BEFORE THE PUBLIC UTILITY COMMISSION OF TEXAS

IN THE MATTER OF THE APPLICATION OF	)	
EL PASO ELECTRIC COMPANY	)	CASE NO. 46831
TO CHANGE RATES	)	

CROSS-REBUTTAL TESTIMONY

OF

LAURIE A. TOMCZYK

ON BEHALF OF THE

U.S. DEPARTMENT OF DEFENSE AND ALL OTHER FEDERAL EXECUTIVE AGENCIES

JULY 21, 2017

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I. INTRODUCTION AND KEY RECOMMENDATIONS

Q. PLEASE STATE YOUR NAME, OCCUPATION, AND ADDRESS.

A. My name is Laurie A. Tomczyk. I am a Director and Owner at NewGen Strategies and Solutions, LLC, and I am located at 4528 Trails End, Lapeer, Michigan.

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

A. I am offering testimony on behalf of the U.S. Department of Defense and all other Federal Executive Agencies.

Q. ARE YOU THE SAME LAURIE A. TOMCZYK WHO PREVIOUSLY FILED TESTIMONY IN THIS PROCEDDING?

A. Yes.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. My cross-rebuttal testimony responds to the following issues and the associated direct testimonies of other intervenors in this case:

- Interruptible Rates
  - Mr. William Perea Marcus on behalf of the Office of Public Utility Counsel (OPUC)
  - Mr. Clarence L. Johnson on behalf of the City of El Paso (City)
  - Mr. Kevin C. Higgins on behalf of the Texas Industrial Energy Consumers (TIEC)
- Cost-of-Service Allocators - Mr. Clarence L. Johnson on behalf of the City of El Paso (City)

- Proposed Revenue Distribution - Mr. Clarence L. Johnson on behalf of the City of El Paso (City)
- Allocation of 69 kV Transmission Costs and Losses – Mr. Kevin C. Higgins on behalf of the Texas Industrial Energy Consumers (TIEC)

At this time, I am only addressing the issues and direct testimony identified above. The fact that I am not addressing other recommendations or claims made by parties in their direct testimony does not imply agreement with those recommendations or claims.

Q. WHAT ARE YOUR SPECIFIC RECOMMENDATIONS TO THE PUBLIC UTILITY COMMISSION OF TEXAS (COMMISSION) REGARDING INTERRUPTIBLE RATES?

A. I recommend the following:

- The Commission should reject Mr. Marcus' recommendations regarding interruptible rates because his recommendations do not adequately take into consideration the extensive value of interruptible loads to El Paso Electric Company's (EPE's) firm-load customers that extend beyond just avoided combustion turbine peaking plant costs.
- To the extent that the Commission is willing to consider Mr. Johnson's proposal that, "at a minimum, interruptible rates should recover full transmission costs in order to avoid subsidized delivery rates", the corresponding Rate 38 demand charge for interruptible loads served at transmission voltages should be $1.93 per kW-month.
- EPE's E2ENERGY allocators in their Cost-of-Service (COS) analyses should be revised such that it is based only on firm sales, rather than a combination of firm and interruptible sales, as supported by Mr. Higgins in his direct testimony.

Q. WHAT ARE YOUR RECOMMENDATIONS TO THE COMMISSION REGARDING CHANGES TO THE COS ALLOCATORS AND REVENUE DISTRIBUTION SUGGESTED BY THE CITY OF EL PASO WITNESS , CLARENCE JOHNSON?

A. I recommend the Commission reject Mr. Johnson's recommendations regarding COS allocators and revenue distribution between customer classes.

Q. WHAT IS YOUR RECOMMENDATION REGARDING ALLOCATIONSOF 69 KV TRANSMISSION LOSSES AND COSTS TO CUSTOMERS SERVED AT TRANSMISSION VOLTAGES?

A. Consistent with Mr. Higgin' opinion and the final Order issued by the Commission in Docket No. 46308, I recommend the Commission agree that no 69 kV transmission losses or costs should be assigned to customers served at transmission voltages.

II. INTERRUPTIBLE RATES

Q. WHAT RECOMMENDATIONS IN MR. MARCUS' TESTIMONY WOULD YOU LIKE TO ADDRESS REGARDING INTERRUPTIBLE RATES?

A. His recommendations are as follows:

- The interruptible discount should be in line with its value to customers over time.
- Interruptible rates should be increased in this case by 60% to move towards eliminating all subsidies to interruptible customers.
- In EPE's next rate case, the Commission should require EPE to take the following three specific actions:
  - Interruptible loads should be included as if they are firm in the next COS study for the purpose of allocating demand and energy costs.

- An explicit interruptible credit should be set based on taking another significant step to move toward the avoided cost of peaking capacity.
- The interruptible credit should not be removed from the revenue but should be treated as an expense that is functionalized to production demand and allocated on a demand-related basis to all customers except the interruptibles themselves.

Q. HOW WOULD YOU DESCRIBE EPE'S PROPOSED CLASS COS (CCOS) APPROACH FOR FIRM AND INTERRUPTIBLE LOADS ASSOCIATED WITH INTERRUPTIBLE CUSTOMERS?

A. EPE's CCOS primarily allocates costs across rate schedules based on firm loads of EPE customers. Rate Schedule 38 is not one of the rate schedules to which costs are allocated in the CCOS. Revenues from interruptible sales under Rate Schedule 38 are included as an operating revenue credit in the development of the net EPE revenue requirements for base rates in the CCOS. The operating revenue credit from interruptible sales under Rate Schedule 38 is allocated across firm customer classes using a Rate Base allocator. Using this methodology, the majority of the interruptible rate credit goes to the R01 Residential and R24 General Service rate schedules.

Q. MR. MARCUS SEEMS TO BELIEVE THAT THE HISTORICAL NUMBER OF INTERRUPTIONS SHOULD BE A KEY DETERMINING FACTOR IN THE DETERMINATION OF RATE 38 INTERRUPTIBLE RATES IN THIS RATE CASE. DO YOU AGREE?

A. No. I believe that EPE's proposed allowable interruptible criteria in this rate case for the future should be the main consideration. Mr. Marcus did not provide any evidence that the amount of historical interruptions is a good indicator of future interruptions, nor did he try to analyze the impact to historical interruptions resulting from EPE's proposed changes to the Rate 38 Schedule regarding specifics on allowable number of hours of interruptions per year and number of interrupts per week. Credit should be given to interruptible customers based on the interruptible criteria agreed to by those customers, not actual historical interruptions. Historical interruptions are not necessarily a good indicator of future interruptions.

Q. WHAT CAPACITY DOES MR. MARCUS BELIEVE CAN BE AVOIDED DUE TO INTERRUPTIBLE LOADS?

A. Interestingly, Mr. Marcus' Question on Page 8, Lines 8 and 9, of his direct redacted testimony asks that specifically, but the associated Answer he provides on Page 8, Lines 10 through 19, and Page 9, Lines 1 through 8, only quantifies avoided energy. Therefore, I do not know the answer to that question. EPE's potential avoided costs of capacity due to interruptible loads is of much more significance than its potential avoided costs of energy due to interruptible loads. EPE's estimate of the avoided amount of capacity is equal to 52 MW as shown in EPE's response to FMI RFI No. 1-14.

Q. DOES MR. MARCUS BELIEVE THAT INTERRUPTIBLE LOADS HAVE ANY VALUE TO EPE OR ITS CUSTOMERS REGARDING TRANSMISSION CONSTRAINTS?

A. I did not see anything in Mr. Marcus' direct testimony that acknowledges any value associated with transmission. In fact, his only statement regarding the relationship between interruptible loads and transmission is shown on Page 9, Lines 5 through 8, as follows:

"Consider the following example. If an interruption is called on a peak day because a large generator trips off line, the transmission would still need to be available to

serve the interruptible customer's full load on that same hot day in the event that the generator had not tripped."

Q. WHAT DO THOSE STATEMENTS SEEM TO IMPLY?

A. Those statements seem to imply that an interruption can only be called by EPE for generation constraints when, in fact, an interruption can also be called based on transmission constraints, as well as a myriad of other emergency conditions.

Q. WHAT VALUE DOES MR. MARCUS RECOMMEND BE ASSIGNED TO INTERRUPTIBLE LOADS?

A. Mr. Marcus recommends this value be based on avoided combustion turbine peaking plant costs. He implies in his testimony on Page 13, Lines 3 and 4, that EPE witness Carrasco agrees, but in fact Mr. Carrasco indicates that interruptible loads allow service to be maintained to firm loads during periods of both generation or transmission capacity constraints.[1]

Q. DO YOU BELIEVE THE VALUE OF INTERRUPTIBLE LOADS IS LIMITED TO EPE'S AVOIDED COMBUSTION TURBINE PEAKING PLANT COSTS?

A. No. The allowable "emergency conditions" for interruption in EPE's current and proposed Texas Rate Schedule 38 are as follows and allow for interruptions far beyond just the ability to avoid the use of a combustion turbine peaking plant:

"Emergency conditions are deemed to exist at any time, in the sole judgment of the Company, that demands for electricity exceed or are expected to be likely to exceed the Company's available electric supply for whatever reason or reasons including, but not limited to, breakdown of generating units, distribution equipment or other critical facilities; short-term or long-term shortages of fuel or generation, distribution, and other facilities; or requirements or orders of governmental agencies. The Company may not interrupt the Customer (1) due solely to differences in the Company's marginal cost of energy and the energy-related charges for Noticed

[1] See Carrasco Direct Testimony at Pages 52-53.

Interruptible Power Service, or (2) to continue or make non-firm off-system sales." Consideration should be given to the value of avoidance of environmental emissions and costs associated with the avoided operation of a combustion turbine peaking plant. Also, the ability to interrupt based on a wide range of conditions as identified above is valuable to EPE's customers in that outages for those customers can be avoided for a significant number of emergency conditions. Finally, interruptible rates can be used as an economic incentive to retain large loads.

Q. ACCORDING TO MR. MARCUS, WHAT IS THE MAGNITUDE OF THE DISCOUNT THAT EPE'S INTERRUPTIBLE CUSTOMERS RECEIVE FROM FIRM RATES?

A. Mr. Marcus believes the magnitude of the discount is $13,210,018.

Q. HOW DID MR. MARCUS DETERMINE THIS FIGURE?

A. Mr. Marcus explains how he derived this number in his direct testimony on Page 10, Lines 7 through 14. Simply, he relied on the information provided in EPE's responses to OPUC RFI Nos. 1-3 and 1-4. EPE's response to OPUC RFI No. 1-3 provided information as to the revenues that would have been received from current interruptible customers based on firm and interruptible rates resulting from the order in Docket No. 44941. EPE's response to OPUC RFI No. 1-4 provided information as to the revenues that that would have been received from interruptible customers had both their firm and interruptible loads been charged based on firm rates resulting from the order in Docket 4491. The difference is equal to $13,210,018.

Q. DO YOU BELIEVE THIS IS AN ACCURATE PORTRAYAL OF THE INTERRUPTIBLE DISCOUNT?

A. No. For purposes of his testimony in this case, I do believe Mr. Marcus should have relied on EPE's responses to OPUC RFI Nos. 1-3 and 1-4 that were based on rates resulting from the previous Docket No. 44941. At the very least, the discount should have been calculated based on EPE's proposed firm and interruptible rates in this rate case. Also, it is important to note that if all EPE's interruptible customers were billed entirely under a firm rate, EPE's firm rates that resulted from the previous Docket No. 44941 and EPE's proposed firm rates in this docket would be different than those assumed by EPE in response to OPUC RFI No. 1-4. This is confirmed by EPE in their response to OPUC RFI No. 1-4.

Q. HAS EPE PROVIDED AN ESTIMATE OF FIRM RATES THEY WOULD HAVE PROPOSED FOR CUSTOMERS WITH INTERRUPTIBLE LOADS HAD BOTH THE FIRM AND INTERRUPTIBLE LOADS OF THOSE CUSTOMERS BEEN BILLED AT FIRM RATES?

A. No. This information was requested in Vinton RFI No. 4-1, but EPE indicated in their response that they had not made any calculations as to how the design of the firm rates would be different if all interruptible loads were billed under the firm rates.

Q. DID MR. MARCUS PROVIDE FOR COMPARISON ANY DISCOUNTS OFFERED BY OTHER TEXAS UTILITIES OUTSIDE OF ERCOT FOR INTERRUPTIBLE LOADS?

A. Yes. He stated that the maximum interruptible credit that Southwestern Public Service (SPS) gives for a transmission voltage customer is $6.58 per kW-month in the summer and $4.64 per kW-month in the winter for customers taking the "No Notice Option".

Q. DO YOU CONSIDER THIS TO BE AN "APPLES-TO-APPLES" COMPARISON WITH EPE'S PROPOSED INTERRUPTIBLE DISCOUNT?

A. No. The treatment of interruptible loads in the SPS tariff differs significantly from the treatment in the EPE proposed tariff. I am only going to address the following, which are just a few examples of the numerous differences:

- Demand rates charged to large power customers served at transmission voltages, regardless of whether a portion of their load is interruptible
- Annual number of allowable hours of interruptions
- "Carrot versus stick" approach to interruptible loads
- Determination of firm and interruptible billing demands for customers with interruptible load and associated incentives

Q. PLEASE PROVIDE A COMPARISON OF THE SPS CURRENT AND EPE PROPOSED DEMAND RATES FOR LARGE POWER CUSTOMERS SERVED AT TRANSMISSION VOLTAGES?

A. The following tables provides this comparison for large power customers served at transmission voltages of 115 kV or above.

Table LAT-1: SPS and Proposed EPE Demand Rates for Large Power Customers Served at Transmission Voltages

	Summer $/kW-Mo.	Winter $/kW-Mo.
SPS Current Large General Service-Transmission (Sheet No. IV-108)	$11.16	$7.81
EPE Proposed Large Power Service Rate - Transmission Voltage (Schedule No. 25) (Errata Filing)	$18.97	$14.84

I believe this information is important because the discount offered for interruptible loads should be at least somewhat commensurate with the level of demand charges associated with firm loads, particularly if the demand charges are not strictly cost-of-service based.

Q. WHAT ARE THE DIFFERENCES IN NUMBER OF INTERRUPTIBLE HOURS BETWEEN THE CURRENT SPS AND PROPOSED EPE TARIFFS?

A. The SPS tariff allows customers to choose the maximum number of annual hours of interruption (i.e., 40, 80, or 160 hours), whereas the EPE proposed tariff sets the maximum number of hours at 200 per year.

Q. WHAT DO YOU MEAN BY THE "CARROT VERSUS STICK" APPROACH?

A. SPS charges the same Large General Service-Transmission rates for both firm and interruptible loads, and then offers a demand credit for interruptible loads. EPE proposes to charge different rates for firm versus interruptible loads, with rates for interruptible loads being discounted from rates for firm loads.

Q. WHAT ARE THE DIFFERENCES IN HOW INTERRUPTIBLE LOADS ARE DETERMINED IN THE SPS AND PROPOSED EPE TARIFFS?

A. The SPS tariff Sheet No. IV-177 specifies the "**lesser** of the Customer's Contract Interruptible Load (CIL), or the actual Interruptible Demand, during the billing month" where:

- CIL is the median of the Customer's maximum daily thirty (30) minute integrated kW demands occurring between the hours of 12:00 noon and 8:00 p.m. Monday through Friday, excluding federal holidays, during the period June 1 through September 30 of the prior year, less the Contract Firm Demand, if any.

- Interruptible Demand is the Customer's maximum thirty (30) minute integrated kW demand that is used during the month, less the Contract Firm Demand, if any but not less than zero. Interruptible Demand is measured between the hours of 12:00 noon and 8:00 p.m. Monday through Friday, excluding federal holidays.

The EPE tariff defines the "Noticed Interruptible Power Billing Demand" as being equal to Total Billing Demand minus Firm Power Billing Demand where:

- Total Billing Demand is the maximum demand consisting of both firm and interruptible demand, and is defined as the highest thirty (30) minute average kW load determined by measurement.
- Firm Power Billing Demand is the lesser of (1) the Total Billing Demand or (2) the Contract Firm Power Demand established in the Contract for Power Service, but not less than the Minimum Firm Contract Capacity specified in the Contract for Power Service.

Both the SPS and EPE proposed tariff schedules that apply to customers with interruptible loads provide incentives to minimize total billed demand, including demand associated with both firm and interruptible loads. However, the difference lies in the determination of the interruptible demand if the customer's total demand exceeds the firm contract demand. The EPE proposed tariff provides an incentive to minimize the amount of interruptible demand in excess of the firm demand, regardless of whether the interruptible load occurred in EPE's on-peak or off-peak periods, in order to minimize the charges under the proposed Rate Schedule 38. The SPS tariff provides an incentive to shift interruptible demand usage in excess of the firm contract demand to SPS on-peak hours in order to maximize the interruptible credit. Such incentive is not offered under the EPE proposed tariff schedules.

Q. DO YOU AGREE WITH MR. MARCUS' RECOMMENDATIONS REGARDING THE TREATMENT OF INTERRUPTIBLE LOADS IN THE COS STUDY USED IN EPE'S NEXT RATE CASE (SEE PAGE 15, LINES 4 THROUGH 14 OF HIS TESTIMONY)?

A. His recommendations are so general, that I am not clear on exactly what he is recommending. He recommends interruptible loads be included as if they are firm in the next cost of service study for the purpose of allocating demand and energy costs, but he does not go on to explain the specifics of how those interruptible loads would be incorporated into the determination of the demand and energy allocators for the cost of service study. Further, he does not propose any specifics as to how costs would be allocated to those interruptible loads, such as costs associated with combustion turbine peaking plant costs or transmission costs, or how the interruptible credit would be calculated. For example, he recommends that the interruptible credit be removed from revenue and treated as an expense that is functionalized to production demand and allocated on a demand-related basis to all customers except the interruptibles themselves. What is the type of demand allocator he is recommending for the "interruptible credit expense" and how would it be calculated?

Q. WHAT RECOMMENDATIONS IN MR. JOHNSON'S TESTIMONY WOULD YOU LIKE TO ADDRESS REGARDING INTERRUPTIBLE RATES?

A. Mr. Johnson's recommendation is that the interruptible credit be revised in a manner that produces $2.5 million of additional base revenue by changing the interruptible credit rate moderation adjustment in EPE's calculations from 189% to 158%. He indicates this change will result in a $4.60 interruptible demand charge for interruptible customers served at transmission voltages, which recovers close to full transmission costs for those interruptible loads based on EPE's unit cost of service analysis in Schedule P-6.2.

Q. WERE YOU ABLE TO REPLICATE THE NUMBERS MR. JOHNSON QUOTED IN HIS RECOMMENDATIONS USING EPE'S ERRATA RATE DESIGN EXCEL FILE TITLED, "ATTACHMENT 08_WP Q-07(A) TX RATE DESIGN - 2017 GRC (ERRATA)"?

A. Yes, I changed the Rate Moderation Adjustment on Line 2 in the "Rate 38 Int Credit" sheet to 58.348% and it resulted in a Transmission Voltage Rate 38 demand charge of $4.60 per kW on the "Rate 38" sheet in Line 28 and a Primary Voltage Rate 38 demand charge of $7.75 per kW in Line 24 of the "Rate 38" sheet. In doing so, the calculated total base revenues in Line 31 on the "Rate 38" sheet changed to $6.4 million and the difference from target revenue in Line 32 on the "Rate 38" sheet changed to $2.5 million.

Q. WHAT IS THE BASIC PREMISE OF MR. JOHNSON'S RECOMMENDATIONS AS TO THE INTERRUPTIBLE DEMAND CHARGES THAT THE COMMISSION SHOULD ADOPT FOR THIS RATE CASE?

A. As stated on Page 50, Lines 1 and 2, Mr. Johnson states that, "at a minimum interruptible rates should recover full transmission costs in order to avoid subsidized delivery rates."

Q. WHAT EPE PROPOSED FIRM RATE SCHEDULES, AND CORRESPONDING SERVICE VOLTAGES, ARE ASSOCIATED WITH EPE CUSTOMERS HAVING INTERUPPTIBLE LOAD?

A. In total, EPE has nine customers with interruptible loads, four of which are served on their own firm rate schedules at transmission voltages. The other five are served under Rate 25

Large Power Service at either transmission or primary distribution voltages, but they are not the only customers served on this rate schedule.2 By far, the majority of available interruptible load is from customers served at transmission voltages. Additional information on interruptible customers is as follows:

- The only customer billed under EPE Rate 15 has both firm and interruptible loads, and that customer is served at transmission voltage
- Five customers that are billed under EPE Rate 25 have both firm and interruptible loads, and those customers are served at either transmission or primary voltages; there are additional Rate 25 customers that do not have interruptible loads
- The only customer billed under EPE Rate 26 has both firm and interruptible loads, and that customer is served at transmission voltage
- The only customer billed under Rate 30 has both firm and interruptible loads, and that customer is served at transmission voltage
- The only customer billed under Rate 31 has both firm and interruptible loads, and that customer is served at transmission voltage

Q. HOW DID MR. JOHNSON DEVELOP HIS PROPOSED INTERRUPTIBLE DEMAND CHARGE OF "APPROXIMATELY $5.00 PER KW-MONTH" FOR INTERRUPTIBLE LOADS SERVED AT TRANSMISSION VOLTAGES?

A. Mr. Johnson recommends that the interruptible demand rates in this rate case recover close to full transmission costs for interruptible customers[3]. He goes on to specify that the interruptible demand charge should be set at "approximately $5.00 per kW-month" for

[2] 90% of EPE's interruptible load is from customers served at transmission voltages under Rates 15, 25, 26, 30, and 31, per EPE's response to OPUC RFI 1.3, in the Excel File titled, "OPUC 01-03_Attacment 01" on the "Interruptible (OPCU1-3) sheet". See information in Excel Columns H and K. The other 10% of EPE's interruptible load is from customers served at primary voltages under Rate 25.
[3] See Johnson Direct Testimony on Page 50, Lines 1 and 2 and Lines 11 and 12.

service at transmission voltage, which recovers close to full transmission costs, and that the associated reduced credit be allocated as a cost offset to all firm classes. As a basis for his recommendations, he refers to EPE's Schedule P-6.2 Unit Cost Analysis that shows functionalized cost-of-service demand rates ($/kW-month) by rate class. The unit demand rate information provided for Rate 25 is shown in the following table, as well as the associated approach Mr. Johnson uses to calculate his recommended interruptible demand rate of $5.00 per kW-month[4] for interruptible loads served at transmission voltages.

[4] See Johnson Direct Testimony on Page 50, Line 4.

Table LAT-2: EPE Unit Demand Cost Results for Rate 25 Large Power Service and Derivation of Mr. Johnson's Proposed Interruptible Demand Charge

Line		
1	**DEMAND ($/kW) (1)**	
2	Demand Production	$15.909
3	Demand Transmission	1.856
4	Demand Distribution - LD	1.126
5	Demand Distribution - PTF Prim	0.457
6	Demand Distribution - PTF Sec	0.204
7	Demand Distribution - OH Prim	0.408
8	Demand Distribution - OH Sec	0.040
9	Demand Distribution - UG Prim	0.877
10	Demand Distribution - UG Sec	0.194
11	Demand Distribution - Tran Prim	0.499
12	Demand Distribution - Tran Sec	0.256
13	Total	$21.827
14	Demand Prod % (Line 2 / Line 13)	73%
15	Demand Delivery % (1 – Line 14)	27%
16	Approx Interruptible Demand Chg	
17	=$18.45/kW-mo. X Line 15 (2)	$5.00

(1) Source: EPE Schedule P-6.2
(2) For interruptible customers served at transmission voltage. $18.45/kW-mo. represents Rate 25 Firm Demand Component for service at transmission voltage. Source: Attachment 08_WP Q-07(a) TX Rate Design - 2017 GRC (ERRATA).

Q. DO YOU HAVE ANY ISSUES WITH REGARD TO HOW MR. JOHNSON DETERMINED THE FULL TRANSMISSION COSTS FOR CUSTOMERS SERVED AT TRANSMISSION VOLTAGES?

A. Yes. While, Mr. Johnson recommends that the interruptible demand rates in this rate case recover close to full transmission costs for interruptible customers, his recommended interruptible demand rate for customers served at transmission voltages of approximately

$5.00 per kW-month significantly exceeds the unit costs for demand-related transmission in EPE's Schedule P-6.2 on Pages 3 and 4 at Line 18 for rate classes with interruptible loads. These unit costs for demand-related transmission in EPE's Schedule P-6.2 range from $1.38 to $2.05 per kW-month for classes with interruptible loads. I believe this discrepancy mainly results from how Mr. Johnson calculated the percentages shown in Table LAT-2 on Lines 14 and 15. I do not understand why he included demand-related distribution costs on Lines 4 through 12 in the calculation of the percentage on Line 14 for purposes of determining transmission costs for interruptible customers served at transmission voltages. For the percentage shown on Line14, I would take Line 2 and divide it by Lines 2 plus 3. The result is 90%. Thus, the percentage on Line 15 would be 10% and the resulting interruptible demand charge on Line17 would be $1.93 per kW-month. This falls within the range of unit costs for demand-related transmission in EPE's Schedule P-6.2 for classes with interruptible loads and is also exactly equal to EPE's proposed interruptible demand rate for interruptible load served at transmission voltages as shown in EPE's Excel file titled "Attachment 08_WP Q-07(a) TX Rate Design - 2017 GRC (ERRATA)". Please see the sheet with the proposed rate design for Rate 38 titled "Rate 38" on Line 28.

Q. WHAT ARE MR. HIGGINS/ OBSERVATIONS AND RECOMMENDATIONS REGARDING THE TREATMENT OF INTERRUPTIBLE LOAD IN EPE'S COST OF SERVICE ANALYSES?

A. Mr. Higgins acknowledges that generally interruptible loads are not included in the determination of the COS allocators used by EPE. However, EPE's determination of the E2ENERGY allocator includes interruptible energy. This has the effect of allocating increased costs to firm rate schedules with interruptible load. Mr. Higgins recommends that interruptible load and revenues not be included in the determination of any class COS allocators.

Q. DO YOU AGREE WITH MR. HIGGINS ON THIS ISSUE?

A. Yes. EPE's Rate 38 schedule clearly indicates that, "Interruptible sales under this rate schedule are non-firm sales and as such are not subject to cost-of-service allocations in any Company rate case." I believe the intention of EPE was to conform with this provision, but they fell short in their determination of their E2ENERGY allocator.

Q. WHAT DO YOU RECOMMEND REGARDING THIS ISSUE IDENTIFIED BY MR. HIGGINS?

A. Keeping with the provision in EPE's Rate 38 schedule that non-firm sales should not be subject to COS allocations in any Company rate case, I recommend that all of EPE's appropriate COS allocators be derived based on firm load and associated revenues. It is inconsistent that one of EPE's allocators also takes into account interruptible load.

III. COST-OF-SERVICE ALLOCATORS

Q. WHAT DOES MR. JOHNSON RECOMMEND REGARDING THE CALCULATION OF THE EPE SYSTEM LOAD FACTOR INHERENT IN THE DETERMINATION OF THE 4 CP A&E ALLOCATOR? HOW DOES THIS COMPARE TO EPE'S RECOMMENDATION?

A. Mr. Johnson recommends the use of an average 4 CP system demand in the denominator of the load factor equation[5], while EPE Witness George Novela recommends the use of a 1 CP

[5] See Johnson Direct Testimony on Page 15, Lines 20 and 21.

system demand in the denominator of the load factor equation. Mr. Novela offers as support the Commission's final order in the SPS Docket No. 43695.[6] He states that in that case, the Commission found that the use of a 1 CP factor was more consistent with how SPS planned and built its generation and transmission systems.

Q. DOES MR. JOHNSON CONSIDER THE COMMISSION'S FINAL ORDER IN THE SPS DOCKET NO. 43695 TO BE RELEVANT TO THIS CASE REGARDING THE LOAD FACTOR CALCULATION?

A. No. He believes the Commission's decision in Docket No. 43695 was based on facts specific to the SPS case. In support of this argument, he states that in the final order , "the Commission refers to the Southwestern Power Pool (SPP) capacity margin requirement applicable to SPS, and relies upon the opinion of SPS's cost allocation witness."[7]

Q. WHAT DO YOU THINK OF MR. JOHNSON'S OPINION REGARDING THE RELEVANCE OF THE FINAL ORDER IN DOCKET NO. 43695 PERTAINING TO THE CALCULATION OF THE SYSTEM LOAD FACTOR?

A. I think Mr. Johnson's testimony is misleading. He implies that the SPP capacity margin requirement applicable to SPS was a key determining factor in the Commission's decision in that docket regarding the load factor calculation, thus the Commission's decision "appears to be based on facts specific to the SPS case"[8] and, therefore, is not relevant to this case. I do not agree. The following is a complete set of specific findings of fact (FOF) in that order pertaining to this issue, and it shows that the SPP capacity margin requirement was only one piece of information considered by the Commission in its decision:

[6] See Novela Direct Testimony on Page 28, Lines 4 through 10 and 18 through 22.
[7] See Johnson Direct Testimony on Page 17, Lines 3 through 6.
[8] See Johnson Direct Testimony on Page 17, Lines 3 through 6.

- **FOF 246A.** The only aspect of SPS's average-excess-demand coincident-peak calculation that was contested in this proceeding was SPS's calculation of the system load factor by averaging the monthly peak for the four months of June through September, adjusted for loss (4CP).
- **FOF 247A.** Commission Staff, TIEC, Occidental, and State Agencies argued SPS should have instead based its system load factor on the single highest system peak, adjusted for loss (1CP).
- **FOF 248A.** Commission Staff stated that use of 1 CP to calculate the system load factor best reflects cost causation because SPS uses the single system peak for resource planning.
- **FOF 249A.** TIEC cited to the Southwest Power Pool's requirement that its members have capacity margins based on 1 CP.
- **FOF 250A.** SPS's witness, Mr. Luth, conceded that use of a 1CP system load factor is reasonable.
- **FOF 251A.** SPS's system load factor used for allocating demand should be based on 1CP.

Q. WHAT DO YOU THINK IS OF MOST IMPORTANCE IN THAT ORDER TO THIS RATE CASE?

A. The order acknowledges that the use of 1 CP to calculate the system load factor best reflects SPS's cost causation because SPS uses the single system peak for resource planning. In this rate case, EPE Witness Novela represents that EPE also uses the same type of approach for resource planning and, thus, the final order in Docket No. 43695 is relevant to this case.

Q. WHAT IS YOUR OPINION OF THE IMPORTANCE OF MR. JOHNSON'S TESTIMONY REGARDING THE WESTERN ELECTRICITY COORDINATING COUNCIL (WECC) SYSTEM RELIABILITY ANALYSIS?

A. I consider it to have approximately the same amount of importance as the information on the SPP required capacity margins in Docket No. 43865. While it is one piece of information to consider, the focus should really be on how the utility does its own resource planning.

Q. GENERALLY, WHAT DOES MR. JOHNSON RECOMMEND WITH REGARD TO THE CLASSIFICATION OF GENERATION NON-FUEL OPERATIONS AND MAINTENANCE (O&M) EXPENSES?

A. Mr. Johnson recommends that the classification of these expenses reflect the guidance in the NARUC Manual[9][10]. The subsequent specifics of his recommendations indicate that he is referring to the guidance in the NARUC Manual on pages 36 through 38 regarding NARUC's "Cost Accounting Approach". This information provides recommendations by FERC account as to how production costs should be classified as being demand-related and/or energy related. The result of his recommendations is to classify more costs as being energy-related versus demand-related.

Q. WHAT ARE YOUR OVERALL OBSERVATIONS REGARDING HIS RECOMMENDATIONS FOR CLASSIFYING GENERATION O&M EXPENSES?

A. His recommendations are not completely consistent with the guidance offered in the NARUC Manual on pages 36 through 38. Also, some suggested interpretations of the

[9] See Johnson Direct Testimony on Page 22, Lines 5 and 6.
[10] National Association of Regulatory Utility Commissioners *Electric Utility Cost Allocation Manual* (January 1992)

NARUC Manual[11] imply that all production costs should be classified as demand-related if the Average & Excess Method is used to allocate demand-related costs to customer classes since Average & Excess allocators include a weighting for energy usage. Ultimately, I recommend that the Commission assume EPE has made a careful consideration of costs in each production account as to appropriate energy/demand weightings. Aside from certain general guidance referenced in the NARUC manual, Mr. Johnson did not offer any compelling reasons to deviate from EPE's proposed production classification methodology.

Q. WHAT ARE SPECIFIC EXAMPLES OF WHERE MR. JOHNSON'S RECOMMENDATIONS DIFFER FROM THE GUIDANCE OFFERED IN THE NARUC MANUAL?

A. EPE classifies non-labor expenses in Account 506 as energy-related. NARUC Manual guidance suggests these expenses should be classified as demand-related. However, Mr. Johnson did not recommend any changes to EPE's classification of costs in this account. Also, he classified 35% of costs in Accounts 517, 519, 520, and 523 as energy-related based on Palo Verde Operations overall payroll as a percentage of total Palo Verde Operations non-fuel expense. The NARUC Manual recommends that classifications of Accounts 519, 520, and 523 be analyzed independent of each other, and that labor-related costs associated with each account be classified as demand related and non-labor costs be classified as energy related. The NARUC manual further recommends that costs in Account 517 be classified on the basis of the relative proportions of labor cost contained in the other accounts in the accounting group.

[11] See Page 39 of the NARUC Manual.

IV. REVENUE DISTRIBUTION

Q. WHAT ARE MR. JOHNSON'S SPECIFIC RECOMMENDATIONS REGARDING REVENUE DISTRIBUTION TO CLASSES IN THIS CASE?

A. Mr. Johnson recommends two rate moderation tools: (1) no class receives a base revenue reduction as long as the total firm base revenues increase and (2) the remaining classes receive a base revenue increase midway between the current structure of relative revenues receive a base revenue increase midway between the current structure of relative revenues and the class base revenue resulting from equalized rates of return. His recommended revenue distribution is shown in Schedule CJ-4.

Q. WHAT ARE YOUR RECOMMENDATIONS FOR REVENUE DISTRIBUTION TO MILITARY RATE 31?

A. I support the revenue distribution to Military Rate 31 as proposed by EPE. At a minimum, I find Mr. Johnson's proposed revenue distribution in Schedule CJ-4 to be inconsistent with his recommended "rate moderation tools" without me even offering an opinion as to the appropriateness of those proposed "rate moderation tools".

Q. PLEASE EXPLAIN WHERE YOU SEE THIS INCONSISTENCY?

A. In Schedule CJ-4, the column titled "Base Percentage at Cost" represents the percentage base rate changes proposed by EPE that are mainly COS-based while the percentage base rate changes recommended by Mr. Johnson are shown in the column titled "Base Rev Percentage". Of importance to note is that for all rate schedules where a base percentage rate decrease is shown in the column titled "Base Percentage at Cost", except for Military Rate 31, Mr. Johnson recommends a zero percent increase to base rates as shown in the column titled "Base Rev Percentage". For the Military Rate 31, however, he recommends a 2.3 percent increase. I do not see any information that Mr. Johnson provided which supports this notably different treatment of Military Rate 31.

V. ALLOCATION OF 69 KV TRANSMISSION COSTS AND LOSSES TO EPE CUSTOMERS SERVED AT 115 KV TRANSMISSSION VOLTAGES

Q. DO YOU SUPPORT THE RECOMMENDATIONS MADE BY TIEC WITNESS KEVIN C. HIGGINS IN HIS DIRECT TESTIMONY THAT SUGGEST 69 KV TRANSMISSION LOSSES AND COSTS SHOULD NOT BE ALLOCATED TO CUSTOMER SERVED AT 115 KV TRANSMISSION VOLTAGES[12]?

A. Yes. I believe his recommendations are consistent with my recommendations in my direct testimony for this case.

Q. IS THERE ANYTHING YOU WOULD LIKE TO ADD REGARDING THIS ISSUE?

A. Yes. I would like to add that at the time direct testimony from intervenors in this case was due, a draft order had been issued by the Commission in Docket No. 46308, but not a final order. Subsequently, a final order was issued by the Commission in this case and it supports the fact that transmission losses incurred on EPE's system differ between customers served at 115 kV versus 69 kV transmission voltages, thus costs associated with EPE's 69 kV system should not be allocated to customers served at 115 kV transmission voltages.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

[12] See Higgins Direct Testimony on Pages 19 through 20 and Page 38 through 39.