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Received - 2021-11-19 01:25:51 PM
Control Number - 52195
ItemNumber - 395

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

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

CROSS REBUTTAL TESTIMONY

OF

CLARENCE L. JOHNSON

ON BEHALF OF

THE CITY OF EL PASO

NOVEMBER 19, 2021

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

CROSS REBUTTAL TESTIMONY OF CLARENCE JOHNSON

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I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Clarence Johnson. My address is 3707 Robinson Avenue, Austin, Texas 78722.

Q. ARE YOU THE SAME CLARENCE JOHNSON WHO PREVIOUSLY TESTIFIED IN THIS PROCEEDING ON BEHALF OF THE CITY OF EL PASO?

A. Yes.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I will respond to testimony presented by other parties in this proceeding. My testimony rebuts witnesses for Texas Industrial Energy Consumers ("TIEC"), University of Texas-El Paso ("UTEP"), Freeport-McMoRan Inc. ("FMI"), the Rate 41 Group, Office of Public Utility Counsel ("OPUC"), Vinton Steel, LLC("Vinton") and the Public Utility Commission Staff ("Staff"). My testimony focuses on selected issues, and the

omission of any issue in this testimony should not be construed as agreement or acceptance with another party's position on that issue.

Q. PLEASE SUMMARIZE YOUR TESTIMONY RECOMMENDATIONS.

A. My findings and conclusions are summarized below.

- The recommendations of Mr. Pollock, Ms. Pevoto, and Mr. Higgins to change the load factor in the production demand average and excess formula should be rejected.
- The recommendation of Mr. Higgins to allocate contributions and donations on a customer basis should be denied.
- The recommendations of Ms. Pollock and Mr. Higgins to change the allocation of production O&M expense are not well-supported and should be rejected.
- Mr. Higgins' proposal to exempt certain high voltage customers from transmission revenue requirement recovery associated with 69 kV facilities is unreasonable.
- The recommendations of Mr. Higgins and Mr. Pollock to change the allocation of production and transmission load dispatch expense is not consistent with cost causation and should be rejected.
- The class revenue distribution recommendations of Mr. Pollock, Mr. Daniel, Mr. Higgins, and Ms. Pevoto are unreasonable and place an excessive burden on residential customers, even though residential allocators were inflated due to COVID-19 impact.
- The recommendations of some parties ignore or understate the extraordinary impact of COVID-19 on the reliability of the Class Cost of Service Study (CCOS).
- The PUC Staff's proposal to increase the residential DG minimum bill is unreasonable and should be rejected.

II. PRODUCTION DEMAND CLASS ALLOCATION

Q. DO ANY WITNESSES PROPOSE CHANGES IN THE PRODUCTION DEMAND ALLOCATION METHOD APPLIED TO RETAIL CLASSES?

A. Yes. Mr. Higgins, Mr. Pollock, and Ms. Pevoto propose changes to the load factor used in the Average & Excess Demand-4CP (AED-4CP) formula. The three witnesses recommend the use of 1-CP instead of 4 CP as the measure for calculating load factor in the formula.[1] The Company utilized 4 CP as the basis for developing the load factor in the AED/4CP formula. Although the load factor input may appear to be a minor detail in the AED formula, modifying the load factor as proposed by the three intervenor witnesses will shift millions of dollars among the customer classes.

Q. DO YOU DISAGREE WITH THE RECOMMENDATION OF MR. HIGGINS, POLLOCK, AND MS. PEVOTO?

A. Yes. As stated in my initial testimony, the load factor should be calculated on the basis of the four-summer month average peak demand, rather than one-month peak demand.[2] Because AED-4CP utilizes the four-summer month average peak demand to represent class peak demands, the 4CP load factor matches the underlying measure of peak demand. Therefore, I agree with the load factor utilized by the Company to develop the AED-4CP method in this case.

[1] Load factor is "Peak Demand divided by Average Annual Demand," where Average Annual Demand is annual energy use divided by total annual hours (i.e., 8760), and Peak Demand is the measure of expected peak hour use.

[2] The load factor is the ratio used to divide the contributions of demand and average energy to the end result of the AED-4CP formula.

Q. WHAT IS THE MOST IMPORTANT REASON TO REJECT THE CHANGES TO THE AED-4CP PROPOSED BY THE THREE INTERVENOR WITNESSES?

A. Simply put, inserting the 1CP load factor into the AED-4CP formula causes the methodology to produce results outside of a reasonable range. Mathematically, so long as the load factor and measure of peak demand are synchronized, a coincident peak based Average & Excess formulas will tend to produce results within a narrow range. However, applying a 1 CP load factor to a 4CP based AED formula frequently leads to unreasonable results. The NARUC Cost Allocation Manual (CAM) states that the objective of an Average & Excess method is to "reflect the impact of average demand on production plant costs."[3] Given that the formula combines demand and energy, one would expect a class's AED allocation factor to fall in a range between the demand factor and the energy (average demand) factor for the class. The AED-4CP method with a 1 CP load factor fails this threshold test of reasonableness. The AED-4CP method as filed by the Company reflects a small contribution from the average demand component, but it largely produces (as expected) an allocation factor within the range bounded by the 4CP allocation factor and the average demand allocation factor. This is most apparent in comparing the low load factor residential class with the high load factor industrial classes. The comparisons below show the AED-4CP factor in the middle column between the 4 CP factor and the Average Demand factor.[4]

AED Factors

[3] NARUC CAM at 50.
[4] See, Direct Testimony of Jeffrey Pollock Schedule P-7 Errata 2 and Ex. JP-2, which presents Mr. Pollock's AED-4CP.

1CP Load Factor

Rate	4 CP Demand	AED 4CP	Avg Demand
01 Res	55.228%	55.555%	42.248%
15 Elec. Ref.	0.518%	0.506%	0.695%
25 LPS	6.872%	6.655%	10.302%
26 Pet. Ref.	2.770%	2.635%	5.090%

AED Factors
4CP Load Factor

	4 CP Demand	AED 4CP	Avg Demand
01 Res	55.228%	54.510%	42.248%
15 Elec. Ref.	0.518%	0.521%	0.695%
25 LPS	6.872%	6.942%	10.302%
26 Pet. Ref.	2.770%	2.828%	5.090%

Q. PLEASE EXPLAIN WHY THE AED-4CP (1 CP LOAD FACTOR) ALLOCATION FACTORS ILLUSTRATE AN UNREASONABLE RESULT.

A. In the AED-4CP (1 CP load factor) table, the allocation factor for the residential class is higher than either the 4 CP or Energy (average demand) allocation factors. For the three high load factor industrial classes, the AED-4CP (1 CP load factor) allocation is less than either the 4 CP or Energy (average demand) allocation factors. By contrast, in the Company's AED-4CP formulation, the AED-4CP factor for the three high load factor classes and the residential class falls within the range bounded by the 4 CP and Energy (average demand) allocation factors.

Q. MR. HIGGINS STATES THAT THE 1 CP LOAD FACTOR IS SUPPORTED BY THE NARUC COST ALLOCATION MANUAL (CAM). DOES THIS JUSTIFY THE USE OF 1 CP LOAD FACTOR IN THE AED-4CP?

A. No. The NARUC CAM does not include or describe the AED-4CP method. The CAM's description of the Average & Excess method is based upon AED-NCP. The NARUC CAM states that the Average & Excess method should utilize Non-Coincident Peak (NCP[5]) demand to measure class demands and advises against the use of coincident peak demands in the AED. Normally NCP demand reflects the single month peak for each class. In that context, load factor based on a single month peak is consistent with the underlying measure of class demands. Similarly, 4 CP load factor matches the 4 CP class demands used in the AED-4CP method.

Q. MR. HIGGINS AND MS. PEVOTO CONTEND THAT THE 1 CP LOAD FACTOR IS CONSISTENT WITH THE COMPANY'S METHOD OF ASSESSING LOADS AND RESOURCES FOR RESERVE MARGIN PURPOSES. DO YOU AGREE?

A. No. This oversimplifies the planning process. The development of the target reserve margin (expressed as a MW percentage of loads or resources) is based on an analysis of the probability of a loss of load for many hours during the year, taking into account multiple factors (such as potential resource outages and interconnection constraints) in addition to the forecasted peak.[6] Mr. Higgins' argument is contradicted by the use of 4 CP in the AED-4CP method. 4 CP, rather than 1 CP, is used to measure peak demand because the system peak could occur in any of the four summer months. The same reasoning is applicable to the load factor component.

[5] Noncoincident demand is the sum of two or more individual group(class) demands which do not occur at the same demand interval.

[6] This description is consistent with Mr. Novela's explanation of the planning process at 9-10 of his direct testimony. Direct Testimony of EPE Witness George Novela

Q. MR. POLLOCK, MR. HIGGINS. AND MS. PEVOTO STATE THAT COMMISSION PRECEDENT SUPPORTS THEIR RECOMMENDATION. DOES THIS ALTER YOUR OPINION?

A. No. The development of an AED-4CP formula should be based on the facts specific to each case. They cite SPS and SWEPCO, which are governed by the Southwest Power Pool's (SPP) planning requirements; EPE is not. On its face, the Commission's decision in Docket No. 43695 is based on facts specific to the that case. The order cites as its basis the Southwestern Power Pool (SPP) capacity margin requirement applicable to SPS, and relies upon the deposition testimony of SPS's cost allocation witness.[7] This contrasts with the facts presented in this case. EPE's Director of Economic Research filed testimony stating that the 4CP load factor is not inconsistent with the probabilistic determination of forecasted peak demand in the planning process. Furthermore, El Paso Electric Company is subject to the Western Electricity Coordinating Council (WECC). The WECC analyzes system reliability and the potential for generation reserve margin deficiencies based on many hours, not one hour, in a year. The WECC examines reliability on both monthly and annual bases and evaluates different peak demand scenarios using varying weather parameters.

Q. HAS WECC RECENTLY ADVISED ITS MEMBERS THAT APPROPRIATE GENERATION RESERVE MARGINS SHOULD NOT BE BASED ON A SINGLE PEAK HOUR?

[7] *Application of Southwestern Public Service Co. for Authority to Change Rates*, Docket No. 43695, Order at 11, FOF 246A and 251A.

A. Yes. WECC's Resource Adequacy Assessment advises its members that traditional methods of resource planning will not be adequate in the future.[8] According to WECC, if the current generation planning methods are not changed to reflect dynamic reserve margins across many hours, resource adequacy will be seriously degraded.[9] WECC describes the traditional approach as a "deterministic approach to resource planning, [that] identifies the peak demand hour, [and] applies a flat fixed reserve margin."[10] WECC states that the assumption of this approach—that resources are adequate in all hours so long as the reserve margin in adequate in the annual peak hour—is no longer acceptable. WECC concludes that demand and resource variability in the western region requires member utilities to assess resource adequacy for hours throughout the year.[11]

Q. MS. PEVOTO CITES DOCKET NO. 40443 TO SUPPORT HER RECOMMENDED USE OF UNADJUSTED LOAD FACTOR DATA. IS THIS DECISION SUPPORTIVE OF HER RECOMMENDATION TO USE THE 1 CP LOAD FACTOR?

A. No. The order in Docket No. 40443 adopted the following finding of fact no. 284:

The system load factor is calculated based on the annual energy use and four coincident peaks.[12]

[8] Western Assessment of Resource Adequacy Report, December 18, 2020 at 2. Western Electric Coordinating Council's annual assessment of its members' (including EPE) loads and resources for 2021.
[9] Ibid. at 4.
[10] Ibid.
[11] *Ibid.*
[12] *Application of Southwestern Electric Power Co. for Authority to Increase Rates,* Docket No. 40443, Order on Rehearing, FOF 284.

Q. DID MR. POLLOCK'S TESTIMONY IN DOCKET NO. 40443 RECOMMEND THE USE OF A 4 CP LOAD FACTOR?

A. Yes. Mr. Pollock's testimony, without any reservation, stated "Specifically, the load factor used to weight the average demand component of the A&E-4CP should be based on SWEPCO's system-wide 4 CP load factor (58%) rather than the firm Texas Retail load factor (65%), which both SWEPCO and Mr. Abbott used."[13]

Q. MS. PEVOTO'S TESTIMONY DISCUSSES HER RECOMMENDATION THAT UNADJUSTED DATA SHOULD BE USED FOR THE LOAD FACTOR. DO YOU OBJECT TO USING UNADJUSTED DATA TO CALCUATE A 4 CP LOAD FACTOR?

A. Not in this case. The difference between a 4 CP load factor based on adjusted vs. unadjusted data is relatively minor. The Company's adjusted 4 CP load factor is 48.7%, and the unadjusted 4 CP load factor is 48.9%.

Q. WHAT IS YOUR CONCLUSION?

A. The Commission should reject recommendation of TIEC, FMI, and UTEP to adopt a 1 CP load factor in the AED-4CP.

III. CONTRIBUTION AND DONATIONS ALLOCATION

Q. WHAT IS THE RECOMMENDATION OF MR. HIGGINS REGARDING ALLOCATION OF CONTRIBUTIONS AND DONATIONS?

[13] Cross Rebuttal Testimony of Jeffry Pollock at 7, Docket No. 40443. (Item 770 1-10-2013)

A. Mr. Higgins recommends a customer allocation for contributions and donations, instead of a labor allocation. According to Mr. Higgins, the CCOS amount for contributions and donations expense is included in FERC Account 930.2 (miscellaneous general expense). However, FERC Account 930.2 also includes other expense items, including industry dues, industry research activities, publishing and distributing the corporate annual report, director fees, and annual meeting expenses.[14] The Company records $3.595 million in FERC Account 930.2.[15] Given that the Company's allowable contributions and donations amount is only $1.2 million, a change to the allocation of Account 930.2 would affect more than contributions and donations. As an additional note, EPE recently indicated its intent to withdraw its request to recover contributions and donations in cost of service. If the Company in fact withdraws the request in its rebuttal testimony, this allocation issue is moot.

Q. DO YOU AGREE WITH MR. HIGGINS' PROPOSED ALLOCATION?

A. No. A customer allocation represents an unreasonably narrow allocation basis for these costs. My testimony recommended a Net Plant allocation for FERC Account 930.2 because it is a reasonable allocator for indirect corporate, shareholder, and industry expenses included in this account. I did not use the Company's labor allocation for this account, given the deficiencies in the labor allocation discussed in my direct testimony. However, the Company's labor allocation of this account is preferable to the narrow customer allocation recommended by Mr. Higgins.

[14] FERC chart of accounts description for Account 930.2.
[15] EPE Rate Filing Package Schedule P-4 and Schedule A-3.

Q. MR. HIGGINS STATES THAT THE CUSTOMER ALLOCATION IS APPROPRIATE BECAUSE IT BEST REFLECTS "A WIDE DISPERSION OF BENEFITS." DO YOU AGREE?

A. No. I agree that the appropriate allocator should reflect a wide dispersion of benefits. But the customer allocator is the narrowest allocation method available, and therefore does not meet this criterion. The customer allocator assigns almost 90% of the cost to one customer class (residential). This allocator does not spread costs widely across customer classes. The customer allocator is appropriate only for expenses which are closely correlated with number of customers. By Mr. Higgins' own criteria, a customer allocator is inappropriate for contributions and donations.

IV. ALLOCATION OF PRODUCTION O&M EXPENSE

Q. DO YOU AGREE WITH CHANGES IN CLASSIFICATION OF PRODUCTION O&M EXPENSES PROPOSED BY MR. POLLOCK AND MR. HIGGINS?

A. No. The Company historically has classified production O&M expense in accordance with guidance of the NARUC CAM. In this case, the Company refined the classification to make the overall result more consistent with the NARUC CAM. Mr. Pollock states an intent to change the steam production accounts 502 and 505 to partial demand based on the percent labor expense and proposes a 100% demand classification for the following nuclear production accounts, 519, 520, and 523. Mr. Higgins proposes to classify all nuclear non-fuel expense as demand. My recommendation is to reject Mr. Pollock's and Mr. Higgins' proposed changes in classification.

Q. IS MR. POLLOCK CORRECT IN HIS CONCLUSION THAT EPE DID NOT PROPERLY CLASSIFY STEAM PRODUCTION EXPENSE ACCOUNTS 502 AND 505?

A. No. His is mistaken in his review of the Company's classification of these accounts. The Company has classified the labor expenses in these accounts on the basis of demand. As shown on Schedule P-04, the Company separated both accounts into labor and non-labor sub-accounts and classified the labor sub-accounts on the basis of demand.[16] Therefore, Mr. Pollock's proposed change to this account is mistaken.

Q. PLEASE DISCUSS MR. POLLOCK'S PROPOSAL TO CHANGE NUCLEAR ACCOUNTS 519, 520, AND 523 TO 100% DEMAND.

A. Mr. Pollock provides no evidence to support this change. If EPE is unable to perform a labor proration of these accounts, there is no reason to believe that the default classification should be demand. Mr. Pollock acknowledges that the accounts could be classified on the basis of the dominant cost in the accounts, but he does not explain why these accounts would be dominated by labor. In fact, the selected accounts (Nuclear Coolants and Water, Nuclear Steam, and Nuclear Electric) are known to involve large components of materials and consumables which vary with kWh generation. Moreover, Mr. Pollock has not proposed a consistent application of the NARUC CAM labor proration method, which would result in the classification of more production O&M expense as energy-related. Some portion of supervision and

[16] EPE Rate Filing Package Errata 2 Schedule P-04. (Item 221 Filed 10-1-2021)

engineering accounts (500, 510, 517, 528) would have been classified as energy-related.[17]

Q. PLEASE EXPLAIN YOUR DISAGREEMENT WITH MR. HIGGINS' PROPOSAL TO CLASSIFY ALL NUCLEAR NON-FUEL EXPENSES AS 100% DEMAND.

A. Because EPE is operated by Arizona Public Service, Mr. Higgins contends that the nuclear O&M expense should be treated as fixed pass-through expense. However, labeling the expense as a "pass through" ignores the fact that EPE is part owner of Palo Verde and is directly involved in the supervision and oversight of Palo Verde operations. Moreover, calling it a pass through does not make it a fixed expense. The Palo Verde expense amounts vary from year to year. The NARUC CAM recognizes that nuclear operations accounts contain materials and consumables that tend to vary with kWh generation. Moreover, the CAM classifies most nuclear maintenance expense as variable because the cost is required to address wear and tear of equipment, which varies over the long term with hours of usage. Most planned maintenance is scheduled based on hourly duration of operation. Thus, the underlying annual expense charged to EPE will vary in amount. Finally Mr. Higgins' recommendation would change EPE's historic allocation of Palo Verde expense, resulting in a significant and unreasonable shift in the distribution of these expenses among customer classes.

[17] NARUC CAM at 38, footnote 3: These accounts should be classified on the basis of labor/material percentages of the underlying accounts in the group. EPE applied 100% demand.

V. LOAD DISPATCH EXPENSE

Q. DOES ANY WITNESS PROPOSE A CHANGE TO THE ALLOCATION OF LOAD DISPATCH EXPENSE?

A. Yes. Mr. Pollock and Mr. Higgins object to the 12 CP allocation methods that the Company applies to production and transmission load dispatch expense. They both propose to apply the AED-4CP allocation factor to load dispatch expense.

Q. DO YOU AGREE?

A. No. Load dispatch benefits all hours of the year and should be allocated on either a 12 CP or average demand basis. As noted above, the Company utilized 12 CP.

Q. WHAT IS LOAD DISPATCH?

A. Load dispatch is the process of tracking real time electricity demand and dispatching a cost-effective combination of generation resources to match customer usage. Because changes in real time demand vary on a locational basis, this process involves transmission and distribution operations, in addition to production personnel. Load dispatch incorporates a multitude of information in making dispatch decision, including generating plant availability, incremental costs for each generating plant, the status of transmission and distribution constraints, current and forecasted weather conditions, and real time demand in various parts of the service area.

Q. DO ANY COMMISSION DECISIONS ADDRESS THE APPROPRIATE ALLOCATION OF LOAD DISPATCH?

A. This issue was subject to contested litigation in SPS Docket No. 43695. In that case, SPS allocated production load dispatch based on 12 coincident peak demand (12 CP), and transmission and distribution dispatch expense based on average demand. Several

intervenor witnesses contested the SPS allocation, proposing the same recommendation that Mr. Pollock and Mr. Higgins present in this case. The Commission found that SPS' allocation was reasonable. The PFD in that case points out that "it is without question that load dispatching occurs every hour of every day," and goes on to state, "peak demand does not occur nearly as often as typical average demands, and that the peak demand usages are included in each class's average demand over the course of a year."[18] The PFD concludes that 12 CP is a "reasonable balance" for production load dispatch.

Q. WHY DO MR. HIGGINS AND MR. POLLOCK FAVOR THE D-1 ALLOCATOR FOR LOAD DISPATCH?

A. Both witnesses prefer the AED-4CP method because it focuses on the 4 summer month peak demand. However, this view ignores the fact that load dispatch is necessary to meet load in every hour of the year.

Q. MR. HIGGINS SAYS THAT LOAD DISPATCH IS MORE CHALLENGING DURING THE 4 SUMMER PEAK HOURS. IS THIS A REASONABLE BASIS FOR CONFINING THE ALLOCATION TO A 4 CP BASED METHOD?

A. No. Mr. Higgins provides no real evidence to support his assumption that load dispatchers work more intensively during the summer peak hours. Also, this ignores the fact that EPE's only negative reserve margin in 2021 occurred during an hour in February. This serious condition surely was one of the most challenging conditions

[18] *Application of Southwestern Public Service Co. for Authority to Change Rates*, Docket No 43695, Proposal for Decision at 246 – 247. (Item 970 10-12-2015)

faced by EPE's load dispatch. Yet his allocation would assign no load dispatch expense to the February load.

Q. MR. POLLOCK CONTENDS THAT WHETHER AN EXPENSE IS A YEAR-ROUND ACTIVITY IS IRRELEVANT TO COST CAUSATION. DO YOU AGREE?

A. No. With respect to load dispatch expense, it's hard to imagine a characteristic that is more relevant to cost causation. Load in every hour of the year benefits from load dispatch. If load dispatchers are unable to properly match minute-to-minute demand with available electrical supply, the result could be disastrous. As discussed above, the reserve margin issue in February 2021 exemplifies the importance of load dispatch outside the four summer months.

Q. WHAT IS YOUR RECOMMENDATION?

A. No changes should be made to the Company's allocation of load dispatch expense.

VI. TRANSMISSION CLASS ALLOCATION

Q. PLEASE DESCRIBE TIEC'S RECOMMENDATION TO CHANGE THE ALLOCATION OF TRANSMISSION COSTS AMONG CUSTOMER CLASSES.

A. Mr. Higgins proposes to exclude 115 kV customer classes from the allocation of 69 kV transmission costs in the CCOS. Under the Company's proposal, transmission revenue requirement is allocated among customer classes based on the class contribution to 4 CP demand. Mr. Higgins proposal would deduct the cost of 115 kV transmission facilities from transmission revenue requirements so that the classes connected at

higher voltage do not share in the cost of 69 kV transmission facilities. His recommendation is that these customers should only share the cost of 115 kV lines.

Q. DO YOU AGREE WITH HIS PROPOSAL?

A. No. Although he refers to his recommendation as added "granularity," the proposal departs from the principle of average cost pricing of network transmission service.

Q. IS THIS RECOMMENDATION DISTINGUISHABLE FROM RECOGNIZING THE EFFECT OF VOLTAGE DIFFERENTIALS ON ENERGY LOSSES?

A. Yes. It is not unusual for the CCOS allocation factors to reflect differing energy losses based on the voltage that the customer takes energy. This is a procedure for converting energy output at the source to billing determinants at the meter. But voltage differentiation of losses is quite different from changing the revenue requirements allocated to particular classes based on the voltage of transmission equipment.

Q. WHY IS MR. HIGGINS' PROPOSAL UNREASONABLE?

A. The transmission system is operated as a network, and the allocation of costs should reflect the fact that all customers benefit from the network. The Commission has previously recognized that transmission systems are operated as a network. The Commission rejected proposals which departed from average cost pricing of total transmission revenue requirements in ERCOT: "the Commission concluded that in many respects, the ERCOT transmission system acts as single network that all the customers use."[19] In Docket No. 43695, the Commission pointed to the pooling of

[19] Project No. 21080, Amendment to PUC Subt. R. 25.192, Preamble at 13, issued Dec. 6, 1999.

transmission costs in ERCOT as the traditional method for allocating transmission costs in Texas, and ordered SPS to allocated radial transmission lines to all customers.[20]

Q. DOES MR. HIGGINS' PROPOSAL TREAT DIFFERENT TYPES OF TRANSMISSION CUSTOMERS IN A COMPARABLE MANNER?

A. No. To the extent that any portion of the 115 kV facilities primarily serve 115 kV customers, Mr. Higgins' proposed allocation of 115 kV facilities does not reflect an increased responsibility for the highest voltage customers. However, because 69 kV facilities directly serve customers at or below that voltage, he increases the allocation of 69 kV facilities to those customers. Moreover, EPE's FERC open access tariff for wholesale transmission customers is also based on average cost pricing. EPE's FERC approved network service transmission rate is based on *total* transmission revenue requirements. FERC requires that EPE's wholesale transmission rates are comparable to the Company's transmission rates for serving native load. EPE also utilizes network transmission service to serve its retail customers, which is based on average cost pricing.

Q. SETTING ASIDE THE CONCEPTUAL OBJECTIONS TO MR. HIGGINS' TESTIMONY, DO OTHER REASONS EXIST TO REJECT HIS PROPOSAL?

A. Yes. Mr. Higgins admits that the Company is unable to separate the recorded embedded costs of 69 kV transmission facilities from the overall transmission net plant costs. Instead, Mr. Higgins utilizes a Company estimate based on the ratio of 69 kV line miles to total system circuit miles. However, the accuracy of this method has not been

[20] Order on Rehearing at 46, FOF 259A and 260A, *Application of Southwestern Public Service Co. for Authority to Change Rates*, Docket No. 43695. (2-23-2016)

demonstrated, and the overall approach requires several problematic assumptions. A circuit mile comparison requires an assumption that cost per unit of lines, poles, and towers are the same for lower voltage facilities and high voltage facilities. Inasmuch as higher voltage facilities require larger lines and heavier duty poles and towers for safety reasons, this assumption is likely to be wrong. Moreover, this method does not recognize the actual costs of the 69 kV facilities, which would be based on the as spent cost and vintage of equipment. Therefore, Mr. Higgins' attempt to separate 69 kV transmission revenue requirements is not sufficiently accurate to support a change in the CCOS.

VII. REVENUE DISTRIBUTION

Q. WHAT IS THE CONTEXT FOR THE CLASS REVENUE DISTRIBUTION PROPOSALS IN THIS CASE.

A. The CCOS study prepared by EPE is dependent on energy and demand allocation factors which are based on class electricity usage during the 2020 test year. As described in both my direct testimony and the direct testimony of EPE's cost allocation witness, the COVID-19 pandemic caused dramatic changes in demand and energy usage among residential, commercial, and industrial classes. The COVID pandemic is unique in U.S. history and resulted in economic impacts during the second quarter of 2020 which are unparalleled in the domestic economy. Beginning in Q2 2020, a portion of workplace electricity use was shifted from businesses and industrial locations to

residential dwellings. During 2020, compared to the average of the prior three years, EPE's residential class experienced energy and demand allocation factor increases of 12% and 21%, respectively[21]. During 2020, compared to the average of the prior three years, the aggregate of EPE's Small General Service Rate 02 (SG), General Service Rate 24 (GS), Large Power Service Rate 25 (LPS), Petroleum Refining Service Rate 26 (P), and City-County Rate 41 experienced energy and demand allocation factor decreases of 10% and 18%, respectively.[22] In recognition of this unusual situation, EPE's proposed revenue distribution placed a 150% cap on the residential class revenue increase, and reduced the magnitude of class revenue reductions indicated by the CCOS study. My direct testimony evaluated the Company's revenue distribution constraints by normalizing the class allocation factors used in the CCOS study for the classes above, based on a three-year average, and concluded that EPE's proposed constraints are inadequate to mitigate COVID-19 impact on the CCOS study.

Q. PLEASE DISCUSS THE OTHER PARTIES' RESPONSE TO THE COMPANY'S PROPOSED CLASS REVENUE INCREASE.

A. Mr. Stanley, Mr. Daniel, and Mr. Higgins ignore EPE's stated position that its rate moderation constraints are due to COVID-19 impacts. Mr. Pollock acknowledges the Company's position, but contends that the aberrations caused by COVID-19 should be ignored in the class revenue distribution. Mr. Pollock's and Mr. Higgins' position is that class revenues should be set at cost. Mr. Daniel contends that the Company's method for applying a "floor" (50% times indicated class revenue decrease) results in

[21] Calculated from Direct Testimony of El Paso Electric Witness Manuel Carrasco Exhibit MC-5.
[22] Calculated from Exhibit MC-5.

a double subsidy of classes which receive revenue decreases. Mr. Stanley proposes to extend the Company 150% cap on residential revenue increases to all classes. Ms. Pevoto's position regarding COVID-19 impact is less clear. Initially she states that COVID-19 impact is "speculative" and that rate moderation should not be based upon speculation.[23] However, she concedes that COVID-19 produced "atypical" results for some rate classes, and proceeds to develop rate moderation constraints to address the COVID-19 impact on classes.[24] Ms. Pevoto's rate moderation mechanism result in significantly higher residential revenues and higher residential increase than the Company proposed.[25] Mr. Evans opined that COVID-19 affected all customer classes, and recommended a 150% cap and 50% floor based on the Texas retail percent increase. The schedules and rate calculations prepared by PUC Staff witness Narvaez purportedly accept the Company's rate moderation constraints. [26] However, his testimony does not discuss the rate moderation constraints underlying his schedules.

Q. DO YOU AGREE WITH PARTIES WHO CONTEND THAT COVID-19 IMPACTS ON THE CCOS STUDY SHOULD BE IGNORED?

A. No. The COVID-19 pandemic is virtually the definition of exceptional circumstances. The impact produces CCOS allocation factors which are clearly anomalous and unrepresentative of both past and future usage patterns for the major rate classes. Ignoring this fact is equivalent to saying that the CCOS study results must be accepted without regard to the validity of the data which supports it. Mr. Pollock, Mr. Higgins,

[23] Direct Testimony of Kit Pevoto for UTEP at 24.
[24] Pevoto direct at 25.
[25] Pevoto direct at 29, Table KP 8 ($42,898,000 increase to residential class)
[26] PUC Staff Response to CEP Request No. 1-3.

and Ms. Pevoto refer to previous PUC decisions which favor class revenue distribution that adheres to the CCOS study result. But those prior decisions did not involve the extraordinary impact of the COVID pandemic. In view of the aberrant data caused by the pandemic, I do not agree with a "business as usual" approach to the class revenue distribution.

Q. MR. POLLOCK CLAIMS THAT COVID-19 IMPACT ON CLASS USAGE CAN BE IGNORED BECAUSE INCREASES OR DECREASES IN ELECTRIC USAGE WILL BE ACCOMPANIED BY CHANGES IN CLASS ANNUAL REVENUES. DO YOU AGREE THAT ABERRATIONS IN ALLOCATION FACTOR DATA CAN BE SAFEY IGNORED?

A. No. The logical conclusion of Mr. Pollock's argument is that the validity or acceptability of the data used to develop allocation factors will not affect the accuracy or validity of the CCOS study results. That conclusion is contrary to the rationale for conducting a CCOS study. The foundational concept of a CCOS study is that class responsibility for cost causation can be determined by applying each class' appropriate and accurate percentage share of various demand, energy, and customer allocation factors to thousands of utility cost elements. If the allocation factors are based on anomalous, aberrant, and non-representative data, then the CCOS study produces unreliable or useless results "garbage in; garbage out." I agree that changes in class usage will also produce changes in test year present revenues. For that reason, my evaluation of an adjusted CCOS study result included both allocation factor adjustments for six classes *and* a reduction in present revenues for the residential class

accompanied by an equivalent increase in revenues for the five other classes.[27] However, my evaluation of the adjusted CCOS study in no way supports Mr. Pollock's position that the revenues generated by each class compensates for flawed allocation factors.

Q. MR. POLLOCK'S EX. JP-8 COMPARES CLASS REVENUES AND ENERGY IN THE DOCKET NO. 46831 SETTLEMENT WITH THE ADJUSTED CLASS REVENUES AND ENERGY IN THIS CASE. DOES THIS SHOW THAT THE CHANGE IN CLASS REVENUES SOMEHOW CORRECTS COVID IMPACTS ON THE CCOS STUDY?

A. No. The revenue comparison presented by Mr. Pollock simply does not support his position that the class impacts of COVID-19 are somehow self-correcting. For example, SGS and GS classes were obviously impacted by COVID-19 due to business restrictions. Ex. JP-8 indicates that SGS and GS incurred revenue growth of 1% and 0% since Docket No. 46831. However, Ex. MC-5 shows that SGS and GS demand allocation factors decreased by 29% and 25%, respectively, since 2017. The combination of deep reductions in the two classes' demand allocation factors accompanied by no reduction or a slight increase in the class present revenues would compound the level of class revenue reductions indicated by the CCOS study. Based on Ex. JP-8, the change in base revenues for SGS and GS actually magnifies the impact of the aberrant allocation factors. Thus, Mr. Pollock's revenue comparison does not support his position that COVID-19 has no impact on the CCOS study results.

[27] See, Attachment B to my direct testimony.

Q. DOES THE COMPARISON IN EX. JP-8 PROVE THAT BASE REVENUES MOVE IN LOCK STEP WITH CHANGES IN ALLOCATION FACTORS?

A. No. Several problems arise in using this comparison. First, the changes in base revenues since 2017 are driven by intervening rate changes (such as the TCRF and DCRF) as well as usage changes. Thus, this is not an apples-to-apples comparison of energy growth and revenue growth. Second, Ex. JP-8 does not include all of the data relevant to allocation factors in the CCOS study. Mr. Pollock did not show comparisons for the different measures of demand used in the CCOS study. Generally, the percentage change in class demand allocation factors was more significant than energy allocation factors. Third, changes in class load factor will affect whether class base revenues track changes in usage. Available evidence indicates that the temporary impact of COVID-19 restrictions affected the load shape and load factor of some classes. Fourth. a comparison based on each classes' change in kWh does not reflect the change in each classes' *allocation factors*. Accordingly, a change in one class' allocation factor is dependent on the relative change in other class' demands or energy. An error or flaw in one class's kWh or kW will distort the allocation factors for all classes. Therefore, the change in class costs will reflect the combined interaction of varied changes in classes' energy, demand, and customer billing determinants.

Q. MS. PEVOTO CLAIMS THAT THE COVID-19 IMPACT DISCUSSED IN EPE'S TESTIMONY IS 'SPECULATIVE' AND OBJECTS BECAUSE EPE CANNOT PREDICT WHEN ALL COVID-19 IMPACTS WILL DISAPPEAR. IS THIS A VALID CRITICISM?

A. No. Factually we know that the most severe COVID-19 electric usage impacts occurred in 2020, and that impact of the pandemic on the economy has diminished considerably subsequent to 2020. The impact was most significant in the second quarter of 2020 (when business and employment restrictions were put in place), and the impact on EPE's residential usage began to decline after July 2020.[28] Therefore, the 2020 test year allocation factors are known aberrations. Some differences between the rate year and test year always exist. It makes no sense to refuse to correct known aberrations in the test year data because we cannot predict that the COVID-19 impact on rate year usage will be zero. The more reasonable approach is to normalize the test year allocation data based on historic experience similar to the approach in my direct testimony.

Q. MS. PEVOTO SUGGESTS THAT CLASS USAGE PATTERNS MAY NOT REVERT TO NORMAL BECAUSE WORK FROM HOME WILL BECOME A PERMANENT FEATURE. PLEASE RESPOND TO THIS ARGUMENT.

A. Ms. Pevoto has overstated the magnitude of this concern. The two major contributors to the increase in home electric usage arising from COVID-19 were: (1) Employees who shifted to working from home; and (2) Loss of employment because of business closure or business cutbacks. According to U.S. Bureau of Labor Statistics data, both impacts have steadily declined subsequent to the second quarter of 2020.[29] The combined impact as a percent of the adult work force declined from a peak of 55% in May 2020 to 13% in October 2021. The work from home (WFH) percentage in October

[28] Comparing 2020 and 2019 residential kWh usage by month, the "excess" of 2020 monthly usage over the same months in 2019 reached a peak of 21% in July 2020 and declined to an average of 10% from August – December 2020.

[29] https://www.bls.gov/cps/effects-of-the-coronavirus-covid-19-pandemic.htm#MayJune

2021 is less than one-third of the second quarter 2020 level. Monthly data intervals shown below illustrate the steady decline in COVID-19 impact.

	% Workers WFH Due to COVID19
20-May	35.4%
20-Aug	24.3%
20-Dec	23.7%
21-Apr	18.3%
21-Jun	14.3%
21-Oct	11.6%

	Percent Labor Force Unemployed Due to COVID Business Closures
20-May	19.2%
20-Sep	7.4%
20-Dec	6.1%
21-Apr	3.6%
21-Jun	2.4%
21-Oct	1.5%

Q. IF INHERENTLY FLAWED ALLOCATION DATA CANNOT BE CORRECTED EITHER THROUGH CCOS CHANGES OR RATE MODERATION, WHAT IS THE APPROPRIATE REMEDY?

A. As stated previously, the validity of allocation factor data is critical to the acceptance of the CCOS study. If the allocation data is flawed and cannot be used to represent future class usage patterns, the CCOS study should rejected, and equal percentage class revenue percentages applied in order to maintain current class relationships. For

example, in Docket No. 28813, the Commission rejected the reliability of data used for demand allocation factors, and, as a result, applied an across-the-board equal percent class rate increase.[30] As the Commission stated: "if the absolute demand data for one class is biased in a way that the data for other classes is not, then the relative demand data will be skewed."[31] My direct testimony relied upon an adjusted CCOS study to develop rate moderation constraints which are adequate to address the COVID-19 impact on allocation data. In my view, this is preferable to an across-the-board revenue increase. However, if other parties contend that the COVID-19 impact cannot be determined or addressed, the logical alternative is to reject the CCOS study and adopt an equal percentage change in class revenues.

Q. DO YOU AGREE WITH MR. STANLEY AND MR. EVANS THAT THE SAME RATE MODERATION CAP SHOULD BE APPLIED TO ALL CLASSES?

A. Yes. That general concept is consistent with my recommended revenue distribution. Several of the smaller non-residential classes which would otherwise receive large percentage increases may be indirectly affected by the COVID-19 impact. In addition, applying the cap in a uniform way is equitable.

[30] PUC *Petition to Inquire Into the Reasonableness of Cap Rock Energy Corp.'s Rates*, Docket No. 28813, Order on Rehearing, FOF No. 144 – 149. (11-10-2005, Item 2009)
[31] Ibid. FOF 145.

Q. DO YOU AGREE WITH THE REVENUE DISTRIBUTION PROPOSALS PRESENTED BY MR. HIGGINS, MR. POLLOCK, MS. PEVOTO, AND MR. DANIEL?

A. No. Each of the witnesses proposes to place an excessive burden on the residential class. Such an outcome is unreasonable, given that this customer class incurs the most significant harm from aberrant energy and demand allocation factors. Mr. Daniel recommends that the residential revenue increase be set at 205% of system average.[32] Ms. Pevoto recommends a 212% relative percent increase for residential.[33] Mr. Pollock's proposal results in a 282% relative percent increase for the residential class[34]. Mr. Higgins recommends a residential revenue increase at 293% of the system average.[35] By comparison, my recommendation sets the maximum cap at 140% of system average.

Q. ASIDE FROM THE COVID-19 ISSUE, ARE THERE OTHER REASONS IN THIS CASE TO AVOID THE EXCESSIVE RESIDENTIAL TIMES SYSTEM AVERAGE REVENUE INCREASES RECOMMENDED BY MR. HIGGINS, MR. POLLOCK, MS. PEVOTO, AND MR. DANIEL?

A. Yes. EPE's residential class in Texas is composed of an unusually high percentage of households in poverty. For low income families, the electricity bill comprises a larger proportion of the family's household budget, and can be a significant impediment to avoiding homelessness or paying basic expenses. 20.2% of El Paso County residents

[32] Direct Testimony of James Daniel Direct at 15. 15.16% / 7.38%.
[33] Pevoto Direct at 30. 15.68% / 7.38%.
[34] Direct Testimony of Jeffrey Pollock Direct at 78. 20.9% / 7.4%.
[35] Direct Testimony of Kevin Higgins Direct at 57. 20.7% / 7.06%.

have incomes below the poverty line. This is significantly higher than the average for Texas residents (13.6%). [36] El Paso has the 13th highest poverty rate compared to all large U.S. Cities. Given the financial condition of low income customers in the residential class, as a matter of policy the Commission should avoid large increases in EPE's residential rates.

VIII. DG RESIDENTIAL MINIMUM BILL

Q. DOES PUC STAFF WITNESS MR. ABBOTT ADDRESS THE RESIDENTIAL MINIMUM BILL FOR NON-GRANDFATHERED DISTRIBUTED GENERATION (DG)?

A. Yes. EPE proposed to reduce the residential DG minimum charge from $30 to $24.02. EPE also proposes to reduce the SGS DG minimum bill in a similar fashion. Mr. Abbott opposes the minimum bill reduction and recommends increasing the current minimum bill by the same percentage as the increase in overall residential revenues. He also proposes that the minimum bill should be maintained at $30 even if the Commission decreases overall residential revenues. His recommendation regarding the SGS minimum bill is the same.

[36] Federal Reserve Economic Data (FRED). https://fred.stlouisfed.org/series/PPAATX48000A156NCEN and https://fred.stlouisfed.org/series/S1701ACS048141.

Q. WHAT IS YOUR UNDERSTANDING OF THE PURPOSE OF THE DG MINIMUM BILL?

A. Residential DG primarily consists of rooftop solar. When the output exceeds the electric consumption of the residence, net metering reduces the billed kWh electricity. The concern is that a residential DG customer's monthly bill may be zero or negative in some months, resulting in no contribution to the costs of the distribution grid. The monthly minimum bill is intended to ensure that the DG customer pays a positive bill that recovers some of the residential class' distribution costs.

Q. DO YOU AGREE WITH MR. ABBOTT'S POSITION?

A. No. The current minimum bill is a settlement compromise. Some witnesses (including myself) testified in Docket No. 46831[37] that DG should pay no minimum bill, or at least a much smaller minimum charge. Mr. Abbott proposed higher minimum charges in the form of a per kW bill. The order in Docket No. 46831 did not make any specific findings that residential DG customers are subsidized, but rather adopted the settlement as a reasonable resolution of a controverted issue. Because Mr. Abbott continues to view the minimum bill as inadequate, he objects to the Company's proposed reduction. However, the $30 minimum bill is not an agreement as to the underlying cost position of the residential DG service. Based on its calculation of the change in average residential distribution demand costs since Docket No. 46831, EPE determined that the $30 minimum bill should be reduced. In my opinion, a minimum bill which is more than three times the standard residential customer charge runs the risk of posing a

[37] *Application of El Paso Electric Company to Change Rates*, Docket 46831

discriminatory barrier to entry by competitors.[38] Therefore, eliminating the minimum bill in its present form is a reasonable option. Absent the elimination of this charge, my conclusion is that EPE's proposed reduction in the minimum bill is a reasonable move which reduces potential discriminatory impact.

Q. WHAT IS THE BASIS FOR MR. ABBOTT'S VIEW THAT RESIDENTIAL DG CUSTOMERS ARE SUBSIDIZED?

A. His testimony suggests that the source of his criticism is the net metering provision applied to EPE DG customers' output.[39] State law requires net metering for residential DG in EPE's service area.[40] Renewable DG in other parts of the state is not net metered, but instead all output is sold back to the utility at avoided cost. In adopting renewable distributed generation rules, the PUC cited the comments of sponsoring legislators that Sec. 39.554 was "intended to encourage expansion of solar generation in El Paso County."[41] Further, the Commission found that it is in the public interest to allow distributed renewable generation throughout the state.[42] Mr. Abbott's disagreement with the net metering law is not a reasonable basis for opposing the Company's reduction in the residential DG minimum bill. To the extent that the law results in a subsidy, we must assume that the legislature found that the policy of expanding solar DG in El Paso was more important.

Q. ACCORDING TO MR. ABBOTT, THE COMPANY'S RELIANCE UPON AVERAGE RESIDENTIAL DISTRIBUTION DEMAND COST TO

[38] Indirectly, rooftop solar facilities are in competition with the electric utility's generation fleet.
[39] See, Direct Testimony of William Abbott direct at 5-6 and 8 (l. 18-22).
[40] Sec. Tex Util. Code §39.554 "PURA."
[41] *Rulemaking to Implement SB 365 & SB 981 Relating to Distributed Generation Project 39797* Order at 31-32, (5-24-2012).
[42] Project 39797 Order at 40.

EVALUATE THE MINIMUM BILL IS INCORRECT BECAUSE MOST DG CUSTOMERS HAVE A LOWER-THAN-AVERAGE LOAD FACTOR. DO YOU AGREE WITH THIS CRITICISM?

A. No. I do not support de-averaging residential costs in this manner. Many types of residential customer other than DG customers have low load factors, but rate regulation does not attempt to carve those customers out to pay higher rates based on their load factor. For instance, residences used as vacation homes or second homes generally will have a lower than average annual load factor. Residences with dual fuel HVAC systems may incur a lower than average load factor. Selectively choosing the load factors of DG customers for cost analysis has the potential to be discriminatory and anti-competitive.

Q. IS AN INCREASE IN THE DG MINIMUM BILL SUPPORTED BY INCREMENTAL COST ANALYSIS?

A. No. Economists generally favor an assessment of incremental costs when increased rates affect entry by competitors of the regulated utility[43]. The principal incremental cost to the utility is metering and interconnection, which is recovered by an up-front charge of $85 - $230 at the time of DG service initiation.[44] The Company states that no additional distribution costs upstream of the service line and meter have been identified as attributable to residential distributed generation.[45]

Q. WHAT IS YOUR CONCLUSION?

[43] Increasing the minimum bill potentially affects the viability of sizing solar facilities in excess of the residence's expected consumption, which can act as a barrier to entry.
[44] Docket 46831 Order, Attachment A at 51, (12-17-17).
[45] Docket No. 46831, Company Responses to CEP 8-2 and CEP 9-1.

A. Although elimination of the minimum bill would be appropriate, EPE's proposed reduction in the residential and SGS DG minimum bill should be adopted. Mr. Abbott's recommendation should be rejected.

Q. DOES THIS CONCLUDE YOUR TESTIMONY AT THIS TIME?

A. Yes.