 4CP-A&E PRODUCTION ALLOCATOR?

A. Yes, I agree with EPE. The use of a 1CP to calculate the load factor is inconsistent with the use of 4CP demands in the 4CP-A&E. It also unreasonably reduces the impact of the average demand, or "energy" component of this allocation method and unreasonably increases the portion of costs allocated based upon excess demands. Attachment EDE-3 contains a comparison of EPE's proposed method for calculating the 4CP-A&E to a 4CP-A&E calculated using a 1CP load factor and to a simple 4CP production allocator, which does not have any average demand or energy component. This comparison shows that the use of a 1CP load factor causes the allocation to the Texas retail jurisdiction to be 0.19% greater than using EPE's 4CP load factor-based calculation for the 4CP-A&E. It also

[11] *Id.* at 9:6 – 8.

[12] *Id.* at 9:9 – 11.

[13] *Id.* at 9:11 – 15.

shows that a 1CP load factor-based 4CP-A&E also allocates 0.22% more production costs to the Texas retail jurisdiction than a straight 4CP production allocator. Therefore, using EPE's proposed modification causes less production costs to be allocated to the Texas retail jurisdiction.

c. Dividing Production Plant into Peaking and Non-Peaking Plant for Cost Allocation

Q. WHAT IS EPE'S PROPOSAL CONCERNING DIVIDING PRODUCTION PLANT INTO PEAKING AND NON-PEAKING PLANT FOR COST ALLOCATION PURPOSES?

A. EPE is proposing to divide its production plant into non-peaking and peaking plant for cost allocation purposes.[14] EPE proposes to use the 4CP-A&E methodology for allocating jurisdictional demand-related expenses of non-peaking generation facilities and to use a straight 4CP methodology for allocating jurisdictional demand-related costs of peaking generation facilities.[15] This is the first rate case in which EPE split its production plant into peaking and non-peaking facilities and allocated the two pieces among jurisdictions on two different allocation methods. In previous rate cases EPE allocated all demand-related production costs among its jurisdictions based on the 4CP-A&E method.[16]

Q. WHAT IS THE BASIS FOR EPE'S PROPOSAL TO SPLIT ITS PRODUCTION PLANTS INTO PEAKING AND NON-PEAKING PLANTS FOR COST ALLOCATION PURPOSES?

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[14] Direct Testimony of Adrian Hernandez at 9:21-26.

[15] *Ibid.*

[16] *Id.* at 10:12 – 17.

A. EPE's cost allocation witness, Mr. Adrian Hernandez, stated in his direct testimony:

> "EPE's generation facilities are a mix of non-peaking 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."[17]

Q. WHICH GENERATION FACILITIES DID EPE IDENTIFY AS PEAKING UNITS?

A. Mr. Hernandez identified the following generation facilities as peaking units:

- Montana Power Station Units 1 through 4;
- Rio Grande Generating Station Unit 9; and
- Copper Generating Station.[18]

Q. DOES THE DATA FILED BY EPE IN THIS CASE SUPPORT MR. HERNANDEZ'S TESTIMONY?

A. No. Schedules H-12-2b and H-12.2b1 provide the monthly generation for each of EPE's natural gas-fired generating units for 2020 and the five previous calendar years. Those schedules reveal that each of the six units generated a significant amount of energy during the eight non-summer months for 2020 and previous years. Attachment EDE-4 identifies the percentage of annual MWh generated by unit during the non-summer months and the summer months for the calendar years of 2017 through 2020. The data provided in Schedules H-12-2b and H-12-2b1 and in Attachment EDE-4 contradicts the statements made in Mr. Hernandez's testimony.

[17] Direct Testimony of Adrian Hernandez at 10:19-31.

[18] *Id.* at 11:2-8.

Q. DOES THE HISTORICAL GENERATING DATA FILED BY EPE IN THIS CASE SUPPORT ALLOCATING THE INVESTMENT IN "PEAKING PLANTS" BETWEEN JURISDICTIONS DIFFERENTLY FROM THE OTHER EPE GENERATING PLANT?

A. No. The six units that EPE identified as peaking plants generate a substantial amount of energy during all months of the year and not just during the peak hours of the four summer months. Therefore, it is not appropriate to allocate the costs for the six units on the 4CP in EPE's jurisdictional cost allocation. All production demand-related investment and associated expenses should be allocated among jurisdictions based on the same, 4CP-A&E method.

Q. WHAT IS YOUR RECOMMENDATION CONCERNING THE DIVISION OF EPE'S PRODUCTION PLANT INTO PEAKING AND NON-PEAKING UNITS FOR JURISDICTIONAL COST ALLOCATION PURPOSES?

A. I recommend EPE's production plant not be divided into peaking and non-peaking plants for production demand cost allocation. I recommend that all of EPE's production plant be allocated among jurisdictions based upon the 4CP-A&E production demand allocator.

d. Error in EPE's Production 12CP Jurisdictional Allocator

Q. PLEASE DESCRIBE THE ERROR IN EPE'S PRODUCTION 12CP ALLOCATOR?

A. In Mr. Hernandez's testimony, he stated that the allocator "DPROD12" in the jurisdictional cost of service model was a 12CP allocator and it was used to allocate system control and dispatch expenses.[19] However, DPROD12 does not reflect EPE's 12CP demands. Based on a review of the EPE Regulatory Case Working Model ("EPE Working Model") provided by EPE in their filing and Attachment 2 to EPE's response to the City of El Paso's ("CEP") Fourth Request for Information (RFI) No. 4-6, it appears EPE inadvertently used information from a column entitled "12CP-A&E" instead of 12CP for the allocator DPROD12. The Texas jurisdictional allocation shown in the "Allocation Factor" tab of the EPE Working Model indicates the DRPOD12 allocates 81.536% of costs to the Texas retail jurisdiction. However, Attachment 2 to the response to CEP RFI No. 4-6 indicates that only 80.6165%, or 0.92% less should be allocated to the Texas retail jurisdiction, based upon EPE's filed allocators.

Q. WHAT IS YOUR RECOMMENDATION ON THIS ISSUE?

A. I recommend the DPROD12 allocator be corrected to reflect the 12CP jurisdictional demands. The 12CP jurisdictional demands should also be modified to reflect the 15% planning reserve adjustment to jurisdictionally dedicated solar resources that I discussed previously.

IV. TEXAS RETAIL CLASS COST ALLOCATION ISSUES

Q. WHAT ISSUES WILL YOU DISCUSS RELATED TO EPE'S ALLOCATION OF COSTS AMONG THE TEXAS RETAIL CUSTOMER CLASSES?

A. In this section, I will discuss the following:

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[19] *Id.* at 13:5 – 14.

- The modification of EPE's adjustments to its Texas retail class production demand allocation factors to reflect capacity supplied by dedicated company-owned solar facilities or solar PPA to adjust for EPE's planning reserve margin of 15%;
- EPE's change to the load factor used in EPE's calculation of the 4CP-A&E allocator used to allocate production plant and related costs;
- EPE's proposal to divide production plant into peaking and non-peaking plants for cost allocation purposes;
- An error in EPE's Production 12CP Texas retail allocation factors the Company used to allocate FERC Account No. 556 – System Control and Load Dispatching Expense among jurisdictions;
- The exclusion of energy consumption for interruptible loads in the E1Energy allocator;
- The allocation of secondary distribution lines and transformers on NCP demands; and
- The allocation of Account 904 – Uncollectible Accounts Expense among customer classes.

a. Solar Generation Capacity Adjustment to Production Allocation Factors

Q. PLEASE DISCUSS THE ADJUSTMENTS EPE MADE TO ITS TEXAS RETAIL CLASS PRODUCTION DEMAND ALLOCATION FACTORS FOR DEDICATED SOLAR GENERATION.

A. As I discussed in the Jurisdictional Cost Allocation section of this testimony, EPE identified the generation from solar resources, both EPE-owned facilities and solar PPAs, that were built or acquired to serve a specific jurisdiction's customers. EPE directly assigned the capacity and energy supplied to the relevant jurisdiction. EPE then removed the capacity and energy supplied by these resources from the retail customers energy and production demands used in the jurisdictional allocators.

Q. ARE YOU PROPOSING A COMPARABLE ADJUSTMENT TO EPE'S TEXAS RETAIL CLASS PRODUCTION DEMAND ALLOCATION FACTORS AS YOU DID TO EPE'S JURISDICTIONAL DEMAND ALLOCATION FACTORS?

A. Yes. Consistent with the modification to the jurisdictional production demand allocation factors, the adjustment to customer class production demand allocation factors for the dedicated solar resources should be adjusted to reflect EPE's 15% planning reserve requirement. Attachment EDE-6 provides a comparison of the 4CP-A&E, 4CP and 12CP production demand allocators by customer class and jurisdiction under EPE's filed calculation and those same allocators after the calculations have been corrected to reflect the impact of EPE's 15% planning reserve margin on the dedicated solar resources adjustment. Attachment EDE-6 also provides my recommended 4CP-A&E, 4CP and 12CP production demand allocation factors by jurisdiction and by Texas retail customer class.

b. EPE's Change to the Calculation of the 4CP-A&E Allocator

Q. IS EPE'S PROPOSED CHANGE TO THE CALCULATION OF ITS 4CP-A&E ALLOCATOR FOR THE CLASS COST ALLOCATION STUDY CONSISTENT WITH THE CHANGE IT PROPOSED FOR THE JURISDICTIONAL COST STUDY?

A. Yes, it is. EPE proposes to change the load factor used in the calculation of the 4 Coincident Peak-Average and Excess allocators from a load factor calculated using a single highest coincident peak load to use a load factor based on the four peak months (June-

September). This approach is consistent with the calculations EPE used in their filed Texas rate cases prior to their last rate case, Docket No. 46831.[20]

Q. WHAT REASON DID EPE PROVIDE FOR MAKING THE CHANGE TO THE CALCULATION?

A. In his direct testimony discussing this issue, EPE Witness Mr. Novela argued that use of a 1CP load factor in the calculation of the 4CP-A&E allocation factor instead of the average of the 4CP months peaks is not consistent with the purpose of the allocation factor[21]. He also discussed that the system load factor employed to derive the proportions of average demand versus peak demand should be consistent with the associated allocation[22]. Since the 4CP demand is used to calculate the "excess demand," the same 4CP demand should be employed to calculate system annual load factor. In addition, using 4CP avoids any anomaly that could result from an unexpectedly high single peak hour.[23]

Q. DO YOU AGREE WITH EPE'S PROPOSED MODIFICATION TO THE CALCULATION OF ITS 4CP-A&E PRODUCTION ALLOCATOR FOR ITS CLASS COST ALLOCATION STUDY?

A. Yes, I agree with EPE. The use of four coincident peaks to calculate the load factor is consistent with the use of 4CP demands in the 4CP-A&E. In addition, the use of a 1CP to calculate the load factor unreasonably reduces the impact of the average demand, or "energy" component of the customer classes and unreasonably increases the portion of

[20] *Id.* at 8:14 – 9:3.

[21] *Id.* at 9:6-8.

[22] *Id.* at 9:9 – 11.

[23] *Id.* at 9:5 – 14.

costs allocated among customer classes based upon peak or excess demands. I recommend this proposed modification to calculation of the 4CP-A&E production allocation be approved.

c. Dividing Production Plant into Peaking and Non-Peaking Plant for Cost Allocation

Q. IS EPE PROPOSING TO DIVIDE PRODUCTION PLANT INTO PEAKING AND NON-PEAKING PLANT FOR CLASS COST ALLOCATION PURPOSES CONSISTENT WITH THEIR PROPOSAL FOR JURISDICTIONAL COST ALLOCATION?

A. Yes. EPE is proposing to divide its production plant into non-peaking and peaking plant for customer class cost allocation purposes, consistent with their proposal for jurisdictional cost allocation purposes. EPE proposes to use the 4CP-A&E methodology for allocating jurisdictional demand related expenses of non-peaking generation facilities and to use a straight 4CP methodology for allocating jurisdictional demand-related costs of peaking generation facilities. As I discussed in the Jurisdictional Cost Allocation section of this testimony, the data provided in EPE's filed Schedules H-12-2b and H-12-2b1 contradicts Mr. Hernandez's assertion that the units he identified as peaking generating facilities are not expected to operate during native system off-peak times.[24] Attachment EDE-4 identifies the percentage of annual MWh generated by unit during the non-summer months and the summer months for the calendar years of 2017 through 2020 based on data provided in Schedules H-12-2b and H-12-2b1. This data clearly shows that the units that Mr.

[24] *Id.* at 10:19 - 31.

Hernandez identified as peaking units generate a substantial amount of MWh during the non-summer months.

Q. WHAT IS YOUR RECOMMENDATION CONCERNING THIS ISSUE?

A. I recommend EPE's production plant not be divided into peaking and non-peaking plants for production demand cost allocation. I recommend that all of EPE's production plant be allocated among Texas retail customer classes based upon the 4CP-A&E production demand allocator.

d. Error in EPE's Production 12CP Allocator

Q. DID EPE MAKE THE SAME ERROR IN ITS PRODUCTION 12CP ALLOCATOR IN THE CUSTOMER CLASS COST STUDY AS IT DID IN THE JURISDICTIONAL COST STUDY?

A. Yes. DPROD12 does not reflect EPE's 12CP demands. Based on a review of the EPE Regulatory Case Working Model ("EPE Working Model") provided by EPE in their filing and Attachment 2 to EPE's response to the CEP RFI No. 4-6, it appears EPE inadvertently used information from a column entitled "12CP-A&E" instead of 12CP for the allocator DPROD12. In his testimony, Mr. Hernandez identified the DPROD12 allocator as a 12CP allocator.[25]

Q. WHAT IS YOUR RECOMMENDATION ON THIS ISSUE?

A. I recommend the DPROD12 allocator be corrected to reflect the 12CP allocation. The 12CP allocator by customer class is shown in Attachment EDE-6.

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[25] *Id.* at 23:29.

e. Exclusion of Energy Sales to Interruptible Loads in E1ENERGY Allocator

Q. DISCUSS THE ISSUE SURROUNDING THE EXCLUSION OF ENERGY SALES TO INTERRUPTIBLE LOADS FROM THE E1ENERGY ALLOCATOR.

A. Mr. Hernandez stated in his direct testimony that "EPE witness Novela develops the E1ENERGY allocator using kWh at supply excluding non-firm (interruptible) kWh."[26] In addition, in response to the CEP RFI No. 9-28, which is provided as Attachment EDE-7 to this testimony, Mr. Hernandez explained his justification for excluding the interruptible kWh from the E1ENERGY allocator. Mr. Hernandez stated:

> "The E1ENERGY allocator is used to allocate energy-related generation operation and maintenance ("O&M") expenses in the cost of service. Since the results of these allocations in the cost of service are used to determine EPE's firm base rates, then non-firm kWh should not be included in allocating O&M production expenses. Therefore, just like non-interruptible customers, interruptible customers receive the same treatment by using only their firm kWh in determining the production O&M costs included in their firm base rates." [27]

Q. IS MR. HERNANDEZ'S JUSTIFICATION FOR EXCLUDING INTERRUPTIBLE kWh FROM E1ENERGY REASONABLE?

A. No, it is not. Mr. Hernandez's approach shifts the responsibility for non-fuel, energy-related generation O&M entirely onto firm customers and causes Residential Service and other firm customers to subsidize the interruptible sales. The non-fuel, energy-related generation O&M costs are associated with operating and maintaining EPE's generation

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[26] *Id.* at 14:1-2.

[27] El Paso Electric Company's Response to CEP's Ninth Request for Information, Question CEP 9-28.

resources that serve both firm and interruptible load. It is not appropriate to force firm customers to bear the entirety of these costs.

Q. WHAT IS YOUR RECOMMENDATION TO CORRECT THIS ISSUE?

A. I recommend that the energy charge for interruptible service be increased to reflect the portion of these generation O&M expenses and all other associated costs that would be allocated to the interruptible energy if they were treated as a separate class. In addition, the associated incremental interruptible revenue should be credited to firm customers and allocated based upon the E1ENERGY allocator.

An alternative approach would be to simply assign the interruptible energy to the customer classes under which the interruptible customers receive firm service. This alternative approach would protect customer classes that only have firm service customers from subsidizing the energy-related costs of interruptible loads. However, it would cause firm customers in those classes to bear a portion of the energy-related costs associated with the customers whose firm service is reflected in those classes, but also have interruptible loads.

f. Allocation of Secondary Lines and Transformers on NCP Demands

Q. PLEASE DESCRIBE THE ISSUE RELATED TO THE ALLOCATION OF SECONDARY LINES AND TRANSFORMERS.

A. EPE proposes to allocate the investment in secondary overhead and underground lines and secondary line transformers based on the annual NCP demands for each customer class.[28]

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[28] Direct Testimony of Adrian Hernandez at 20:24-28.

This affects the portion of the following FERC Distribution Plant Accounts that provide service at secondary voltages:

- 364 – Poles, Towers and Fixtures;
- 365 - Overhead Conductor and Devices;
- 366 - Underground Conduit;
- 367 – Underground Conductors and Devices; and
- 368 Line Transformers.

Q. WHAT ARE NCP DEMANDS?

A. NCP represents the summation of the maximum loads of each customer within a rate class, independent of the class peak or system peak. As a result, the NCP is the sum of maximum demand of each customer within a class, without respect to when it occurs. An NCP demand allocator assumes that for each customer class, every customer's peak demand occurs at the exact same time, even though it did not occur. It is virtually impossible that all customers would ever peak at the same time for most customer classes that have more than a few customers.

Q. WHAT JUSTIFICATION DID EPE STATE FOR THEIR PROPOSAL?

A. In his filed testimony in this case, Mr. Hernandez's only statement supporting the use of the NCP demand allocation method for secondary lines and line transformers was, "This method allocates costs to serve customers based on their diversity at the more localized secondary distribution system." [29] However, Mr. Hernandez's statement is contradicted by the fact that an NCP demand allocator assumes that each customer's maximum demand

[29] *Id.* at 21:12 – 14.

occurs at the same time and ignores the fact that they actually occur at diverse times throughout the month.

Q. DO ELECTRIC UTILITIES TYPICALLY PLAN AND DESIGN SECONDARY DISTRIBUTION FACILITIES ASSUMING THAT EVERY CUSTOMER'S MAXIMUM DEMAND OCCURS AT THE SAME TIME?

A. No. Electric utility distribution planners design secondary distribution facilities that serve multiple customers based on the knowledge that customers' maximum demands occur at diverse times. Therefore, the total peak load of secondary facilities that serve multiple customers are typically sized to serve less than the sum of the maximum demands for each customer that is served by those facilities.

This is as true for EPE's distribution planners as it is for all other electric utilities. Attachment EDE-8 contains EPE's response to OPUC's RFI No. 5-10 from Docket No. 44941.[30] This response contains documents that describe how EPE incorporates the fact that customers served by secondary lines and line transformers have maximum demands that occur at diverse times. Therefore, EPE plans and designs its secondary lines and transformers that serve multiple customers expecting that the peak demand on those facilities will be less than the sum of the maximum demands for the customers served by those facilities. This is clearly reflected in the Diversified Demand Chart for Residences provided on page 2 of Attachment EDE-8. This chart indicates that EPE plans its distribution assuming approximately a 40% reduction from the summed NCP demands for residences if 5 customers are served from a secondary line or transformer, approximately

[30] *Application of El Paso Electric Company to Change Rates,* Docket No. 44941 (Aug. 10, 2015).

a 50% reduction if 10 customers are served, and approximately a 60% reduction if 15 customers are served from a secondary line or transformer.

Q. HAVE YOU ANALYZED THE DIVERSITY OF DEMANDS FOR SECONDARY VOLTAGE CUSTOMERS BASED ON INFORMATION FILED BY EPE IN THIS DOCKET?

A. Yes. Attachment EDE-9 contains a comparison of MCD, NCP, and the MCD to NCP diversity factor for each secondary voltage customer class. Attachment EDE-9 reveals that Residential Service has a 174.46% MCD to NCP diversity factor and Water Heating Service has a 224.68% diversity factor, both of which are significantly higher than the average of 155.51%.

Q. WHAT ALLOCATION METHOD DO THE OTHER THREE FULLY-INTEGRATED ELECTRIC UTILITIES IN TEXAS USE TO ALLOCATE SECONDARY LINES AND TRANSFORMERS?

A. All three of the other fully-integrated electric utilities in Texas use MCD to allocate secondary lines and transformers to some extent. In their current rate cases, Docket Nos. 51415 and 51802, Southwestern Electric Power Company ('SWEPCO")[31] and SPS,[32] respectively, use the equivalent of MCD to allocate secondary lines and transformers. The use of MCD demands to allocate secondary lines and transformers is not a disputed issue in either of their current rate cases and they have used MCD to allocate this investment in their previous rate cases. In Entergy Texas's most recent base rate case, Docket No. 48371,

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[31] Direct Testimony of John O. Aaron at 18:15 – 23 (Docket No. 51415).

[32] Direct Testimony of Richard M. Luth at 40:16 – 41:6 (Docket No. 51802).

they used a cost allocation method based on 50% MCD and 50% NCP demands to allocate secondary lines and transformers.[33]

Q. WHAT ALLOCATION METHOD WOULD MORE ACCURATELY REFLECT THE DIVERSITY IN CUSTOMER MAXIMUM DEMANDS THAT EPE'S DISTRIBUTION PLANNERS CONSIDER IN THEIR PLANNING AND DESIGN OF SECONDARY DISTRIBUTION FACILITIES?

A. The MCD allocation method would more accurately reflect the diversity in maximum demands considered by EPE's distribution planners when they are planning and designing the secondary distribution system. Due to the fundamental principle that the allocation of costs should follow cost causation, the allocation of secondary distribution facilities on MCD-based allocators matches the factors that are considered when those facilities are constructed and placed into service. Therefore, I recommend that secondary lines, line transformers, and associated costs be allocated among customer classes that are served at secondary voltages based upon MCD-based demand allocators instead of EPE's proposal to allocate using NCP-based demand allocators.

g. Allocation of Uncollectible Accounts Expense

Q. PLEASE DISCUSS EPE'S PROPOSED ALLOCATION OF FERC ACCOUNT NO. 904 - UNCOLLECTIBLE ACCOUNTS EXPENSE.

A. In this case, EPE is proposing to allocate Account 904 - Uncollectible Accounts Expense, to some but not all Texas retail classes based upon present sales revenues for those

[33] Direct Testimony of R. Phillip Griffin at 16:17 – 27 (Docket No. 48371).

classes.[34] Mr. Hernandez states, "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 Commercial and Industrial ("C&I") Large customers."[35] This is a change from the EPE's allocation of the Uncollectible Accounts Expense in Docket No. 46831, EPE's last base rate case. In that case, EPE only proposed to exclude governmental customers.[36]

Q. WHAT JUSTIFICATION DID MR. HERNANDEZ PROVIDE FOR USING THIS ALLOCATION METHOD?

A. Mr. Hernandez stated, "EPE's allocation of uncollectible expense takes guidance from the Company's accounts receivable aging schedule to estimate bad debts. EPE recently changed their policy to exclude C&I Large customers from the aging schedule. Therefore, EPE's allocation of uncollectible expense will exclude both Other Public Authority and C&I Large customers."[37]

Q. DO YOU AGREE WITH EPE'S PROPOSED METHOD FOR ALLOCATING UNCOLLECTIBLE ACCOUNTS EXPENSE?

A. No. These Uncollectible Accounts costs cannot be specifically associated with any group of paying customers. These are cost associated with customers who are no longer known to be served by EPE. Therefore, it is not appropriate to allocate the costs associated with customers who are no longer EPE customers specifically to the paying customers in the

[34] Direct Testimony of Adrian Hernandez at 15:10 – 13.

[35] *Id.* at 24:28-31.

[36] *Id.* at 15:15 – 21.

[37] *Ibid.* at 15:15-21.

classes under which they were formerly served. These costs are no more the responsibility of the paying customers in their former rate classes than it is customers in any other rate classes. Therefore, these costs should be considered as system costs and be recovered from all customer classes in proportion to sales revenues.

Q. HAS THE COMMISSION ADDRESSED THE ALLOCATION OF UNCOLLECTIBLE ACCOUNTS EXPENSE IN OTHER RATE CASES?

A. Yes. The Commission specifically addressed this issue in SPS's 2015 rate case, Docket No. 43695. Finding of Facts 310 and 311 of the Commission's Order on Rehearing in Docket No. 43695 directly addressed this issue. Those Finding of Facts state:

> 310. SPS reasonably allocated Uncollectible Account expense in FERC Account 904 on the basis of present base rate sales by class.
>
> 311. Uncollectible expenses are caused by non-paying customers, and the current customers in a particular class are not the cause of uncollectible expense created by other members of that class.[38]

Q. WHAT IS YOUR RECOMMENDATION?

A. I recommend EPE's proposed change be rejected in favor of allocating the Uncollectible Accounts Expense to all Texas retail customer classes based on sales revenues, which is consistent with the Commission's clearly stated precedent. EPE has not provided any reasonable justification for its proposed change, and EPE cannot support their allocation of these costs to all rate classes, except Other Public Authority and C&I Large customer classes.

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[38] *Application of Southwestern Public Service Company for Authority to Change Rates*, Docket No. 43695, Order on Rehearing at FOF Nos. 310 and 311 (Feb. 23, 2016).

V. REVENUE INCREASE DISTRIBUTION

Q. WHAT CONCERNS ARE YOU ADDRESSING RELATIVE TO REVENUE INCREASE DISTRIBUTION?

A. In this section, I encourage the Commission to incorporate moderation in the movement of customer classes to equal rates of return as base rate increases are assigned to customer classes. The test-year, calendar year 2020, was an unusual year. The pandemic significantly impacted EPE's loads and the usage characteristics of customer classes in diverse ways.

Q. WHAT IS EPE'S PROPOSAL FOR THE DISTRIBUTION OF THE REVENUE INCREASE AMONG CUSTOMER CLASSES?

A. EPE proposed to modify the cost-based revenue requirements for the Residential Service, Water Heating, Small General Service, General Service, and City/County rate groups[39]. EPE proposed to initially cap the allocated base revenue increase for the Residential and Water Heating classes at 1.5 times the system average increase of 7.38%, or 11.07%[40]. EPE also proposed to limit the base revenue reductions for the Small General Service, General Service, and the City/County rate groups to 50% of the cost-based reduction from EPE's class cost of service at equalized rates of return.[41] The remaining amount of the

[39] Direct Testimony of James Schichtl at 38:30 – 39:4.

[40] Direct Testimony of Manny Carrasco at 14:12 – 19.

[41] *Id.* at 14:25 – 26.

revenue deficiency that is not recovered with these limits is then redistributed to all rate groups, including the moderated groups.[42]

Q. WHAT RATIONALE DOES EPE PROVIDE FOR MODERATING THE REVENUE INCREASE DISTRIBUTION IN THE MANNER THEY PROPOSED?

A. In the Direct Testimony of EPE witness Mr. James Shichtl, he states:

> "While EPE's preferred revenue allocation in this case is full cost of service, the rate moderation proposed here reflects primarily the class sales uncertainty created by the COVID 19 pandemic in 2020. The "moderated" classes in EPE's proposal are those which show the most variation in 2020 as a direct result of the pandemic and are likewise the most likely to see changes in 2022 as conditions return to some degree of pre-pandemic levels. EPE witness Novela discusses the observed sales impacts in his testimony. These changes during 2020 impact the allocation factors employed by EPE witness Hernandez in the class cost of service analysis and, as he notes, result in some significant reallocation of costs between rate classes unlike studies from previous rate cases."[43]

Q. DO YOU AGREE WITH EPE'S PROPOSED REVENUE DISTRIBUTION?

A. No. I agree with their underlying principle of moderating the base revenue increases due to the impact of COVID-19 on load characteristics for customer classes during the historical test-year of 2020 and the uncertainty of sales by customer class created by the COVID-19 pandemic. However, I do not believe moderation of significant rate changes should be limited to only a few customer classes. Also, any under-recovered amounts from the initial application of the revenue increase maximum and minimums in the revenue distribution should not cause classes that have been assigned the maximum percentage base rate increase to exceed the established maximum base revenue increase percentage.

[42] Direct Testimony of James Schichtl at 38:28 – 39:7.

[43] *Id.* at 39:9-21.

Likewise, any over-recovered amounts that result from the initial application of the revenue increase maximum and minimums in the revenue distribution should not cause classes that have been assigned the minimum percentage base rate increase to drop below the established minimum base revenue increase percentage.

Q. DO YOU AGREE WITH EPE'S ASSUMPTION THAT THE IMPACTS OF THE PANDEMIC ONLY AFFECTED A FEW CUSTOMER CLASSES?

A. No, I do not agree. In addition, Mr. Novela stated, "The COVID-19 pandemic resulted in a shift in usage patterns over the test year due to business and government office closures and employees working from home as opposed to the office. This phenomena (sic) drove significant increased usage from residential customers and a significant reduction in usage from the commercial and city/county customers."[44] These significant changes in usage patterns and usage levels will have a comparable impact on demand and energy allocators, which will impact all customer classes.

Q. HAVE YOU COMPARED THE TEST-YEAR USAGE LEVELS FOR THE CUSTOMER CLASSES TO THE USAGE LEVELS FROM PREVIOUS YEARS?

A. Yes. Attachment EDE-13 provides a comparison of the actual usage per customer, by customer groups for 2020 to the usage per customer for those same groups during the most recent five years of 2015 through 2019. This comparison clearly shows that only the Residential Service and the Military Reservation Service classes experienced reduced kWh per customer during 2020 compared to the five-year average and compared to 2019. The Residential Service class experienced an 11.59% increase over the five-year average and

[44] Direct Testimony of George Novela at 10:7-13.

Military Reservation Service experienced a 4.82% increase over the five-year average. Although the information is not available, it would be expected that 4CP demands, 12CP and MCD demands would also be higher for those classes, particularly the Residential Service class. In contrast, the Total Texas Retail jurisdiction experienced a 2.35% decline from the five-year average.

Q. DID EPE ADJUST CUSTOMER CLASS USAGE LEVELS TO NORMALIZE FOR THE IMPACT OF THE PANDEMIC?

A. No. Mr. Novela stated in his testimony that EPE did not make any adjustments to its allocator methodology to account for any shifts in usage patterns.[45] Also, in response to OPUC RFI No. 1-4, Mr. Novela stated, "However, EPE did not make any adjustments to test-year sales to normalize the impact of the COVID-19 pandemic."[46]

Q. WHAT IS YOUR RECOMMENDATION CONCERNING THE BASE REVENUE INCREASE DISTRIBUTION AMONG CUSTOMER CLASSES?

A. I recommend the base revenue increase distribution among customer classes reflect moderation. The moderated increases for rate classes should include a firm maximum percentage increase and a firm minimum increase by rate class. Since EPE is requesting a significant base rate increase, I do not recommend that any firm service rate class be assigned a base rate decrease. I recommend the revenue decreases be developed so that no firm service rate class be assigned an increase that is more than 150% of the Texas retail

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[45] *Id.* at 10:14-16.

[46] EPE's Response to OPUC's First Request for Information, Question OPUC 1-4.

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.

Q. DO YOU BELIEVE THIS MODERATION APPROACH IS CONSISTENT WITH HISTORIC PRECEDENT?

A. Yes. In the past, the Commission has approved similar revenue distribution gradualism approaches in several settled and litigated base rate cases for fully integrated electric utilities.[47]

VI. RATE DESIGN ISSUES

Q. WHAT RATE DESIGN ISSUES WILL YOU ADDRESS IN THIS SECTION?

A. In this section, I will focus on EPE's proposed rate design changes affecting:

- Schedule 01 – Residential Service, including Off-Peak Water Heating Service Rider; and,
- Schedule 02 – Small General Service, including Off-Peak Water Heating Service.

a. Schedule 01 – Residential Service

Q. WHAT ISSUES WILL YOU ADDRESS RELATIVE TO THE RESIDENTIAL SERVICE RATE?

A. I will address EPE's following proposals that impact the standard Residential Service Rate and the Off-Peak Water Heating Service rate:

[47] Docket No. 40443, Order on Rehearing, FOF Nos. 287-290 (March 6, 2014) and Docket No. 46449, Order on Rehearing, FOF No. 314 (March 19, 2018).

- set the monthly Customer Charge to collect all the customer-related costs by increasing the charge from $8.25 per month to $10.54 per month;[48]
- shorten the summer season from six months (May through October) to four months (June through September);[49]
- double the current price differential between summer and non-summer Energy Charges from $0.01 per kWh to $0.02 per kWh;[50]
- double the current the price differential between the first and second blocks of the summer Energy Charges from $0.005 per kWh to $0.01 per kWh;[51] and
- increase the monthly Customer Charge by 89% from $2.56 to the full cost of $4.84 per month.[52]

Q. WHAT CONCERNS DO YOU HAVE WITH EPE'S PROPOSED CHANGE TO THE RESIDENTIAL SERVICE CUSTOMER CHARGE?

A. I am concerned that EPE's proposed change is a 28% increase over the current monthly Customer Charge. That alone is a significant increase that will have a greater impact on Residential Service customers with low usage. EPE's proposed increase should also be considered in conjunction with the monthly AMS surcharge rate of $2.65 that EPE has proposed in Docket No. 52040, EPE's Application for Approval of Advanced Metering System (AMS) Deployment Plan, AMS Surcharge, and Non-Standard Metering Service Fees.[53] The combination of these two charges would be a $4.94 per month increase, or

[48] Direct Testimony of Manny Carrasco at 33:29 – 31.

[49] *Id.* at 33:1 – 2.

[50] *Id.* at 34:26 – 35:9.

[51] *Id.* at 35:11 – 17.

[52] *Id.* at 40:18 – 23.

[53] Docket No. 52040, *Application of El Paso Electric Company for Approval of Advanced Metering System (AMS) Deployment Plan, AMS Surcharge, and Non-Standard Metering Service Fees*, Attachment 3, page 1.

60%, in the fixed monthly customer-related charges for EPE's Residential Service customers. That level of increase would have a significantly greater impact on low usage customers than on higher usage customers.

Q. WHAT IS YOUR RECOMMENDATION CONCERNING EPE'S PROPOSED INCREASE TO THE RESIDENTIAL SERVICE CUSTOMER CHARGE?

A. I believe the monthly customer charge should remain at its current level of $8.25 per month to enable customers, particularly low usage customers, to adjust to the impact of the AMS Surcharge. However, at a maximum, if it is determined the monthly customer charge should move towards full cost, the monthly customer charge should not be increased more than the average base rate increase for the Residential Service class.

Q. WHAT CONCERNS DO YOU HAVE WITH EPE'S PROPOSED REDUCTION OF THE ON-PEAK PERIOD FROM SIX MONTHS TO FOUR MONTHS?

A. The reduction in the on-peak period from six months to four months should be considered in conjunction with EPE's proposal to double the summer to non-summer price differential and their proposal to double the price differential between the first and second energy blocks of the summer energy charges.[54] The summer months are being reduced by 33%, when the energy consumption for Residential Service customers decreases significantly during the months of May and October compared to the remaining months of June through September. Therefore, Residential customers will experience significantly higher bills during the months of June through September.

[54] Direct Testimony of Manny Carrasco at 34:26 – 35:17.

Q. WHAT IMPACT WILL THE CHANGE IN THE DEFINITION OF THE SUMMER PERIOD HAVE ON RESIDENTIAL CUSTOMERS?

A. Most residential customers generally tend to be reactive, rather than proactive. By eliminating May from the summer period, Residential customers will first experience the significantly higher summer rates in their June bills and will experience a significantly greater differential in their monthly bills from May to June. When May is included in the summer rate period, customers will receive a higher May bill and can respond by better managing their consumption in June, when their consumption will tend to increase significantly.

In addition, because the October billing month is composed of September and October usage, including October in the summer period will ensure that all consumption for the four peak summer months of June through September is billed at the higher summer energy charge.

Q. WHAT ANALYSIS DID EPE PERFORM TO DETERMINE THE PROPOSED CHANGES TO THE PRICE DIFFERENTIAL BETWEEN THE SUMMER AND NON-SUMMER ENERGY CHARGE WAS REASONABLE AND COST-BASED?

A. In response to OPUC RFI No. 7-6, EPE stated, "The proposed increase in the price differential between summer and non-summer charges for Residential Service rates was a management decision not based on any calculations."[55] Therefore, EPE's proposed increase in the price differential between summer and non-summer charges is not supported

[55] EPE's Response to OPUC RFI No. 7-6.

by analysis, nor is it cost-based. It is essentially an aerial extraction. EPE's response to OPUC RFI No. 7-6 is provided as Attachment EDE-10.

Q. WHAT ANALYSIS DID EPE PERFORM TO DETERMINE THAT THE PROPOSED CHANGES TO INCREASE THE PRICE DIFFERENTIAL BETWEEN THE FIRST AND SECOND ENERGY BLOCK FOR THE RESIDENTIAL SERVICE SUMMER ENERGY CHARGE WAS REASONABLE AND COST-BASED?

A. In response to OPUC RFI No. 7-7, EPE stated, "The proposed increase in the price differential between the first and second blocks of the summer energy charges for the Residential Service rates was a management decision not based on any calculations."[56] Therefore, EPE's proposed price increase between the first and second summer energy blocks is not supported by analysis nor is it cost-based. It is essentially an aerial extraction. EPE's response to OPUC RFI No. 7-7 is provided as Attachment EDE-10.

Q. DID EPE PERFORM ANY CUSTOMER IMPACT ANALYSIS THAT EVALUATES THE IMPACT OF EPE'S PROPOSED CHANGE IN THE DEFINITION OF ITS SUMMER SEASON OR THE INCREASES IN THE PRICE DIFFERENTIALS BETWEEN SUMMER AND NON-SUMMER ENERGY CHARGES?

A. In EPE's response to OPUC RFI No. 7-8, EPE stated, "El Paso Electric Company ("EPE") did not prepare any customer impact analyses that separately identifies or evaluates the impact of EPE's proposed change in the definition of summer season, the increase in the

[56] EPE's Response to OPUC RFI No. 7-7.

seasonal price differential, and increase in the price differential between the first and second energy blocks for summer for the Residential Service rate."[57] EPE's response to OPUC RFI No. 7-8 is provided as Attachment EDE-11.

Q. HAS EPE DEVELOPED ANY PLANS FOR COMMUNICATING WITH RESIDENTIAL CUSTOMERS ABOUT ITS PROPOSED SIGNIFICANT CHANGES TO THE SUMMER PERIOD AND SUMMER ENERGY CHARGES?

A. No. In response to discovery requesting any communication plans that EPE has developed to fully inform customers of these significant changes, EPE stated, "El Paso Electric Company ("EPE" or "Company") has not to date developed communications for Residential Service customers that would be used following Commission approval of EPE's rate proposals."[58] EPE's response to OPUC RFI No. 7-11 is provided as Attachment EDE-12.

Q. WHAT IS YOUR RECOMMENDATION CONCERNING EPE'S PROPOSED CHANGES TO ITS DEFINITION OF THE SUMMER PERIOD AND ITS PROPOSED INCREASE IN THE PRICE DIFFERENTIALS FOR SUMMER ENERGY CHARGES?

A. I recommend EPE's proposal to reduce the summer period for the Residential Service rate be rejected and the current definition of the months of May through October not be changed.

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[57] EPE's response to OPUC RFI N0. Question 7-8.

[58] EPE's response to OPUC RFI No. 7-11.

I also recommend EPE's proposal to double the price differential for the energy charge for summer compared to non-summer months be rejected. EPE's proposed change was not based on any analysis or calculations. EPE has not provided any data that proves the change is cost-based or reasonable.

Finally, I recommend EPE's proposal to double the price differential for the energy charge between the first and second summer energy blocks be rejected. EPE's proposed change was not based on any analysis or calculations. EPE has not provided any data that proves the change is cost-based or reasonable. In addition, EPE has not prepared any plans for fully communicating these significant changes to its Residential Service customers and has not developed any customer service plans for Residential customers impacted by the proposed significant changes to EPE's summer energy charges.[59]

Q. PLEASE DISCUSS EPE'S PROPOSAL TO DRAMATICALLY INCREASE THE CUSTOMER CHARGE FOR THE RESIDENTIAL SERVICE OFF-PEAK WATER HEATING RIDER.

A. EPE is proposing to increase the monthly Customer Charge for the Residential Service Off-Peak Water Heating Rider by 89% from $2.56 to $4.84 per month.[60] EPE's rate design witness, Mr. Manny Carrasco indicates that $4.84 is the full cost.[61] However, Mr. Carrasco provides no other testimony supporting this significant increase.

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[59] EPE's response to OPUC RFI No. 7-12.

[60] Direct Testimony of Manny Carrasco at 40:18 – 23.

[61] Direct Testimony of Manny Carrasco at 40:18-23.

Q. WHAT IS YOUR RECOMMENDATION CONCERNING THE PROPOSED INCREASE TO THE MONTHLY CUSTOMER CHARGE FOR THE OFF-PEAK WATER HEATING RIDER?

A. I recommend that the increase in the customer charge be limited to 1.5 times the average base rate increase for the Off-Peak Service Rider. That level of increase should move the monthly customer charge significantly toward full cost.

b. Schedule 02 – Small General Service

Q. WHAT ISSUES WILL YOU ADDRESS RELATIVE TO THE SMALL GENERAL SERVICE RATE?

A. I will address EPE's following proposals that impact the standard Small General Service Rate and the Off-Peak Water Heating Service rate:

- set the monthly Customer Charge to collect all the customer-related costs by increasing the charge from $10.75 per month to $12.23 per month;[62]
- shorten the summer season from six months (May through October) to four months (June through September)[63];
- double the current price differential between summer and non-summer Energy Charges from $0.01 per kWh to $0.02 per kWh;[64] and
- increase the monthly Customer Charge by 89% from $2.56 to the full cost of $4.84 per month.[65]

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[62] *Id.* at 43:6 – 7.

[63] *Id.* at5 42: 12 – 13.

[64] *Id.* at 43:13 – 18.

[65] *Id.* at 44:28 – 31.

Q. WHAT CONCERNS DO YOU HAVE WITH EPE'S PROPOSED CHANGE TO THE GENERAL SERVICE CUSTOMER CHARGE?

A. EPE's proposed change is a 14% increase over the current monthly Customer Charge.[66] That alone would not have a drastic impact on most Small General Service customers. However, EPE's proposed increase should be considered along with the monthly AMS surcharge rate of $6.07 that EPE has proposed in Docket No. 52040.[67] The combination of these two charges would be a $7.55 per month increase, or 70%, in the fixed monthly customer-related charges for EPE's Small General Service customers. That level of increase would have a significantly greater impact on low usage customers than on higher usage customers.

Q. WHAT IS YOUR RECOMMENDATION CONCERNING EPE'S PROPOSED INCREASE TO THE SMALL GENERAL SERVICE CUSTOMER CHARGE?

A. I believe the increase to the monthly customer charge should be limited to half the amount necessary to move the charge to full cost. This will better enable customers, particularly lower usage Small General Service customers, to adjust to the impact of the AMS Surcharge.

Q. WHAT CONCERNS DO YOU HAVE WITH EPE'S PROPOSED REDUCTION OF THE ON-PEAK PERIOD FROM SIX MONTHS TO FOUR MONTHS?

A. The reduction in the on-peak period from six months to four months should be considered in conjunction with EPE's proposal to double the summer to non-summer price differential.

[66] $12.23 versus $10.75.

[67] Docket No. 52040, *Application of El Paso Electric Company for Approval of Advanced Metering System (AMS) Deployment Plan, AMS Surcharge, and Non-Standard Metering Service Fees*, Attachment 3, page 1.

Although the summer months are being reduced by 33%, the energy consumption tends to be significantly less during the months of May and October than in the months of June through September. Therefore, Small General Service customers can experience significantly higher bills during the months of June through September.

Q. WHAT IMPACT WILL THE CHANGE IN THE DEFINITION OF THE SUMMER PERIOD HAVE ON SMALL GENERAL CUSTOMERS?

A. Similar to residential customers, Small General Service customers tend to be reactive, rather than proactive. By eliminating May from the summer period, Small General Service customers will first experience the significantly higher summer rates in their June bills and will experience a significantly greater differential in their monthly bills from May to June. When May is included in the summer rate period, customers will receive a higher May bill and can respond by better managing their consumption in June, when their consumption will tend to increase significantly.

In addition, because the October billing month is composed of September and October usage, including October in the summer period will ensure that all consumption for the four peak summer months of June through September is billed at the higher summer energy charge.

Q. DISCUSS EPE'S PROPOSAL TO DRAMATICALLY INCREASE THE CUSTOMER CHARGE FOR THE SMALL GENERAL SERVICE OFF-PEAK WATER HEATING RIDER.

A. EPE is making the same proposed changes to the Small General Service Off-Peak Water Heating Rider as it did for the Residential Service Rider. EPE is proposing to increase the monthly Customer Charge for the Off-Peak Water Heating Rider by 89% from $2.56 to $4.84 per month. EPE's rate design witness, Manny Carrasco indicates that $4.84 is the full cost.[68] However, Mr. Carrasco provides no other testimony supporting this significant increase.

Q. WHAT IS YOUR RECOMMENDATION CONCERNING THE PROPOSED INCREASE TO THE MONTHLY CUSTOMER CHARGE FOR THE OFF-PEAK WATER HEATING RIDER?

A. I recommend that the increase in the customer charge be limited to 1.5 times the average base rate increase for the Off-Peak Service Rider. That level of increase should move the monthly customer charge significantly toward full cost.

VII. CONCLUSION

Q. PLEASE SUMMARIZE THE RECOMMENDATIONS CONTAINED IN THIS TESTIMONY.

A. In this testimony, I recommend the following:

- Adjustments EPE made to its jurisdictional and Texas retail production demand allocation factors to reflect capacity supplied by dedicated company-owned solar facilities or solar PPA should be modified to adjust for EPE's planning reserve margin of 15%;
- EPE's production plants should not be divided into peaking and non-peaking plants for the allocation of demand-related plant investment and associated expenses;

[68] Direct Testimony of Manny Carrasco at 40:18-23.

- EPE's entire demand-related production plant in service and associated expenses should be allocated among jurisdictions and among Texas retail customer classes based on the 4CP-A&E allocation method;
- EPE made an error in the Production 12CP jurisdictional and Texas retail class allocation factors EPE used for the allocation of FERC Account No. 556 – System Control and Load Dispatching Expense, and that error must be corrected;
- The energy consumed by Interruptible loads should be included in the E1ENERGY allocator;
- Class NCP demands do not adequately reflect the diversity of demands considered by EPE in planning and designing its secondary lines and transformers;
- The allocation of secondary lines, poles and fixtures, underground conduit and transformers should be allocated among Texas retail classes based on MCD, instead of NCP demands;
- FERC Account No. 904 – Uncollectible Accounts Expense should be allocated on sales revenues among all Texas retail customer classes;
- The distribution of the Texas jurisdictional base rate increase in this rate case should reflect moderation such that no class is assigned a base rate increase that is more than 1.5 times the Texas retail average base rate increase, and no class is assigned an increase that is less than half the Texas retail average base rate increase;
- It is not appropriate to increase the monthly customer charges for the Residential Service rate and the Small General Service rate in this rate case;
- EPE's proposed modifications to reduce the summer months to four months, and to double the price differential between summer and non-summer months for Residential Service and Small General Service customers should be rejected; and
- EPE's proposal to double the price differential between the charges applied to the first and second summer energy blocks for Residential Service should be rejected.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

ATTACHMENTS

List of Prior Testimony
Filed by Evan D. Evans

Year	Regulatory Commission	Docket/Case Number	Description of Proceeding	Party on Behalf Testimony was Submitted
2021	Public Utilities Commission of Texas (PUCT)	51802	Application of Southwestern Public Service Company for Authority to Change Rates	Office of Public Utility Counsel
2021	PUCT	51415	Application of Southwestern Electric Power Company for Authority to Change Rates	Texas Cotton Ginners' Association
2021	New Mexico Public Regulation Commission (NMPRC)	20-00222-UT	Joint Application of Avangrid, Inc., Avangrid Networks, Inc., NM Green Holdings, Inc., Public Service Company of New Mexico and PNM Resources, Inc. for Approval of the Merger of NM Green Holdings, Inc. with PNM Resources, Inc.	NMPRC Utility Division Staff
2019	NMPRC	19-00315-UT	Southwestern Public Service Company's Application for Approval of Continued Use of Its Fuel and Purchased Power Cost Adjustment Clause (FPPCAC)	SPS
2019	PUCT	49831	Application of Southwestern Public Service Company for Authority to Change Rates	SPS
2019	NMPRC	19-00170-UT	Application for Revision of Retail Rates	SPS
2018	PUCT	48718	Application of Southwestern Public Service Company for Authority to Implement a Net Refund for Overcollected Fuel Costs	SPS
2017	NMPRC	17-00255-UT	Application for Revision of Retail Rates	SPS
2017	PUCT	47527	Application of Southwestern Public Service Company for Authority to Change Rates	SPS
2017	PUCT	47369	Application of Southwestern Public Service Company for Authority to Implement a Fuel Surcharge	SPS
2017	PUCT	46936	Southwestern Public Service Company's Application for Approval of CCN and Operation of Wnd Generation Facilities	SPS

List of Prior Testimony
Filed by Evan D. Evans

Year	Regulatory Commission	Docket/Case Number	Description of Proceeding	Party on Behalf Testimony was Submitted
2017	NMPRC	17-00044-UT	Southwestern Public Service Company's Application for Approval of CCN and Operation of Wnd Generation Facilities	SPS
2016	NMPRC	16-00291-UT	Application of Soutwestern Public Service Company for an Accounting Order Related to Back-Billed Charges by the Southwest Power Pool	SPS
2016	PUCT	46496	Application of Soutwestern Public Service Company for an Accounting Order Related to Back-Billed Charges by the Southwest Power Pool	SPS
2016	NMPRC	16-00269-UT	Application for Revision of Retail Rates	SPS
2016	NMPRC	16-0026-UT	Application for Approval of Modification of Cost Recovery Methodology under Fuel and Purchased Power Cost Adjustment Clause	SPS
2016	PUCT	46075	Application of Southwestern Public Service Company for Authority to Implement a Net Base Rate Refund	SPS
2016	PUCT	46025	Application of Southwestern Public Service Company for Authority to Reconcile Fuel and Purchased Power Costs	SPS
2016	PUCT	45524	Application of Southwestern Public Service Company for Authority to Change Rates	SPS
2015	PUCT	45291	Application of Southwestern Public Service Company For Approval of Transaction with Xcel Energy Southwest Transmission Company, LLC and Related Approvals	SPS
2015	NMPRC	15-00343-UT	Southwestern Public Service Company's Application for Authorization to Form a Subsidiary and to Contribute Certain Transmission Assets to the Subsidiary	SPS
2015	NMPRC	15-00296-UT	In the Matter of SPS's Application for Revision of Its Retail Rates Under Advice Notice No. 258	SPS

List of Prior Testimony
Filed by Evan D. Evans

Year	Regulatory Commission	Docket/Case Number	Description of Proceeding	Party on Behalf Testimony was Submitted
2015	PUCT	45141	Application of Southwestern Public Service Company for Authority to Implement a Net Refund for Overcollected Fuel Costs	SPS
2015	NMPRC	15-00139-UT	In the Matter of SPS's Application for Revision of Its Retail Rates Under Advice Notice No. 255	SPS
2015	PUCT	44671	Joint Application of SPS and Oncor Electric Delivery Company LLC for Approval of Accounting Entries Associated with the Purchase and Sale of Facilities, and for True-up of the Gain-on-Sale Calculation Associated with Docket No. 41430	SPS
2015	PUCT	44609	Application of SPS for Authorization to Refund Amounts Received from Tri-County Electric Cooperative, Inc. Associated with Docket No. 42004	SPS
2015	PUCT	44289	Application of SPS for Authority for Authority to Implement Surcharge Associated with Docket No. 42004	SPS
2014	PUCT	43695	Application of SPS for Authority to Change Rates	SPS
2014	PUCT	42004	Application of SPS for Authority to Change Rates and to Reconcile Fuel and Purchased Power Costs for the Period July 1, 2012 through June 30, 2013	SPS
2014	PUCT	42042	Application of SPS for Approval of a Transmission Cost Recovery Factor	SPS
2013	PUCT	41852	Application of EPE to Reconcile Fuel Costs	EPE
2013	PUCT	41763	EPE's Application for a Certificate of Convenience and Necessity for Two Additional Generating Units at Montana Power Station in El Paso County	EPE
2013	NMPRC	13-00380-UT	EPE's Application for Continued Use of Fuel and Purchased Power Cost Adjustment Clause	EPE

List of Prior Testimony
Filed by Evan D. Evans

Year	Regulatory Commission	Docket/Case Number	Description of Proceeding	Party on Behalf Testimony was Submitted
2013	NMPRC	13-00297-UT	EPE's Application for a Certificate of Public Convenience and Necessity to Construct, Own and Operate Two Generating Units at Montana Power Station	EPE
2013	NMPRC	13-00176-UT	EPE's Application for Approval of New and Modified Energy Efficiency Programs for 2014, 2015 and 20161	EPE
2012	NMPRC	11-00218-UT	Establishment of a Reasonable Cost Threshold for Renewable Resource Procurement pursuant to the Renewable Energy Act	EPE
2012	NMPRC	12-00137-UT	EPE's Application for A Certificate of Public Convenience and Necessity to Construct, Own and Operate Two Generating Units at Montana Site in Texas	EPE
2012	PUCT	40301	EPE's Application to Amend Its Certificate of Convenience and Necessity for Two Generating Units at Montana Site in Texas	EPE
2012	PUCT	40094	Application of EPE to Change Rates and Reconcile Fuel Costs	EPE
2011	Federal Energy Regulatory Commission (FERC)	ER11-1915 et al	Public Service Company of New Mexico's Notice of Transmission Tariff Changes	EPE
2011	PUCT	39647	Application of EPE for a Discounted Rate Tariff for Churches Using Rate Schedule 24	EPE
2011	NMPRC	11-00276-UT	Investigation into EPE's Rates to Its Church Customers	EPE
2011	NMPRC	11-00263-UT	EPE's 2011 Procurement Plan Pursuant to Renewable Energy Act	EPE
2011	NMPRC	11-00047-UT	EPE's Application for Approval of New and Modified Energy Efficiency Programs for 2011	EPE
2010	NMPRC	10-00266-UT	Application of EPE for Approval to Recover Regulatory Disincentives and Incentives Associated with Energy Efficiency and Load Management Programs	EPE

List of Prior Testimony
Filed by Evan D. Evans

Year	Regulatory Commission	Docket/Case Number	Description of Proceeding	Party on Behalf Testimony was Submitted
2010	NMPRC	10-00200-UT	EPE's 2010 Procurement Plan Pursuant to Renewable Energy Act	EPE
2010	PUCT	38361	Application of EPE to Reconcile Fuel Costs (Severed from PUC Docket No. 37690)	EPE
2010	PUCT	38226	Application for Approval to Revise Its Energy Efficiency Cost Recovery Factor	EPE
2009	PUCT	37690	Application of EPE to Change Rates, to Reconcile Fuel Costs, to Establish Formula-Based Fuel Factors, and to Establish an Energy Efficiency Cost Recovery Factor	EPE
2009	NMPRC	09-00259-UT	EPE's 2009 Procurement Plan Pursuant to Renewable Energy Act	EPE
2009	PUCT	37086	Petition of EPE to Decrease Fuel Factor	EPE
2009	NMPRC	09-00171-UT	EPE's General Rate Case Pursuant to Commission Order	EPE
2009	NMPRC	08-00024-UT	Rulemaking to Revise 17.7.2 NMAC	EPE
2008	PUCT	35856	Petition of EPE for Authority to Increase Fuel Factor, for Fuel Surcharge, and for Related Good-Cause Exception	EPE
2008	NMPRC	08-00219-UT	EPE's 2008 Procurement Plan Pursuant to Renewable Energy Act	EPE
2008	PUCT	35204	Petition of EPE for Fuel Surcharge	EPE
2007	NMPRC	07-00411-UT	EPE Application for Approval of Energy Efficiency Programs	EPE
2007	NMPRC	07-00317-UT	Investigation Into Rates and Charges of EPE	EPE
2007	PUCT	34695	Petition of EPE to Reconcile Fuel Costs and Revenues and Request to Recover Mine Closing Cost	EPE
2007	NMPRC	06-00258-UT	El Paso Electric Company's (EPE) General Rate Case and Advice Notice	EPE

List of Prior Testimony
Filed by Evan D. Evans

Year	Regulatory Commission	Docket/Case Number	Description of Proceeding	Party on Behalf Testimony was Submitted
2005	Corporation Commission of Oklahoma (OCC)	PUD 200500177	Establishment of Purchased Power Rates and a Purchase Power Contract with Oklahoma Gas and Electric	Chermac Energy Corporation and Sleeping Bear LLC
2005	OCC	PUD 200500059	Establishment of Purchased Power Rates and a Purchase Power Contract with Oklahoma Gas and Electric	Chermac Energy Corporation and Sleeping Bear LLC
2004	PUCT	28813	Inquiry into Reasonableness of the Rates and Services of CapRock Energy Corporation	St. Lawrence Cotton Growers Assoc. and Texas Cotton Ginners Assoc.
2004	OCC	PUD 200300634	Establishment of Purchased Power Rates and Purchase Power Contract with AEP - Oklahoma	Blue Canyon Windpower V, LLC
2004	OCC	PUD 200300633	Establishment of Purchased Power Rates and Purchase Power Contract with AEP - Oklahoma	Blue Canyon Windpower II, LLC
2004	Georgia Public Service Commission (GPSC)	17688	Savannah Electric and Power Company's Application for Approval of Integrated Resource Plan	Staff of the GPSC
2004	GPSC	17687	Georgia Power Company's Application for Approval of Integrated Resource Plan	Staff of the GPSC
1998	PUCT	19502	Application of CPL for Approval of A New Interruptible Service Tariff	CPL
1998	OCC	PUD 980000210	Application of PSO for Temporary Oil Pumping Rider for Marginal Producing Oil Wells	PSO
1998	PUCT	18970	Application of WTU for Authority to Increase Fuel Factors and to Implement an Interim Surcharge of Fuel Cost Under-Recoveries	WTU
1997	PUCT	18607	Application of WTU for Authority to Reconcile Fuel Costs	WTU
1997	PUCT	16995	Joint Application of CPL, WTU, Southwestern Electric Power Company (SWEPCO) for Approval of Preliminary Integrated Resource Plans	CPL, WTU and SWEPCO

List of Prior Testimony
Filed by Evan D. Evans

Year	Regulatory Commission	Docket/Case Number	Description of Proceeding	Party on Behalf Testimony was Submitted
1997	OCC	PUD 960000214	Application of the Public Utility Division of the OCC to Review the Rates and Charges of Public Service Company of Oklahoma (PSO)	PSO
1997	PUCT	17160	Application of WTU for Authority to Increase Fuel Factors and to Implement an Interim Surcharge of Fuel Cost Under-Recoveries	WTU
1995	PUCT	13369	Application of WTU for Authority to Change Rates and Reconcile Fuel costs	WTU
1994	PUCT	11630	Application of WTU for Approval of Calculation of House Bill 11 Tax Adjustment Factors for 1993	WTU
1992	PUCT	10818	Application of WTU for Approval of Calculation of House Bill 11 Tax Adjustment Factors for 1992	WTU
1990	PUCT	9561	Application of Central Power and Light Company (CPL) for Authority to Change Rates	CPL
1983	PUCT	5204	Application of West Texas Utilities Company (WTU) for Authority to Change Rates	WTU

Office of Public Utility Counsel's
Adjustments to EPE's Production and Transmission Jurisdictional Allocators
(Modification to Solar Capacity Adjustments)

EPE's Production and Transmission Jurisdictional Allocators

Description	Annual Energy at Source, kWh	**E1ENERGY** Energy Allocator	4CP Average Demand	4CP Demand % by Jurisdiction	**D1PROD** 4CP-A&E	12-CP Average Demand	**DPROD12** 12CP Demand Allocator	**DTRAN12** 12CP Demand Allocator
Texas Retail Total Firm Load	6,346,682,091		1,493,737			1,122,007		
Less: EPE's Texas Solar Adjustment	241,039		120			74		
Adjusted Texas Retail Firm Load	6,346,441,052	78.7148%	1,493,617	81.1247%	81.1610%	1,121,933	80.6165%	80.6165%
New Mexico Retail Total Firm Load	1,786,583,763		370,100			282,805		
Less: EPE's New Mexico Solar Adjustment	135,406,792		35,532			22,027		
Adjusted New Mexico Retail Firm Load	1,651,176,971	20.4795%	334,568	18.1718%	18.1386%	260,778	18.7382%	18.7382%
FERC Total Firm Load	64,959,649	0.8057%	12,952	0.7035%	0.7004%	8,981	0.6453%	0.6453%
Total EPE Firm Load	8,062,577,672	100.0000%	1,841,137	100.0000%	100.0000%	1,391,692	100.0000%	100.0000%

OPUC's Production and Transmission Jurisdictional Allocators

Description	Annual Energy at Source, kWh	**E1ENERGY** Energy Allocator	4CP Average Demand	4CP Demand % by Jurisdiction	**D1PROD** 4CP-A&E	12-CP Average Demand	**DPROD12** 12CP Demand Allocator	**DTRAN12** 12CP Demand Allocator
Texas Retail Total Firm Load	6,346,682,091		1,493,737			1,122,007		
Less:OPUC's Texas Solar Adjustment	241,039		104			65		
Adjusted Texas Retail Firm Load	6,346,441,052	**78.7148%**	1,493,632	80.9212%	**80.9595%**	1,121,943	**80.4505%**	**80.4505%**
New Mexico Retail Total Firm Load	1,786,583,763		370,100			282,805		
Less: OPUC's New Mexico Solar Adjustment	135,406,792		30,897			19,154		
Adjusted New Mexico Retail Firm Load	1,651,176,971	**20.4795%**	339,203	18.3771%	**18.3418%**	263,651	**18.9055%**	**18.9055%**
FERC Total Firm Load	64,959,649	**0.8057%**	12,952	0.7017%	**0.6986%**	8,981	**0.6440%**	**0.6440%**
Total EPE Firm Load	8,062,577,672	**100.0000%**	1,845,787	100.0000%	**100.0000%**	1,394,575	**100.0000%**	**100.0000%**

Office of Public Utility Counsel's
Adjustments to EPE's Production and Transmission Jurisdictional Allocators
(Modification to Solar Capacity Adjustments)

Change from EPE to OPUC Production and Transmission Jurisdictional Allocators

Description	**E1ENERGY** Energy Allocator	4CP Demand % by Jurisdiction	**D1PROD** 4CP-A&E	**DPROD12** 12CP Demand Allocator	**DTRAN12** 12CP Demand Allocator
Texas Retail	0.0000%	-0.2035%	-0.2015%	-0.1659%	-0.1659%
New Mexico Retail	0.0000%	0.2053%	0.2032%	0.1673%	0.1673%
FERC	0.0000%	-0.0018%	-0.0017%	-0.0013%	-0.0013%
Total EPE Firm Load	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%

Comparison of
4CP-A&E Allocator Using 4CP Load Factor vs 1CP Load Factor

Jurisdiction	4CP-A&E Calculated Using 1CP Load Factor	EPE's Proposed 4CP-A&E Calculated Using 4CP Load Factor	Difference
EPE Calculated Allocators			
Texas Retail Jurisdiction	81.3643%	**81.1610%**	**-0.2032%**
New Mexico Retail Jurisdiction	17.9441%	18.1386%	0.1945%
FERC Jurisdiction	0.6916%	0.7004%	0.0088%
Total EPE	100.0000%	100.0000%	0.0000%
Calculated with OPUC Solar Adjustment			
Texas Retail Jurisdiction	81.1447%	**80.9595%**	**-0.1851%**
New Mexico Retail Jurisdiction	18.1655%	18.3418%	0.1763%
FERC Jurisdiction	0.6898%	0.6986%	0.0088%
Total EPE	100.0000%	100.0000%	0.0000%

Analysis of
Historical Generation by Season for
Generation Units Designated as Peaking Units

MWh Generated in Non-Summer Months

Year	Copper UNIT 1	Rio Grande UNIT 9	Montana UNIT 1	Montana UNIT 2	Montana UNIT 3	Montana UNIT 4	Total Peaking Units	Other Natural Gas-Fired
2017	4,880	62,639	193,688	163,651	95,684	150,829	671,371	1,420,219
2018	16,553	22,909	223,364	208,723	109,133	138,754	719,436	2,170,880
2019	17,066	97,468	176,960	200,136	128,309	170,564	790,503	2,095,793
2020	15,768	126,523	152,700	148,843	38,363	161,390	643,587	2,086,937

MWh Generated in Summer Months

Year	Copper UNIT 1	Rio Grande UNIT 9	Montana UNIT 1	Montana UNIT 2	Montana UNIT 3	Montana UNIT 4	Total Peaking Units	Other Natural Gas-Fired
2017	14,033	83,399	160,702	134,896	18,913	126,680	538,623	1,214,007
2018	30,734	63,671	65,783	147,724	126,306	129,192	563,410	2,326,906
2019	22,468	166,338	120,154	87,048	81,298	85,435	562,741	1,730,209
2020	17,630	155,626	118,570	106,223	55,295	88,803	542,147	1,527,674

% of Annual MWh Generated in Non-Summer Months

Year	Copper UNIT 1	Rio Grande UNIT 9	Montana UNIT 1	Montana UNIT 2	Montana UNIT 3	Montana UNIT 4	Total Peaking Units	Other Natural Gas-Fired
2017	25.80%	42.89%	54.65%	54.82%	83.50%	54.35%	**55.49%**	**53.91%**
2018	35.01%	26.46%	77.25%	58.56%	46.35%	51.78%	**56.08%**	**48.27%**
2019	43.17%	36.95%	59.56%	69.69%	61.21%	66.63%	**58.42%**	**54.78%**
2020	47.21%	44.84%	56.29%	58.35%	40.96%	64.51%	**54.28%**	**57.74%**

Comparison of
Production Demand Allocators by Texas Retail Class
EPE Filed vs. OPUC's Revised Solar Adjustment

Rate Class	EPE Filed D1PROD 4CP-A&E	OPUC Rev. D1PROD 4CP-A&E	Difference
Residential Service	54.8465%	54.8468%	0.0003%
Small General Service	4.7233%	4.7233%	0.0000%
Outdoor Recreational Lighting Service	0.0302%	0.0302%	0.0000%
Street Lighting	0.2962%	0.2962%	0.0000%
Traffic Signals	0.0171%	0.0171%	0.0000%
Municipal Pumping Service	1.5913%	1.5913%	0.0000%
Electrolytic Refining Service	0.5159%	0.5159%	0.0000%
Off Peak Water Heating Service	0.0421%	0.0421%	0.0000%
Irrigation Service	0.0963%	0.0963%	0.0000%
General Service	21.0276%	21.0275%	-0.0001%
Large Power Service	6.8494%	6.8493%	-0.0001%
Petroleum Refining Service	2.7655%	2.7654%	-0.0001%
Private Area Lighting Service	0.2204%	0.2204%	0.0000%
Electric Furnace Rate	0.3413%	0.3413%	0.0000%
Military Reservation Service	3.4816%	3.4815%	0.0000%
Cotton Gin Service	0.0131%	0.0131%	0.0000%
City and County Service	3.1423%	3.1423%	0.0000%
Texas Total Firm Load	100.0000%	100.0000%	0.0000%

Comparison of Production Demand Allocators by Texas Retail Class EPE Filed vs. OPUC's Revised Solar Adjustment

Rate Class	EPE Filed 4CP Demands	OPUC Rev. 4CP Demands	EPE Filed 4CP Allocation Percentages	OPUC Rev. 4CP Allocation Percentages	Difference
Residential Service	824,888	824,896	55.2275%	55.2275%	0.0000%
Small General Service	70,964	70,965	4.7511%	4.7511%	0.0000%
Outdoor Recreational Lighting Service	0	0	0.0000%	0.0000%	0.0000%
Street Lighting	0	0	0.0000%	0.0000%	0.0000%
Traffic Signals	194	194	0.0130%	0.0130%	0.0000%
Municipal Pumping Service	23,808	23,808	1.5940%	1.5940%	0.0000%
Electrolytic Refining Service	7,736	7,736	0.5180%	0.5180%	0.0000%
Off Peak Water Heating Service	381	381	0.0255%	0.0255%	0.0000%
Irrigation Service	1,448	1,448	0.0970%	0.0970%	0.0000%
General Service	315,623	315,626	21.1314%	21.1314%	0.0000%
Large Power Service	102,639	102,640	6.8718%	6.8718%	0.0000%
Petroleum Refining Service	41,371	41,372	2.7699%	2.7699%	0.0000%
Private Area Lighting Service	0	0	0.0000%	0.0000%	0.0000%
Electric Furnace Rate	5,127	5,127	0.3432%	0.3432%	0.0000%
Military Reservation Service	52,226	52,226	3.4966%	3.4966%	0.0000%
Cotton Gin Service	17	17	0.0011%	0.0011%	0.0000%
City and County Service	47,195	47,195	3.1598%	3.1598%	0.0000%
Texas Total Firm Load	1,493,617	1,493,632	100.0000%	100.0000%	0.0000%

Comparison of
Production Demand Allocators by Texas Retail Class
EPE Filed vs. OPUC's Revised Solar Adjustment

Rate Class	EPE Filed 12CP Demands	OPUC Rev. 12CP Demands	EPE Filed 12CP Allocation Percentages	OPUC Rev. 12CP Allocation Percentages	Difference
Residential Service	560,602	560,607	49.9675%	49.9676%	0.0000%
Small General Service	53,476	53,477	4.7665%	4.7665%	0.0000%
Outdoor Recreational Lighting Service	1,708	1,708	0.1522%	0.1522%	0.0000%
Street Lighting	3,022	3,022	0.2694%	0.2694%	0.0000%
Traffic Signals	194	194	0.0173%	0.0173%	0.0000%
Municipal Pumping Service	21,481	21,481	1.9147%	1.9147%	0.0000%
Electrolytic Refining Service	7,391	7,391	0.6588%	0.6588%	0.0000%
Off Peak Water Heating Service	486	486	0.0433%	0.0433%	0.0000%
Irrigation Service	784	784	0.0699%	0.0699%	0.0000%
General Service	255,405	255,407	22.7647%	22.7647%	0.0000%
Large Power Service	89,640	89,640	7.9898%	7.9897%	0.0000%
Petroleum Refining Service	39,661	39,661	3.5350%	3.5350%	0.0000%
Private Area Lighting Service	2,262	2,262	0.2016%	0.2016%	0.0000%
Electric Furnace Rate	5,127	5,127	0.4569%	0.4569%	0.0000%
Military Reservation Service	45,955	45,955	4.0960%	4.0960%	0.0000%
Cotton Gin Service	182	182	0.0162%	0.0162%	0.0000%
City and County Service	34,556	34,557	3.0801%	3.0801%	0.0000%
Texas Total Firm Load	1,121,933	1,121,943	100.0000%	100.0000%	0.0000%

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
CITY OF EL PASO'S NINTH REQUEST FOR INFORMATION
QUESTION NOS. CEP 9-1 THROUGH CEP 9-43

CEP 9-28:

Are interruptible loads excluded from the E1ENERGY allocation factor for both jurisdictional allocation and retail class allocation? Please explain why interruptible loads are excluded from the E1ENERGY allocation factor. Does the Company contend that interruptible customers receive no benefit from the generation output supported by non-fuel production O&M expense? Please explain this answer.

RESPONSE:

Yes. The E1ENERGY allocator excludes interruptible (non-firm) kilowatt-hours ("kWh") in both jurisdictional and rate class allocations. The E1ENERGY allocator is used to allocate energy-related generation operation and maintenance ("O&M") expenses in the cost of service. Since the results of these allocations in the cost of service are used to determine EPE's firm base rates, then non-firm kWh should not be included in allocating O&M production expenses. Therefore, just like non-interruptible customers, interruptible customers receive the same treatment by using only their firm kWh in determining the production O&M costs included in their firm base rates.

Preparer: Adrian Hernandez Title: Senior Rate Analyst – Rates

Sponsor: Adrian Hernandez Title: Senior Rate Analyst – Rates

SOAH DOCKET NO. 473-15-5257
PUC DOCKET NO. 44941

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

EL PASO ELECTRIC COMPANY'S RESPONSE TO OFFICE OF PUBLIC UTILITY COUNSEL'S FIFTH REQUEST FOR INFORMATION QUESTION NOS. OPUC 5-1 THROUGH OPUC 5-30

OPUC 5-10:

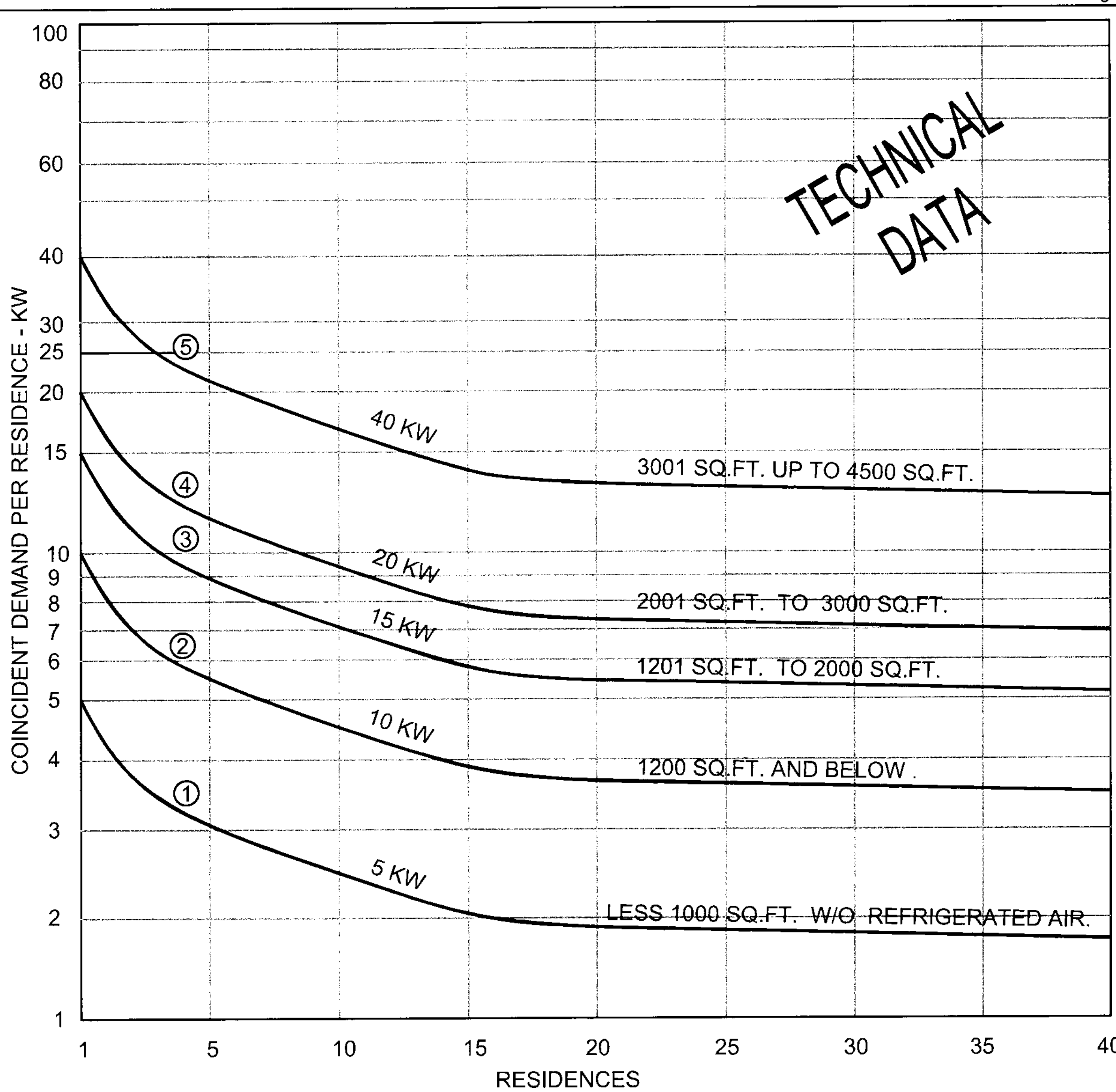
Please provide all studies which El Paso has conducted regarding the diversity of customer loads at the line transformer for (a) single-family residential; (b) multi-family residential; and (c) small commercial customers.

RESPONSE:

OPUC 5-010 Attachment 1 is EPE's standard chart used to determine the diversity for single-family residential. OPUC 5-010 Attachment 2 is EPE's guidelines to consider diversity of various customer loads.

Preparer: Omar Gallegos — Title: Manager-Asset Management Services

Sponsor: R. Clay Doyle — Title: Vice President-T&D and System Planning



NOTES:

1. Follow one of the family of lines representing the estimated demand per residence to the vertical line representing the number of residences to be served. A horizontal line from this point will determine the coincident demand per residence which when multiplied by the number of residences will determine transformer size. This curve should also be used to determine secondary size and length when used with DSO 405 / DSU 405.
2. Curve 1: mobile homes or single family homes under 1200 square feet, gas heated apartment units without refrigerated air conditioning.
   Curve 2: single family homes or mobile homes greater than 1200 square feet and below, all electric apartment units.
   Curve 3: single family homes greater than 1201 square feet but less than 2000 square feet.
   Curve 4: single family homes greater than 2001 square feet but less than 3000 square feet.
   Curve 5: single family homes greater than 3001 square feet but less than 4500 square feet.
   For homes above 4500 square feet, each case needs to be analyzed using diversified load.

DIVERSIFIED DEMAND CHART

ORIG. DATE: 10/01/93
REV. DATE: 04/05/11

EL PASO ELECTRIC CO. DISTRIBUTION STANDARD

T.D. DSU 1730
PAGE 1 OF 1

Demand Diversity as Applied to Transformer Selection and Voltage Drop Calculations

Goal: To gain an understanding of basic diversity concepts. To apply diversity principles toward residential subdivision design, commercial or industrial distribution transformer selection, and amperage calculations used in voltage drop analysis. To understand and apply alternative transformer sizing techniques.

Definitions:

Watts - Measure of power which is the time rate in which work is done, 746 watts is equal to one horsepower.

Volt-Amps - Measure of apparent power, Volt-Amps = (Applied Volts) x (Applied Amps), is the vector sum of watts and vars.

Volt-Amps Reactive - Measure of the reactive component of an electrical load, causes amps to flow but provides no power toward the accomplishment of work.

Demand - "the load at the receiving terminals averaged over a specific interval of time".

Demand can be measured in KW, KVA, KVARS, or Amps.

Peak (Maximum Demand) - "the greatest of all demands which have occurred during the specified period of time".

Demand Interval - "the period over which the demand is averaged".

Diversified Demand - "the demand of the composite group, as a whole, of somewhat unrelated loads over a specific period of time".

Diversity Factor - "the ratio of the individual maximum demands of the various subdivisions of a system to the maximum demand of the whole system".

$$DF = (dl + d2+d3+d_{n})/D_{system}$$

Example: A system has 4 connected loads measuring 24, 55, 13, and 76 KVA each. The measured demand of the system is 210 KVA. Therefore, the diversity factor is equal to:

$$(24 + 55 + 13 + 76) /210 = 0.80 \text{ or, } 80\%$$

Load Diversity - "the difference in the sum of the peaks of two or more individual loads and the peak of the combined load".

Connected Load - "the sum of the continuous ratings of the load-consuming apparatus connected to the system".

Load Factor - "the ratio of the average load over a designated period of time to the peak load occurring on that period".

LF = (Average Load x Time) / (Peak Load x Time), or
LF = (Total KW-Hrs) / (Peak KW x Hrs)

Example: A customer has a peak demand of 100 KW during the month of April. If their energy usage was 45,000 KW-Hrs, what is their load factor?

LF = (45,000) / (100 x 24 x 30) = 0.625 or, 62.5%

Diversity, General Concept:
The basic concept of demand diversification is that the overall demand on a given portion of a system is a function of the total number of attached loads. That is, system demand will usually be less than the sum of the connected peak loads. This diversity will vary depending on the nature of the load. Looking at one extreme, if 20 - 100 watt street lamps are served from one transformer, the diversity is close to unity (1) as the lights will turn on and off at the same time and will require the same amount of power. In residential subdivisions, there is a great deal of opportunity for diversification as individual routines and load types vary from resident to resident.

There are five practical uses for diversity concepts as they relate to Distribution Planners.

1. Residential subdivision design
2. Riser fuse selection
3. Secondary circuit current flow analysis
4. Transformer selection and
5. Feeder load analysis

<u>Case 1 - Residential Subdivision Design</u>

Using the Diversity Tool:
Diversity concepts for residential design should be considered for riser fuse, transformer and secondary conductor sizing. Diversity concepts can be applied to voltage drop analysis calculations as well. The first step is to determine the average peak demand of the homes in the subdivision under consideration. This can be accomplished by using the appropriate diversity curve on the Diversified Demand Chart excel spreadsheet tool. But, first, we need to know some information about the homes that are to be constructed in the subdivision.

Although there are many variables that contribute to the ultimate demand of a given residence, the average size of the proposed homes is probably the best average indicator of expected demand. By analyzing the average lot size in the development and by contacting the developer or builders about the expected size of homes within the development, a Planner can obtain this information. Additionally, other information, such as whether the homes will be all electric, have electric water heaters, electric ranges or refrigerated air conditioning, can also be obtained by builders that are expected to construct in the subdivision.

The Diversified Demand Chart tool referred to above enables the entry of the listed variables to calculate results for a given circuit segment. Refer to the instructions below.

This chart is to be used with homogenous (similar load types) loads only! When used properly, the chart will provide a means of estimating the demand kVA for transformers, line segments, and fuses based upon 1) the square footage of the average home within a development, 2) whether the homes are considered "all electric", 3) the expected refrigerated air conditioning tonnage, and 4) any other known electrical load.

Cells highlighted in light blue are the data input cells. Each of these cells except for B21 (Number of Loads) have a valid list of domain values through a drop down list. Select the value that most closely matches the design parameter from each of the drop down options. Below is a description of the required input to the spreadsheet:

1. Square Footage: This is cell contains a coded domain list of the estimated average area, in square feet, of the residences in the study area. KVA load is calculated based upon an estimated KVA demand per the residence input square footage **(a Power Factor of 85% is assumed for these calculations)**. If better load information can be acquired than this Square Footage estimation, select zero from the drop down list and enter the more accurate load data in the Other Loads cell, C10.
2. All Electric: There is a coded domain value of Yes and No for this cell. If Yes is selected, a factor of 20% will be added to the Square Footage value calculated above in KVA Load cell C7. The Yes value is to be used if the residences have electric water heating and electric kitchen appliances.
3. Refrigerated Air: There is a coded domain value of Yes and No for this cell also. If Yes is selected, the KVA Load for each refrigerated air conditioning listed in cells B14 through B18 will be added to the KVA Load cell C9.
4. Other Loads: Enter other identifiable electrical loads, (in KVA), that will likely be utilized throughout the residential development under study. If better load information can be acquired than the Square Footage estimation above, enter that load data here, (set square footage to zero).
5. Refrigerated Air Units: Enter the size of each refrigerated air conditioning unit from the drop down list provided. Up to five individual units may be specified.

6. Number of Loads: This value should reflect all residences that contribute to the current flow through section of the circuit under analysis. For transformer analysis Number of Loads will be the number of individual customer loads to be connected to the transformer being studied. Likewise, for line segment and fuse current analysis include the total number of residences in the study area that will cause current to flow. This can be done separately for both normal and emergency operating conditions.
7. Load Voltage: There are three options on the drop down list for this entry. 1) Select .24 when the analysis concerns transformer or secondary line segment loads. 2) Select 7.97 when the analysis concerns line fuse or primary line segment loads on 13.8 kV feeders. 3) Select 13.8 when the analysis concerns line fuse or primary line segment loads on 23.9 kV feeders.

This tool can be used to determine riser fuse size, primary and/or secondary conductor size, and transformer size. **If actual load documentation can be acquired, use that information instead of the Square Footage estimation and enter it in the Other Loads cell.**

Should you acquire more detailed load information about homes in a given subdivision, use that information in lieu of the general rules listed above. If average home size information is unavailable, use lot size as a general guide. Lots with less than a 60 foot front are likely to correspond to homes less than 1200 square feet, (< 10 kVA Curve).
Similarly, for average lot fronts between 60 and 100 feet use the 10 – 30 kVA Curve; and for 100 to 150 feet fronts, use the > 30 kVA Curve. Lots larger than this may have virtually any size of home, (mobile home to mansion). Check with any covenants that the development may have for home size restrictions and take care in noting slopes that may occupy a large square footage percentage of the lot.

Riser fuse/cutout sizing:
The first consideration in sizing any fuse should be fault current coordination, (this will be discussed in a future session). The next consideration should be the load that the fuse, and cut-out, are expected to serve. After selecting the appropriate diversity curve and determining the maximum number of lots that the riser fuse will feed, the diversified demand can be calculated.

Example: A 200 lot subdivision served from two risers is being designed on a 13.8KV feeder.

If the average home size for this development is 2250 square feet, the Diversified Demand Chart tool will select the 10 – 30 kVA curve to calculate load based upon square footage. In this scenario, there will be no refrigerated air conditioning or other load. This results in an estimated value of peak load of 10.13 kVA per home.

Since it is possible that either riser could carry the entire load of the development, each riser fuse must be sized to accommodate all load that the 200 lots generate. So, the Total Loads value must be set to 200. This results in a total diversified of:

10.13 x 200 x .35 (provided by the Diversified Demand Chart tool) = 708.75 KVA

From this the diversified current of each riser under full load will be;

708.75 KVA/ 7.97KV = 88.93 amps

Therefore, a 100 amp cutout is adequate and a fuse capable of handling 89 amps of continuous current is needed. Above 100 amps, the load will need to be segmented further, (by phase distribution or additional feed points), or the Distribution Systems Engineering group will need to be contacted.

Residential Transformer Sizing:

A similar procedure to that used for riser fuse and cutout sizing can be applied to sizing transformers in a residential subdivision. The new residential design standard indicates a maximum of 12 lots served per transformer in underground residential subdivisions. So, if in this design it is desired to serve 12 customers from a single transformer, the Diversified Demand Chart Tool can help with the selection of the proper transformer size. If the Number of Loads value is changed to 12, the tool indicates that the total diversified load is 58.1 kVA. So, a 75 KVA transformer is an appropriate selection.

It should be remembered that if the Diversity Curve changes or if the number of residences served by a given transformer changes, a separate analysis is needed to determine the transformer size. Also, keep in mind other factors such as voltage regulation or flicker may affect the ultimate transformer size needed.

Voltage Regulation:

Once again there is much similarity in the way diversity is used when calculating load currents in a voltage regulation problem. The methodology as it relates to diversity will only be described here as a later section will explain the mechanics of voltage regulation calculations. The main difference between Voltage Regulation diversity and those previously described is that an iterative process is needed with Voltage Regulation as the number of loads connected to the network under investigation changes as the problem moves toward the solution.

Example: Assuming that the transformer discussed above has secondary cable extending from the transformer in two directions, (each serving 4 customers), a secondary cable run across the street to serve two residences, and two residences served directly from the transformer. Typically, our Voltage Regulation analysis would be focused on one of the secondary cable runs that serve the four customers that have the longest linear distance from the transformer. So, select the cable run serving four customers that are most distal from the transformer. After changing the Number of Customers input to 4, the Diversified Demand Chart Tool calculates a load current of 119.62 amps for the four customers. Use this value, the cable impedance, and the linear distance of the cable to calculate the voltage drop through that cable segment. Similarly, repeat the sequence (changing the Number of Loads to 2) for the next two customers (72.09 amps), and finally, the current for the service run to the last customer (changing the Number of Loads to 1), providing a load current of 42.19 amps.

Case 2 - Commercial or Industrial Transformer Selection

There are three techniques that can be used to determine transformer sizing for commercial or industrial customers.

1) Probably the best method is to use historical data from exact or similar installations. For example, if a new McDonalds is proposed, look up the demand history from other McDonalds already in service on the Company CIS. Find a recent installation and that had already been through at least one summer season. Make sure that the proposed unit will be similarly constructed, (square footage, air conditioning, etc.), to the unit from which you are obtaining information. If the customer you are obtaining load history from has a recording meter, make sure you obtain KVA readings. If they do not have a recording meter, then a power factor estimate will be needed. Depending on the type of equipment that the customer has, power factor estimates should be between 75 to 90%. It is recommended that a power factor of 88% be used for "typical" commercial customers.

2) Another good method is using customer load data from panel schedules or riser diagrams. This can be more of an art than a science but there are certain "common sense" things to look for. The first is to separate the heating from the air conditioning load. Use the larger of the two and make sure that the other is not added to the total connected load. Also, check to see if the engineer included the 25% overload of the largest motor. This is to assure that the internal wiring can accommodate motor start-up current but it is transient. For transformer loading considerations, this is negligible (**please keep in mind that voltage flickers may be a problem, flicker calculations will be provided in another paper**). Try to group loads into like types (lighting with lighting, outlets with outlets, etc.). Once this is accomplished, individual diversity factors can be applied to each of these load groupings. These diversity factors will vary depending on the nature of the business. For example, the motor load diversity factor of a 5 employee job shop with ten different motor driven tools will be quite different from a 10 pump PSB pumping station that lists only one unit as an emergency back-up. Try to obtain as much specific information about the new load as is practical so that you may have a better feel for diversity factor estimation. As a **general** guide, listed below are diversity factors that can be used for load groups. Keep in mind that these diversity factors vary with the number of loads within a given load grouping as well as with the type of load. Also, this list is published without any specific knowledge of a given customer's load.

Diversity Factors

Outlets	15%
Lighting, (intemal)	70%
Lighting, (external)	0% if peak is expected during day, 90% if at night
Air Conditioning	80% if larger than heating else 0%
Heating	80% if larger than air conditioning else 0%
Motors	75% to 30%, if many lean to 30% if few toward 75%
Chillers	75% to 30%, if many lean to 30% if few toward 75%
Special Equipment	80% to 50%, if many lean to 50% if few toward 80%
Miscellaneous	10%
Spare	0%

The final expected demand should be in the range of 40 to 60% of connected load depending on the nature of the business.

When obtaining panel schedule loads, note the units that are used to derive the total connected load. Usually the units will be in amperes as the engineer is concerned with sizing conductors and breakers. If load is listed in amperes, it will not be necessary to apply a power factor to the Volts times Amps times Square Root of three calculation as the result is already in kVA.

3) Sometimes, especially with smaller commercial customers, only connected load or main panel size information is given. There is no opportunity to diversify load since individual loads have been combined or are unknown at that time. If there are no similar customers to compare load with, a percentage of connected load or panel size should be used. Typically, these percentages will fall between 40 and 60% of connected load or panel size. A range of 45 to 50% usually will cover most of these customers (When panel size information is the sole information source, lean toward the lower percentages listed).

Strip shopping center loads are often presented in this manner as tenant load information may not yet be available. In this scenario, remember that the transformer is going to serve more than one customer, usually through a main panel and a metered gutter. So, not only do you have in individual load diversity, you have diversity among the customer base as well. Also, the shopping center may not be 100% occupied providing further opportunity to reduce the estimated demand.

4) Pumps are another common load that Planners encounter. As a rule of thumb, the pump motor horsepower corresponds directly with KVA. However, keep in mind that the horsepower rating of the pump motor is the maximum load that the motor can accommodate on a constant basis. Most engineers will not design a system so finely that the work needed is exactly equal to the motor's horsepower rating. A recommended guideline for these loads would be between 60 to 80% of the motor's nameplate rating. So, a 100 horsepower motor would have an estimated demand of between 60 to 80 KVA.

It should be remembered that decisions concerning transformer size selection is an economic decision. Design considerations have been provided in this paper but they will not guarantee that some percentage of the time a transformer will be undersized and have to be changed. It is not the intent of this paper to design for anomalies. Anomalies can be discovered by researching the customer thoroughly to determine specific load profiles. The guidelines provided will provide accurate transformer sizing the vast majority of the time but will miss some anomalies. It is important that the Planner not "play it safe" by substituting anomaly designs for sound customer load analysis as this will cause the Company to bear excess transformer costs, (initial price and additional transformer loss cost).

Finally, the guideline for maximum load percentage on a given transformer should be discussed. In general, underground transformers should not be loaded beyond their nameplate rating, (100%). Overhead transformers can be loaded to 130% of their nameplate rating. An issue to consider when selecting a transformer size is load factor. Load factor is a measure of the percentage of time that a load is near or at peak demand) over the period of study. Load factors above 75% indicate that there probably is not much difference between the peak and lowest demand. In any event, the transformer will not have much opportunity to cool. If the estimated demand is at borderline between two transformer sizes, select the larger unit. Conversely, if load factor is less than 30%, choose the smaller unit.

EL PASO ELECTRIC COMPANY
Analysis of
Maximum Class Demands, Non-Coincident Peak Demands and Diversity Factors
for Secondary Voltage Custom Classes

Line No.	Rate	Description	Maximum Class Demand @ Source	Diversity Factor	Non-Coincident Peak Demand @ Source	MCD Allocation by Class	NCP Allocation by Class
1	TXRT01 - S	Residential Service	990,694	174.46%	1,728,334	60.487%	67.856%
2	TXRT02 - S	Small General Service	83,646	158.18%	132,309	5.107%	5.195%
3	TXRT07 - S	Outdoor Recreational Lighting Service	6,426	103.50%	6,651	0.392%	0.261%
4	TXRT08 - S	Street Lighting	9,067	100.00%	9,067	0.554%	0.356%
5	TXRT09 - S	Traffic Signals	195	100.00%	195	0.012%	0.008%
6	TXRT11 - S TOU	Municipal Pumping Service	31,476	155.69%	49,005	1.922%	1.924%
7	TXRTWH	Water Heating Service	3,999	224.68%	8,984	0.244%	0.353%
8	TXRT22 - S	Irrigation Service	2,284	188.58%	4,307	0.139%	0.169%
9	TXRT24 - S	General Service	367,170	121.09%	444,617	22.418%	17.456%
10	TXRT25 - S	Large Power Service	78,607	116.75%	91,774	4.799%	3.603%
11	TXRT28 - S	Private Area Lighting Service	6,839	100.00%	6,839	0.418%	0.269%
12	TXRT34 - S	Cotton Gin Service	1,931	100.06%	1,933	0.118%	0.076%
13	TXRT41 - 24 S	City and County Service	55,521	113.59%	63,065	3.390%	2.476%
14	Total Texas Secondary Voltage Service Classes		1,637,855	155.51%	2,547,078	100.000%	100.000%

Source of Data: WP P-07 filed electronically by EPE

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

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

EL PASO ELECTRIC COMPANY'S RESPONSE TO
OFFICE OF PUBLIC UTILITY COUNSEL'S
SEVENTH REQUEST FOR INFORMATION
QUESTION NOS. OPUC 7-1 THROUGH OPUC 7-12

OPUC 7-6:

Please provide a detailed explanation and all calculations and workpapers supporting the proposed increase in the price differential between summer and non-summer charges for the Residential Service rates.

RESPONSE:

Please see the discussion starting on page 26, lines 15 through 22 and page 34, line 26, through page 35, line 9, of the Direct Testimony of El Paso Electric Company ("EPE") witness Manuel Carrasco.

The proposed increase in the price differential between summer and non-summer charges for the Residential Service rates was a management decision not based on any calculations. The proposed shortened summer season provides the opportunity to increase the price differential to provide a strong pricing signal toward conservation during the proposed 4-month summer season without over-burdening EPE's customers for too long a period during the year. EPE sought to shorten the summer season from the current 6-month period to reflect its actual system peak period more closely and to be more consistent with other tariffs. The proposed shortened summer season and the proposed increase in the price differential between summer and non-summer charges for the Residential Service rates are intended to reduce peak demand that have contributed to EPE's declining load factor.

Preparer: Manuel Carrasco — Title: Manager – Rate Research

Sponsor: Manuel Carrasco — Title: Manager – Rate Research

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 OFFICE OF PUBLIC UTILITY COUNSEL'S SEVENTH REQUEST FOR INFORMATION QUESTION NOS. OPUC 7-1 THROUGH OPUC 7-12

OPUC 7-7:

Please provide a detailed explanation and all calculations and workpapers supporting the proposed increase in the price differential between the first and second blocks of the summer energy charges for the Residential Service rates.

RESPONSE:

Please see the discussion starting on page 35, lines 11 through 17, of the Direct Testimony of El Paso Electric Company ("EPE") witness Manuel Carrasco.

The proposed increase in the price differential between the first and second blocks of the summer energy charges for the Residential Service rates was a management decision not based on any calculations. The proposed shortened summer season provides the opportunity to increase the price differential to provide a strong pricing signal toward conservation during the proposed 4-month summer season without over-burdening EPE's customers for too long a period during the year. EPE sought to shorten the summer season from the current 6-month period to reflect its actual system peak period more closely and to be more consistent with other tariffs. The proposed shortened summer season and the proposed increase in the price differential between the first and second blocks of the summer energy charges for the Residential Service rates are intended to incent residential customers to reduce peak demands that have contributed to EPE's declining load factor.

Preparer: Manuel Carrasco — Title: Manager – Rate Research

Sponsor: Manuel Carrasco — Title: Manager – Rate Research

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 OFFICE OF PUBLIC UTILITY COUNSEL'S SEVENTH REQUEST FOR INFORMATION QUESTION NOS. OPUC 7-1 THROUGH OPUC 7-12

OPUC 7-8:

Please provide all customer impact analyses prepared by EPE that identifies or evaluates the impact of EPE's proposed change in the definition of summer season, the increase in the seasonal price differential and increase in the price differential between the first and second energy blocks for summer for the Residential Service rate, either separately by proposed change or for the total of all combined changes. Include any analysis of impacts by usage block frequency or by number of customers by impact percentage. Please identify the date each analysis was originally prepared.

RESPONSE:

El Paso Electric Company ("EPE") did not prepare any customer impact analyses that separately identifies or evaluates the impact of EPE's proposed change in the definition of summer season, the increase in the seasonal price differential, and increase in the price differential between the first and second energy blocks for summer for the Residential Service rate.

The following analysis, filed in this proceeding, provide the impact to the Residential Service monthly bills at varying levels of consumption:

- Petition Exhibit C (prepared 5/29/2021),
- Schedule Q-8.9 (prepared 5/30/2021), and
- Exhibit MC-7 (prepared 5/30/2021).

Preparer:	Manuel Carrasco	Title:	Manager – Rate Research
Sponsor:	Manuel Carrasco	Title:	Manager – Rate Research

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
OFFICE OF PUBLIC UTILITY COUNSEL'S
SEVENTH REQUEST FOR INFORMATION
QUESTION NOS. OPUC 7-1 THROUGH OPUC 7-12

OPUC 7-11:

Please provide any customer communication plans that EPE has developed to fully inform Residential Service customers of the proposed changes to the summer season definition, increase in the summer-winter seasonal price differential and increase in the price differential between the first and second summer energy blocks, if the proposed changes or a version of the proposed changes are approved.

RESPONSE:

El Paso Electric Company ("EPE" or "Company") has not to date developed communications for Residential Service customers that would be used following Commission approval of EPE's rate proposals. Following an order approving the changes to the seasonal definitions and prices, EPE would use the following mediums to communicate the changes prior to the summer season:

- Press Release
- Media
- Podcast
- Website
- Social Media
- Email
- Bill Inserts

All information regarding the tariff changes will be provided in both English and Spanish.

Preparer:	James Schichtl	Title:	Vice President – Regulatory and Governmental Affairs
Sponsor:	James Schichtl	Title:	Vice President – Regulatory and Governmental Affairs

Office of Public Utility Counsel's
Analysis of
Annual kWh per Customer by Customer Groups
Actual 2020 to Actual 2015-2019

Customer Group	2015	2016	2017	2018	2019	2020	Change from 2015-2019 Average	Change from 2019
Residential Service	7,614	7,658	7,582	7,902	7,831	8,611	11.59%	9.97%
Small General Service	10,633	10,928	11,057	11,058	10,099	10,155	-5.58%	0.56%
Lighting Services Rates	58,447	58,409	58,760	57,737	54,598	54,201	-5.89%	-0.73%
Municipal Pumping	397,377	378,029	381,899	409,588	448,181	430,454	6.81%	-3.96%
Water Heating Rider	1,247,236	1,202,579	1,004,709	898,570	945,023	812,411	-23.33%	-14.03%
General Service	226,167	229,594	226,394	228,919	214,199	203,738	-9.47%	-4.88%
Agricultural Rates	49,102	48,499	46,634	47,093	47,818	39,157	-18.13%	-18.11%
Large Commercial & Industrial Rates	12,214,186	12,154,576	12,375,457	12,982,946	11,955,083	11,445,251	-7.22%	-4.26%
Military Service	324,247,612	322,571,569	320,853,363	315,788,567	322,575,805	336,676,278	4.82%	4.37%
City & County	283,166	296,936	293,331	300,031	290,211	235,713	-19.48%	-18.78%
Total Texas Retail	19,987	19,831	19,512	19,727	19,231	19,197	-2.35%	-0.18%

WORKPAPERS

PROVIDED

ELECTRONICALLY

The following files are not convertible:

Attachment EDE-8.xlsx
Attachments EDE-2 3 and 5 Workpapers.xlsx
Attachment EDE-13 Workpapers.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.