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

REBUTTAL TESTIMONY

OF

MANUEL CARRASCO

FOR

EL PASO ELECTRIC COMPANY

NOVEMBER 19, 2021

TABLE OF CONTENTS

EXHIBITS

I. Introduction and Qualifications

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

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

Q. HOW ARE YOU EMPLOYED?

A. I am employed by El Paso Electric Company ("EPE" or the "Company") as the Manager of Rate Research.

Q. ARE YOU THE SAME MR. MANUEL CARRASCO WHO SUBMITTED DIRECT TESTIMONY?

A. Yes, I am.

II. Purpose of Rebuttal Testimony

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. The purpose of my rebuttal testimony is to respond to the intervening parties and Commission Staff filed testimony regarding certain revenue adjustments, revenue distribution, and rate design.

Q. DO THE PARTIES AGREE ON HOW GRADUALISM SHOULD BE APPLIED IN THIS CASE?

A. No, they do not. As noted above, some parties agreed that because of the pandemic, it was proper to make some moderation adjustment. Other parties disagreed and suggested that it was not necessary to make the moderation adjustment proposed by EPE and that each class should pay its full cost of service. Because of the pandemic, the 2020 test year was different as compared to prior test years so EPE found it necessary to moderate the rate increase for certain rate classes. In Exhibit MC-2R, I listed the revenue increase distribution by rate class suggested by the intervening parties and Commission Staff, if any, using EPE's requested base-rate increase. Some distributions were specified in the testimonies, others required me to decipher what the intended distributions were.

Q. WHAT DO YOU CONCLUDE REGARDING THESE CONFLICTING APPROACHES?

A. It is entirely reasonable that intervenors will favor approaches that benefit their constituencies. Ideally, all rate classes would move towards full cost, but EPE acknowledges that several classes actually move further from cost because it is necessary to moderate the impact of the requested revenue increase on certain rate classes.

III. Recommendations by CEP Witness Johnson

Q. CEP WITNESS JOHNSON RECOMMENDS THAT EPE'S PROPOSED $1.2 MILLION REDUCTION TO TEST YEAR REVENUE RELATED TO THE RATE 38 NON-COMPLIANCE PENALTY BE DENIED. HOW DO YOU RESPOND?

A. Penalties for interruptible non-compliance, especially at the magnitude recorded in the test year, are truly non-recurring. EPE's response to CEP 9-38 shows that in 2019, the Company did not record such penalties and in EPE's response to VS 5-3, which states that there have been no curtailments under the interruptible service tariff in 2021, thus no occasion to penalize for non-curtailments, demonstrate that such penalties are nonrecurring.

To further demonstrate that the penalty during the test year is non-recurring, Exhibit MC-1R compares the non-curtailment penalties from 2016 through 2021. The test year penalty is between five to six times the amount of the penalties, of the other years, if any. Furthermore, Mr. Johnson's comparison of EPE's proposed decrease of $1.21 million in penalties to total rebilled revenue, in his schedule CJ-1, is misleading as it is not a compatible comparison and should therefore be disregarded.

Q. MR. JOHNSON RECOMMENDS THAT EPE'S ANNUALIZATION ADJUSTMENT FOR THE IMPACT OF ENERGY EFFICIENCY PROGRAMS BE REJECTED. IS THIS RECOMMENDATION ACCEPTABLE?

A. To clarify, the amount EPE is proposing to reduce Texas base revenues is $1.1 million, not $1.3 million as inaccurately referred on page 11 of Mr. Johnson's testimony.[1] In response to this question, the response is no. Without this annualization adjustment, rates cannot reasonably be expected to recover the Company's revenue requirement authorized by the

[1] See Schedule O-4.1, page 7 of 12, line 21, Non-Fuel Revenue.

Commission. Without the adjustment, a greater level of billing determinants will be used to set the rates, although it is known that customers have taken energy conservation measures through EPE energy efficiency programs throughout the test year that reduced year-end billing determinants. The resulting rates will not be set such that the revenues will recover the cost of service established in this proceeding. That will counter what the Commission has long adhered and known as the "matching principle."

Q. MR. JOHNSON CLAIMS THAT EPE'S ENERGY EFFICIENCY ANNUALIZATION ADJUSTMENT IS NOT "KNOWN" AND IS NOT "MEASURABLE." HOW DO YOU RESPOND?

A. Mr. Johnson argues that energy efficiency savings are not "known and measurable." He fails to acknowledge that EPE's energy efficiency programs have historically been verified to actually achieve energy efficiency savings and, therefore, those programs are known to have happened and are measurable because the savings must meet Commission-approved criteria to be regarded as savings.

The evaluation, measurement, and verification ("EM&V") process, pursuant to 16 Texas Administrative Code ("TAC") § 25.181 ("Energy Efficiency Rule") provides, with reasonable certainty, the measurement and verification of energy and demand savings of energy efficiency programs. Those savings are documented using methods that can involve measurements, engineering calculations, statistical analyses, and/or computer simulation modeling. Mr. Johnson, however, recommends an unquantifiable and arbitrary level of accuracy for these savings to be considered a "known and measurable" adjustment to the test year. His arbitrary conclusion that the effect of the energy efficiency programs is not known and measurable clearly conflicts with the Commission's stated purpose for the EM&V process, which is that "[t]he goal of this framework is to ensure that the programs are evaluated, measured, and verified using a consistent process that allows for accurate estimation of energy and demand impacts." Mr. Johnson provides no evidence that the EM&V program has not achieved that goal. Given the effort that the PUCT-appointed EM&V contractor goes through to provide the PUCT assurances about the energy and demand savings achieved through the energy efficiency programs it

approves, it is troubling to think those efforts are not sufficient to meet the burden of proof for a known and measurable adjustment as envisioned by Mr. Johnson.[2]

Q. DID THE COMMISSION VERIFY THE VALUES YOU USED FOR MAKING YOUR ADJUSTMENT?

A. To clarify, the Texas energy efficiency annualization adjustment originally filed by EPE was based on achieved and unverified annual kilowatt-hour ("kWh") savings of 30,669,898 in 2020. No budgeted savings, as Mr. Johnson inaccurately states in his testimony, were used in the adjustment calculation.

In response to the question, yes, the Commission verified the values used in making the energy efficiency annualization adjustment. On April 1, 2021, EPE filed its 2021 Energy Efficiency Plan and Report ("EEPR") with the Commission which details its achievements for 2020.[3] The achievements for 2020 in the EEPR amounted to 30,704,424 kWh in verified savings from EPE's energy efficiency programs. Those verified savings are 34,526 kWh more than what was originally used in calculating the energy efficiency annualization adjustment. The fact that the projects and associated energy savings for EPE's 2020 energy efficiency programs were verified and approved by the PUCT's EM&V contractor demonstrates that the Commission vetted these energy savings.

Q. DOES TEST YEAR DATA ALREADY INCLUDE THE FULL IMPACT OF THE ENERGY EFFICIENCY PROGRAMS?

A. No. Unadjusted test year data includes the energy savings associated with energy efficiency programs only beginning with the month that the program participants completed the energy efficiency measures. Participation and completion of these measures occurred throughout the test year. As such, the energy savings associated with these measures were not seen in the test year months prior to the completion of the measures. Therefore, an annualization adjustment to each month is needed to ensure that test year

[2] The New Mexico Public Regulation Commission ("NMPRC") also requires energy efficiency programs to be measured and verified by a NMPRC-appointed EM&V Evaluator.

[3] See Schedule N-6. An Errata was filed April 28, 2021. The 2020 savings remained unchanged from April 1, 2021 filing.

data reflects twelve months at full participation levels. For example, the test year data needs to reflect twelve months of energy savings for that customer that completed the energy efficiency measures during the last month of the test year.

Q. IS THE COMPANY SEEKING ANY RECOVERY OF REVENUE LOST FROM ENERGY EFFICIENCY PROGRAMS IN THIS RATE CASE?

A. No. The Company is simply making an adjustment to its billing determinants to reflect the impact of the energy efficiency programs during the test year. It is not a lost revenue adjustment mechanism as Mr. Johnson suggests in his direct testimony. Lost revenue recovery mechanisms seek to determine and recover the cumulative amount of revenue foregone or lost from energy efficiency programs over a period of time. These programs are generally applied to a period of years occurring between rate cases and seek to recover all revenues lost during the applicable time period. This is not what EPE is proposing. Instead, the Company is simply seeking to adjust its billing determinants for the test year as if the energy efficiency programs implemented during that year had been in place throughout the entire test year. Again, this is similar to the year-end customer annualization adjustment discussed in my direct testimony.

Q. MR. JOHNSON DISCUSSES A CENTERPOINT CASE IN WHICH THE COMMISSION CONCLUDED THAT SECTION 39.905 OF THE PUBLIC UTILITY REGULATORY ACT ("PURA") DID NOT ALLOW FOR A LOST REVENUE ADJUSTMENT MECHANISM. IS THE COMPANY'S PROPOSED REVENUE ADJUSTMENT BEING MADE PURSUANT TO SECTION 39.905 OF PURA?

A. No. The energy efficiency adjustment is a revenue annualization designed to make test year billing determinants accurate for ratemaking purposes. The annualization does not rely on Section 39.905 of PURA and is not a request for recovery of lost revenue, as I explained above. As such, EPE's proposed adjustment is not similar to the CenterPoint case discussed by Mr. Johnson in his testimony.

Q. IS THE COMPANY'S PROPOSED ENERGY EFFICIENCY ANNUALIZATION ADJUSTMENT DIFFERENT IN OTHER RESPECTS FROM THE ADJUSTMENT PROPOSED BY CENTERPOINT IN THE CASE CITED BY MR. JOHNSON?

A. Yes. EPE's adjustment is considerably different than the CenterPoint case, because CenterPoint's proposal was not limited to its test year billing determinants. In Docket No. 38339, CenterPoint proposed to adjust revenues not only for its test year, but for two future years. As CenterPoint's post-hearing brief summarized it at pp. 183-184, "the adjustment actually consist[ed] of the impact on billing determinants for 2009, 2010, and 2011." Because it involved future time periods, it necessarily involved projections about those future periods. As I have explained, EPE is seeking only to adjust test year billing determinants using actual energy savings associated with completed energy efficiency measures. It is also worth noting that the CenterPoint case was decided prior to the establishment of the Commission's statewide EM&V contractor and the Commission-approved Technical Reference Manual. Based on these facts, discussion of the CenterPoint case is not applicable to EPE's proposed annualization.

Q. WHAT IS YOUR CONCLUSION WITH REGARD TO MR. JOHNSON'S PROPOSAL IN THIS MATTER?

A. The energy efficiency annualization adjustment is not a lost revenue adjustment mechanism, as I have not quantified any lost revenue in my testimony that EPE is seeking to recover. The adjustment is based on "known and measurable" (i.e., PUCT-appointed EM&V contractor verified) values documented in EPE's filed 2021 EEPR. Additionally, the similarity between the customer year-end annualization and the energy efficiency annualization makes them conjunctively subject to acceptance or rejection.

As previously mentioned, the energy efficiency adjustment is based on EM&V verified energy savings using the rate-making principle of annualization. Therefore, the proposal to reject the energy efficiency annualization adjustment by Mr. Johnson should be rejected. If not, then EPE's proposed customer year-end annualization adjustment should be rejected as well, since that adjustment also uses the rate-making principle of "annualization."

Q. MR. JOHNSON IS PROPOSING A FIRM BASE REVENUE DISTRIBUTION WHICH INCLUDES MODERATION. HOW DO YOU RESPOND TO THAT PROPOSAL?

A. Mr. Johnson is proposing that, under the Company's proposed revenue requirement, two rate moderation tools be applied: (1) increases are capped at 140% of the system average percentage increase, and (2) no class receives a revenue reduction. Under his proposal, eight rate classes, including the Residential Service rate class, would get a 10.56% increase; four rate classes would get 0% change in revenue; and the remaining five rate classes receive an increase between these two percentages. As several parties in this proceeding have indicated, the Commission attempts to ensure that rates either reflect the full cost-of-service or make progress toward reaching unity with costs. Mr. Johnson's proposal counters what the Commission attempts to ensure. However, his proposal about no revenue decreases given the overall increase the Company has requested, has merit. Please see Exhibit MC-2R for a comparison of CEP's proposal against the other proposed revenue increase distributions in this proceeding.

Q. MR. JOHNSON RECOMMENDS INCREASING EPE'S PROPOSED INTERRUPTIBLE BASE REVENUE INCREASE BY $1.388 MILLION. DOES THE COMPANY AGREE TO SUCH ADDITIONAL INCREASE?

A. No. Mr. Johnson is proposing a total increase to Rate 38 base revenue that equates to more than 5 times the system average increase (a 41% increase in revenue). The Company finds Mr. Johnson's proposal unreasonable and recommends that the Commission reject such proposal as it may result in interruptible rates that are uneconomically viable for current customers to remain in the interruptible program and to attract new customers to EPE's proposed expansion of the program.

Q. IN YOUR OPINION, CAN THE PROPOSED INTERRUPTIBLE RATE BE CONSIDERED A DISCOUNT RATE PURSUANT TO PURA SECTION 36.007, AS MR. JOHNSON SUGGESTS?

A. Rate Schedule No. 38 - Notice Interruptible Service is specifically for interruptible service, not to provide discounted firm service. The interruptible demand charges of this rate schedule are determined by applying a credit calculated using avoided cost of a peaking

generating plant as a proxy for such costs. Prior to adjusting for demand losses, the moderated incremental generation cost in this filing was calculated to be $13.80 per kW (see WP/Q 7(a)). According to Schedule P-6, the demand unit cost of EPE's production function for Large Power Service is $13.317 per kW. EPE's avoided generation capacity cost that the interruptible credits are based on is reasonably close to the generation portion of the demand unit costs.

According to the Commission's conclusions of law in Docket No. 37173, interruptible credits above the generation portion of demand unit costs are not specifically prohibited by PURA or Commission rules. I am not an attorney and am not making any legal interpretations, however, in my opinion; it is evident that EPE's proposed interruptible rate is not a discount rate pursuant to PURA Section 36.007.

Q. IS MR. JOHNSON'S RESIDENTIAL CUSTOMER CHARGE COMPARISON VALID?

A. No. His comparison in his Schedule CJ-9 mixes ERCOT and non-ERCOT utilities. The proper comparison is among EPE's peer traditional vertically integrated utilities, the non-ERCOT utilities.

Q. MR. JOHNSON RECOMMENDS THAT THE RESIDENTIAL SERVICE CUSTOMER CHARGE REMAIN AT THE CURRENT $8.25 MONTHLY RATE OR, AT MAXIMUM, THAT IT NOT BE INCREASED MORE THAN THE PERCENTAGE INCREASE IN TOTAL RETAIL BASE REVENUE ALLOWED BY THE COMMISSION. DO YOU FIND THIS PROPOSAL REASONABLE?

A. No. As I indicated in my direct testimony, increasing customer charges to full cost of service reduces intra-class subsidies and improves the accuracy of the price signal provided by other charges. Additionally, the proposed Residential Service customer charge represents approximately 12% of the base rate charges. The customer charge representation is lessened further when other rates (*e.g.*, fuel charges) are considered when calculating the total customer bill. Therefore, residential customers have a significant portion of their bill that they can control in taking power conservation measures.

Mr. Johnson's proposal that the monthly customer charge remain at its current level of $8.25 per month is not supported by any analysis nor is it cost-based. His suggestion

that if it is determined that the customer charge move towards full cost of service, that it should not be increased more than the percentage increase in total retail base revenue allowed by the Commission is also not supported by any analysis nor is it cost-based.

Q. MR. JOHNSON RECOMMENDS THE SHORTENED SUMMER MONTH DEFINITION THAT EPE IS PROPOSING SHOULD BE REJECTED BECAUSE THE COMPANY HAS NOT PRODUCED SUFFICIENT ANALYSIS TO SUPPORT ITS POSITION. PLEASE RESPOND.

A. As I discuss in my direct testimony, a 4-month summer season better aligns the proposed pricing structure with EPE's summer season and system peak hours and supports the 4CP-based allocators used for assignment of generation and transmission costs in EPE's cost of service studies.

Not aligning the rates to the peak months would result in the rates not providing the strong price signals that they are intended to convey to customers, resulting in a mediocre effect on changing the customers' consumption behavior. Achieving significant peak demand reduction requires sending a meaningful price signal that customers can respond to. A shortened summer season, in conjunction with EPE's proposal to increase the price differentials of the summer energy charges, will help achieve that goal. EPE encourages the Commission to take a more assertive approach at helping the Company reduce peak demand and improve its system load factor.

Q. MR. JOHNSON RECOMMENDS THAT EPE'S PROPOSAL TO DOUBLE THE PRICE DIFFERENTIAL FOR THE SUMMER ENERGY CHARGES BE REJECTED BECAUSE THE COMPANY HAS NOT PRODUCED SUFFICIENT ANALYSIS TO SUPPORT ITS POSITION. HOW DO YOU RESPOND?

A. I am sure Mr. Johnson is aware that rate design often requires professional judgement over analysis when attempting to meet certain objectives, such as peak demand reduction and energy conservation.

As discussed above, achieving significant peak demand reduction requires sending a meaningful price signal that customers can respond to. The declining system load factor that EPE has been experiencing indicates that the current rate structures and price

differentials are not sending strong enough signals. The price differentials in the energy charges that EPE is proposing in this proceeding will help the Company achieve that goal.

Q. WHEN WAS THE SCHEDULE NO. 01 QUALIFIED WATER CONSERVATION AIR COOLING RIDER CLOSED TO NEW CUSTOMERS?

A. This rider, which Mr. Johnson alludes to in his testimony, was closed to new customers effective July 1, 2010 because it did not send an appropriate pricing signal to encourage energy conservation. The rider provided a half cent price differential, with all summer month energy consumed in excess of 1,000 kWh benefiting from that differential. The rider was eliminated from Schedule No. 01 effective April 2016. Customers with refrigerated air conditioning units are encouraged to research EPE Energy Efficiency programs, which can help customers find ways to conserve electricity and become more energy efficient.

Q. MR. JOHNSON OPINES THAT EPE'S INCREMENTAL GENERATION COSTS, WHICH ARE USED IN RATE DESIGN, OVERSTATE THE COST OF AVOIDING GENERATION CAPACITY COSTS. HOW DO YOU RESPOND?

A. In my direct testimony, I discuss that in EPE's most recent rate cases in Texas and New Mexico, EPE relied on the costs for the Rio Grande Unit 9 combustion turbine to estimate the incremental capacity cost used in rate design, and thus, EPE used that unit's levelized costs in this base rate case filing for consistency purposes. I also explain that the percentages of EPE's incremental capacity cost by class that the Time-of-Day ("TOD") on-peak period energy price adders are based on are a part of EPE's tools in its rate design process. Except for the EV charging rate design, the incremental capacity cost used in rate design is moderated to some extent by the application of these percentages. In my direct testimony I further explain in balancing gradualism and the intent to influence certain consumption behaviors, it is necessary that those percentages differ among rate classes. If the percentages are set too high, rate shock is introduced and if the percentages are set too low then the intended effect of the on-peak period charges will be insufficient.

If EPE was to use any of the other incremental generation capacity costs that Mr. Johnson lists in page 44 of his testimony, that would simply require that higher

percentages of those unit costs be used to achieve the desired results in rate design. Mr. Johnson's recommendation about what incremental generation capacity cost should be used for rate design should be disregarded. Continuing to use Rio Grande Unit 9 is consistent with what EPE has used in previous rate design studies and provides a better comparison as the percentages applied to the cost are adjusted in EPE's ongoing rate design studies.

Q. MR. JOHNSON SUGGESTS THAT EPE'S PROPOSED RESIDENTIAL ON-PEAK PRICES ARE POTENTIALLY TOO HIGH. HOW DO YOU RESPOND?

A. Mr. Johnson does not provide any analysis or support that shows that EPE's on-peak prices are "potentially" high. He also recommends to the Commission that it should consider "tempering" the TOD rate impact, but also offers no analysis of what tempered on-peak prices are.

As indicated in my testimony, EPE's proposed TOD price signals for residential customers are in line with many other time variant rate offerings in the country and provide a reasonable economic incentive for customers to consider participation in the TOD rate offering and to change their usage patterns. Achieving significant peak demand reduction requires sending a meaningful price signal that customers can respond to. EPE encourages the Commission to take a more assertive approach at helping the Company reduce peak demand and improve its system load factor. EPE's proposed TOD rates will help the Company achieve this goal.

Q. IS EPE AMENABLE TO MR. JOHNSON'S RECOMMENDATION REGARDING THE EXPANSION OF THE RATE 24 MANDATORY TOD SCHEDULE FOR NEW CUSTOMERS?

A. No. Mr. Johnson recommends that instead of the 200 kW threshold for mandatory TOD rates, the threshold should be 300 kW. He states that customers subject to the 200 kW threshold may have limited or even no ability to reduce usage during peak hours, but does not provide any evidence to support this statement. EPE's experience with the current 400 kW threshold shows that very few Rate 24 customers opted out of the TOD rate since the threshold was implemented.

He also recommends that new customers subject to the threshold be permitted to change to the standard rate after six months on TOD, instead of twelve months as proposed by the Company. Mr. Johnson fails to reference the remainder of the hold harmless clause in the proposed rate schedule which states that "If, at the conclusion of the initial twelve (12) month period of service under the Alternative TOD rate, the total billings for the 12-month period exceed billings for the same period under the Standard Service rate, the Customer may opt to revert to the Standard Service rate. In this event, the Company will reset the Customer's account to the Standard Service rate and credit the Customer for the difference in billings under the Alternative TOD rate and the Standard Service rate for the initial 12-month review period." For a customer to see the full effect of being on the TOD rate, it is necessary that the billings cover an entire twelve-month period.

For these reasons, the Commission should reject Mr. Johnson's recommendations regarding setting the 300 kW threshold of the Rate 24 mandatory TOD rate for new customers and to allow customers to switch to the standard rate after six months on the TOD rate.

IV. Recommendations by DOD/FEA Witness Blank

Q. IN THE DIRECT TESTIMONY OF DOD/FEA WITNESS LARRY BLANK, HE CONTENDS THAT EPE HAS NOT FULLY ACCOUNTED FOR THE BILLING DETERMINANTS UNDER RATE 31. HOW DO YOU RESPOND?

A. I concur with the DOD/FEA witness Blank that the Rate 31 billing determinants does not reflect the change in the firm contract demand from 46,000 to 51,000 kW. This was an oversight by EPE and is corrected in the Company's rebuttal schedules and exhibits.

Q. HOW DOES THIS OVERSIGHT IMPACT EPE'S COST OF SERVICE STUDY?

A. The correction of this oversight impacts EPE's cost-of-service studies in two ways: (1) net energy sales, in kWh, which are used in calculating energy-based jurisdictional and class allocation factors, have increased for the Texas jurisdiction and the Rate 31 rate class, resulting in additional cost allocated to the Texas jurisdiction and to Rate 31, (2) the net revenue at present rates have increased for both the Texas jurisdiction and the Rate 31 rate

class. Both impacts are now included in the cost-of-service studies discussed by EPE witness Hernandez in his rebuttal testimony.

Q. PLEASE EXPLAIN WHAT IS MEANT BY "NET ENERGY SALES" AND "NET REVENUE."

A. Because of the change in the firm contract demand, the increase in the firm billing demand results in an increase in firm billing energy which is offset by a decrease in the interruptible billing energy, resulting in net energy sales. Similarly, the increase in the firm billing determinants caused an increase in firm revenue which were met by a decrease in interruptible revenue due to the decrease in the interruptible billing determinants, resulting in net revenue.

Q. DO YOU ALSO CONCUR WITH THE AMOUNT OF ADDITIONAL REVENUE THAT MR. BLANK CALCULATED?

A. No. EPE flowed the new firm contract demand (at 51,000 kW) through its Texas annualization model (originally provided as OPUC 1-11 Attachment 1 Voluminous) and derived a slightly lower additional revenue amount for Rate 31, at $1,363,112 as compared to Mr. Blank's $1,451,566. Additionally, the model showed that Rate 38 interruptible revenues decreased by $170,616. Mr. Blank did not perform a calculation for the change in interruptible revenues. The Texas jurisdiction base revenue, therefore, has increased by $1,192,496 due to this correction.

Q. DOES EPE FIND MR. BLANK'S RECOMMENDED CHANGE TO THE CONTRACT TERM LANGUAGE FOUND WITHIN THE SCHEDULE NO. 38 RATE SCHEDULE REASONABLE?

A. No, for three reasons. First, EPE is not required to file power service agreements with the Commission, unless the Commission requests the filing. Second, EPE has consistently worked with its interruptible customers on any change in service, within the terms of the power service contract. Finally, as EPE has indicated in this filing, it is proposing to expand the interruptible service program, not decrease it. Therefore, Mr. Blank's recommendation to change the Rate 38 rate schedule would set up an unnecessary and

costly process that would burden both the Company and the Commission and should be rejected.

V. Recommendations by FMI Witness Pollock

Q. FMI WITNESS JEFFERY POLLOCK DEVELOPED AN ALTERNATIVE CLASS REVENUE ALLOCATION BASED ON FMI'S REVISED CLASS COST-OF-SERVICE STUDY. HOW DO YOU RESPOND?

A. FMI suggests that, except for the capping of the Water Heating Service rate class increase at 43%, no moderation be applied for all the other rate classes. EPE does not agree that the Commission should take FMI's suggested rigid approach in this proceeding, particularly because of the pandemic environment that EPE's most vulnerable customers, its residential customers, are currently under. That approach will result in much higher rates for residential customers than those proposed by EPE and all other parties to this proceeding. Please see Exhibit MC-2R for a comparison of TIEC's proposal against the other proposed revenue increase distributions in this proceeding.

Q. MR. POLLOCK RECOMMENDS THAT THE RATE 15 ON-PEAK ENERGY CHARGE REMAIN UNCHANGED AND THAT THE SUMMER DEMAND CHARGE BE 20% MORE THAN THE INCREASE IN THE NON-SUMMER DEMAND CHARGE. IS EPE AMENABLE TO THIS RECOMMENDATION?

A. Yes, but only if the resulting rate design fully recovers the revenue requirement assigned to Rate 15 and provides a price signal to reduce power demands during the summer on-peak period.

Q. MR. POLLOCK ALSO RECOMMENDS THAT THE RATE 15 MINIMUM CONTRACT CAPACITY BE REDUCED FROM 7,500 KW TO 5,000 KW. IS EPE AMENABLE TO THAT RECOMMENDATION?

A. Yes, but only if the final rate design in this proceeding, with billing determinants reflecting the 5,000 kW level, fully recovers the revenue requirement assigned to Rate 15 and provides a price signal to reduce power demands during the summer on-peak period. The interruptible power service agreement between Mr. Pollock's client in this proceeding and

EPE will need to be revised to effectuate the new 5,000 kW contract capacity specified in the Schedule No. 15 rate schedule approved by the Commission in this proceeding.

VI. Recommendations by OPUC Witness Evans

Q. OPUC WITNESS EVAN D. EVANS IS PROPOSING A MODERATION APPROACH FOR THE BASE REVENUE INCREASE DISTRIBUTION AMONG CUSTOMER CLASSES. HOW DO YOU RESPOND?

A. I have three concerns with Mr. Evans' proposal. My first concern is that he proposes that the base revenue increase distribution among customer classes reflect moderation, however no analysis was provided to determine if the proposed distribution will fully allow for the recovery of EPE's revenue requirement. My second concern is, because of the pandemic environment that EPE's most vulnerable customers, its residential customers, are currently under, that proposal will result in higher rates for residential customers than those proposed by EPE. Finally, as several parties in this proceeding have indicated, the Commission attempts to ensure that rates either reflect the full cost-of-service or make progress toward reaching unity with costs. Mr. Evans' proposal counters what the Commission attempts to ensure. However, his proposal about no revenue decreases given the overall increase the Company has requested, has merit. Please see Exhibit MC-2R for a comparison of OPUC's proposed revenue increase distribution compared to the other proposed revenue increase distributions in this proceeding.

Q. MR. EVANS RECOMMENDS THAT THE RESIDENTIAL SERVICE CUSTOMER CHARGE REMAIN AT ITS CURRENT LEVEL OR, AT MAXIMUM, THAT IT NOT BE INCREASED MORE THAN THE AVERAGE BASE RATE INCREASE FOR THE RESIDENTIAL SERVICE CLASS. DO YOU FIND THIS PROPOSAL REASONABLE?

A. No. As I indicated in my direct testimony, increasing customer charges to full cost of service reduces intra-class subsidies and improves the accuracy of the price signal provided by other charges. Additionally, the proposed Residential Service customer charge represents approximately 12% of the base rate charges. The customer charge

representation is lessened further when other rates (*e.g.*, fuel charges) are considered when calculating the total customer bill.

Mr. Evans' proposal that the monthly customer charge remain at its current level of $8.25 per month is not supported by any analysis. His concerns about customer impacts on low usage customers and future implementation of customer charges for advanced metering are not sufficient to warrant setting a charge that is not cost based. His suggestion that if it is determined that the customer charge move towards full cost of service, that it should not be increased more than the average base rate increase for the Residential Service class is also not supported by any analysis nor is it cost-based.

Q. MR. EVANS EXPRESSES HIS CONCERN ABOUT THE SHORTENED SUMMER PERIOD THAT EPE IS PROPOSING. HOW DO YOU RESPOND?

A. As I discuss in my direct testimony, a 4-month summer season better aligns the proposed pricing structure with EPE's summer season and system peak hours and supports the 4CP-based allocators used for assignment of generation and transmission costs in EPE's cost-of-service studies. In his testimony, Mr. Evans supports the use of a 4CP-based allocator, which uses the four peak months (June-September) that EPE is proposing for its Residential Service rate schedule.

Not aligning the rates to the peak months would result in the rates not providing the strong price signals that they are intended to convey to customers, resulting in a mediocre effect on changing the customers' consumption behavior. Achieving significant peak demand reduction requires sending a meaningful price signal that customers can respond to. A shortened summer season, in conjunction with EPE's proposal to increase the price differentials of the summer energy charges, will help achieve that goal. EPE encourages the Commission to take a more assertive approach at helping the Company reduce peak demand and improve its system load factor.

Q. MR. EVANS RECOMMENDS THAT EPE'S PROPOSAL TO DOUBLE THE PRICE DIFFERENTIAL FOR THE SUMMER ENERGY CHARGES BE REJECTED BECAUSE THEY ARE NOT BASED ON ANY ANALYSIS OR CALCULATION AND THEY ARE ESSENTIALLY AERIAL EXTRACTIONS. HOW DO YOU RESPOND?

A. I'm sure that Mr. Evans is aware that rate design often requires professional judgement over analysis when attempting to meet certain objectives, such as peak demand reduction and energy conservation.

As discussed above, achieving significant peak demand reduction requires sending a meaningful price signal that customers can respond to. The declining system load factor that EPE has been experiencing indicates that the current rate structures and price differentials are not sending strong enough signals. The price differentials in the energy charges that EPE is proposing in this proceeding will help the Company achieve that goal.

Q. MR. EVANS SUGGESTS EPE DID NOT PREPARE ANY ANALYSES TO SHOW THE IMPACT OF THE CHANGE IN SEASONS OR RATES ON RESIDENTIAL CUSTOMERS. DO YOU AGREE WITH THIS STATEMENT?

A. No. In EPE's response to OPUC 7-8, which is attached to his testimony as Attachment EDE-11, is a list of analyses is presented in which the impact to the Residential Service monthly bills at varying levels of consumption was computed. However, Mr. Evans failed to identify that part of the response in his direct testimony.

Q. DID EPE INFORM ITS CUSTOMERS ABOUT THE PROPOSED CHANGES TO ITS RATES AND DOES THE COMPANY INTEND TO INFORM THEM WHEN FINAL RATES ARE DETERMINED?

A. Yes. In compliance with PURA § 36.103, 16 Tex. Admin. Code ("TAC") § 22.51(a), and 16 TAC § 25.235(b), newspaper publication of the Notice of El Paso Electric Company's Petition to Change Rates was completed by August 13, 2021 after it had been published once a week for four weeks. Individual notice of the Notice was mailed on August 25, 2021. That notice was provided to residential customers in both English and Spanish. Notice to parties to EPE's last rate case was sent on June 1, 2021

Furthermore, EPE's response to OPUC 7-11, which Mr. Evans attached to his testimony as Attachment EDE-12, states the Company has not *to date* developed communications for its residential customers (emphasis added). As the rate case proceeding progresses and finalizes, then EPE will know exactly what needs to be

communicated to its customers using several mediums. However, Mr. Evans failed to identify that part of the response in his direct testimony.

Q. MR. EVANS STATES THAT NO SUPPORTING TESTIMONY WAS PROVIDED FOR THE INCREASE IN THE OFF-PEAK WATER HEATING RIDER CUSTOMER CHARGE. HOW DO YOU RESPOND?

A. In his testimony, Mr. Evans states that "EPE's rate design witness, Mr. Manny Carrasco indicates that the $4.84 is the full cost. However, Mr. Carrasco provides no other testimony supporting this significant increase." To reiterate what I stated in my direct testimony, my testimony is that the Off-Peak Water Heating Service Rider customer charge is priced at full cost of service, which is $4.84 per month.

Mr. Evans recommended increase in the Water Heating Rider customer charge be limited to 1.5 times the average base rate increase is, like his other recommendations for both Residential and Small General Service rates, not cost-based or supported by any analysis. Those recommendations should be rejected.

VII. Recommendations by RATE 41 Group Witness Daniel

Q. THE RATE 41 GROUP WITNESS JAMES W. DANIEL CLAIMS THAT THE ACCOUNTS IN THE RATE 41 CUSTOMER CLASS HAVE HISTORICALLY RECEIVED A RATE DISCOUNT. IS THAT YOUR UNDERSTANDING AS WELL?

A. No. According to PURA Section 36.351, a rate discount is available to any facility of any four-year state university or upper-level institution. EPE complies with this requirement through its Schedule No. 49 – State University Discount Rate Rider, which is applied to several accounts. None of those accounts, however, are billed under Rate 41. Furthermore, El Paso Community College, which Mr. Daniel refers to in his testimony, is not considered a state university or upper-level institution and does not qualify for Schedule No. 49's 20% discount.

Mr. Daniel's testimony is confusing because, on page 11, he makes the unsupported claim that the 'discount' has historically been in effect for Rate 41 customers, and then, on page 12, he states that he is proposing that the Commission adopt a discount for Rate 41 like those provided for higher education and for military bases. Mr. Daniel's proposal for

a discount to governmental entities would be better addressed by a statutory change and should be disregarded in EPE's current rate case proceeding.

Q. MR. DANIEL ALSO CLAIMS THAT THERE IS DOUBLE ALLOCATION OF THE SUBSIDY PAID BY FLOOR CUSTOMER CLASSES. IS THAT YOUR UNDERSTANDING AS WELL?

A. No. As explained in my direct testimony, EPE redistributed the excess revenue, after applying the cap and floor, to all rate classes proportional to their combined total revenue.

Q. MR. DANIEL DEVELOPED A PROPOSED REVENUE DISTRIBUTION BASED ON HIS CORRECTION FOR HIS PROPOSED DISCOUNT TO THE RATE 41 RATE CLASS AND THE DOUBLE ALLOCATION OF THE SUBSIDY PAID BY THE FLOOR CUSTOMER CLASSES. DO YOU AGREE WITH HIS REVENUE DISTRIBUTION?

A. No, but only because of the discount that he suggests for the Rate 41 rate class. His proposal about not assigning revenue decreases given the overall increase the Company has requested, has merit. However, because of the pandemic environment that EPE's most vulnerable customers, its residential customers, are currently under, that proposal will result in higher rates for residential customers than those proposed by EPE. Please see Exhibit MC-2R for a comparison of RATE 41 Group's proposal against the other proposed distributions in this proceeding.

Q. MR. DANIEL DISCUSSES IN HIS TESTIMONY THAT EPE HAS NOT DEMONSTRATED THAT A POWER FACTOR ADJUSTMENT IS NEEDED FOR RATE 41. HAS EPE DEMONSTRATED THIS?

A. Yes. It was in response to a request for information from the RATE 41 Group that EPE demonstrated that some Rate 41 customers have significant power factor issues which are negatively impacting EPE's local distribution system.[4] Under the current Rate 41 tariff schedule, such low power factor customers are benefiting at the expense of other customers served with the same local distribution system.

[4] See EPE's supplemental response to RATE 41 1-6.

Q. MR. DANIEL ALSO DISCUSSES IN HIS TESTIMONY THAT EPE HAS NOT DEMONSTRATED THE ADDITIONAL ANNUAL REVENUES FROM THE POWER FACTOR ADJUSTMENT 41. HAS EPE CALCULATED THESE ADDITIONAL REVENUES?

A. No, because EPE expects that customers with low power factors will be incentivized by the possible imposition of the power factor adjustment penalty to improve the power factor by installing equipment, such as capacitors, on their side of the meter. However, in response to a request for information from the RATE 41 Group, EPE calculated the additional revenue if Rate 41 customers do not make power factor correction measures. That penalty could amount up to $626,000 per year for the entire class.[5]

Q. MR. DANIEL SUGGESTS THAT THE COMMISSION POSTPONE (AT LEAST ONE YEAR) THE IMPLEMENTATION OF THE RATE 41 POWER FACTOR ADJUSTMENT TO GIVE CUSTOMERS THE OPPORTUNITY TO BUDGET FOR AND INSTALL CAPACITORS TO CORRECT LOW POWER FACTORS. IS EPE AMENABLE TO THIS SUGGESTION?

A. No. EPE will agree, however, to provide a credit on the customer's bill equal to the amount of the power factor penalty for a period of one year. This will allow the customer to realize the cost of not improving the power factor but will be held harmless from that charge for that one-year period.

VIII. Recommendations by TIEC Witness Higgins

Q. WHAT IS YOUR VIEW ON TIEC'S RECOMMENDATION THAT ALL TEXAS RATE CLASSES BE MOVED TO FULL COST OF SERVICE?

A. EPE does not agree that the Commission should take TIEC's suggested rigid approach in this proceeding, particularly because of the pandemic environment that EPE's most vulnerable customers, its residential customers, are currently under. That proposal will result in much higher rates for residential customers than those proposed by EPE. Please

[5] *Id.*

see Exhibit MC-2R for a comparison of TIEC's proposed revenue increase distribution compared to the other proposed revenue increase distributions in this proceeding.

Q. DOES EPE FIND MR. HIGGINS' RECOMMENDED CHANGE TO THE APPLICABILITY PROVISION LANGUAGE FOUND WITHIN THE SCHEDULE NO. 25 RATE SCHEDULE REASONABLE?

A. No. The rate design proposed for EPE's rate schedules (except Rate 41) is based on homogenous load or end-use characteristics of the customers within each rate class. Opening Rate 25 to any large load customer may result in a mismatch of rates to cost.

IX. Recommendations by UTEP Witness Pevoto

Q. UTEP WITNESS KIT PEVOTO HAS PROPOSED A RATE CLASS BASE RATE REVENUE REQUIREMENT DISTRIBUTION WHICH INCLUDES MODERATION. HOW DO YOU RESPOND TO THAT PROPOSAL?

A. Ms. Pevoto's revenue requirement distribution has merit. However, because of the pandemic environment that EPE's most vulnerable customers, its residential customers, are currently under, that proposal will result in higher rates for residential customers than those proposed by EPE. Please see Exhibit MC-2R for a comparison of UTEP's proposed revenue increase distribution compared to the other proposed revenue increase distributions in this proceeding.

X. Recommendations by VS Witness Stanley

Q. PLEASE RECONCILE THE 7.79% OVERALL PROPOSED SYSTEM BASE RATE INCREASE IN THE DIRECT TESTIMONY OF VINTON STEEL WITNESS STANLEY TO THE 7.38% EPE USED IN SETTING THE CAP FOR CERTAIN RATE CLASSES?

A. The 7.79% that Mr. Stanley references is also described on page 14 of my direct testimony and is the increase in base rate revenue prior to separating out the increase in non-firm revenue and the proposed COVID-19 surcharge. After separating out those amounts, the remaining increase amounts to the 7.38% used by EPE to impose the 11.07% cap for the Residential Service and Water Heating rate classes.

Q. EPE HAS NOT PROPOSED TO CAP ALL RATE CLASSES FOR WHICH ITS COST-OF-SERVICE STUDY INDICATES A REVENUE INCREASE. IS THAT CONSISTENT WITH COMMISSION GOALS?

A. Yes. Several parties in this proceeding have indicated in testimony that the Commission attempts to ensure that rates either reflect the full cost-of-service or make progress toward reaching unity with costs. By not applying an across-the-board cap, EPE's proposed revenue increase distribution is in unison with Commission goals.

Q. DID ANY VINTON STEEL WITNESS PROPOSE A REVENUE DISTRIBUTION IN TESTIMONY?

A. No. In the direct testimony of Vinton Steel witness Stanley, the recommendation is made that in the distribution of the final revenue increase that no class incur a percentage base rate revenue increase that is more than 1.5 times the jurisdictional average. Without further analysis using Mr. Stanley's capping proposal or how he would recommend any remaining revenue deficiency after applying the cap should be allocated, it is difficult to determine if the resulting distribution will fully allow for the recovery of EPE's revenue requirement. Please see Exhibit MC-2R for a comparison of Vinton Steel's proposal, as I understood it, compared to the other proposed revenue increase distributions in this proceeding.

Q. MR. STANLEY CRITICIZES THE RATE 38 ENERGY CHARGES BECAUSE THEY ARE SET EQUAL TO THE OFF-PEAK ENERGY CHARGE OF THE RATE 25 SCHEDULE. HOW DO YOU RESPOND?

A. Mr. Stanley correctly states in his testimony that there is no separate class of service for Rate 38 in EPE's cost-of-service study. Lacking a separate rate class, it is necessary to use costing information from another rate class as a proxy for the Rate 38 rate design; EPE has selected Rate 25 for this purpose. Most interruptible service customers receive their service through a combination of the Rate 25 and Rate 38 tariff schedules. In its proposed expansion of Rate 38, EPE expects the additional capacity will come from customers that are billed for service through Rate 25. Therefore, it is reasonable to base the Rate 38 energy charges (and demand charges) using pricing and cost information from Rate 25.

Mr. Stanley criticizes the use of the Rate 25 off-peak energy charge as the Rate 38 energy charge but offers no reasonable solution to how the interruptible service energy charge should be determined. In fact, his non-cost-based recommendation that the same percentage change be applied equally to the interruptible demand and energy charges contradicts his testimony on page 16 that the electrical power to Rate 38 customers is a much lower quality of service as compared to power served under EPE's other firm rates (thus suggesting lower pricing for interruptible service as compared to the Rate 25 firm service).

EPE is proposing reasonable, cost-based energy and demand charges for its interruptible service. Mr. Stanley's recommendation for an across-the-board adjustment to the interruptible service rate design is not cost-based and should be rejected by the Commission.

XI. Recommendations by Walmart Witness Teague

Q. DID EITHER OF THE WALMART WITNESSES PROPOSE A REVENUE INCREASE DISTRIBUTION?

A. No, however, in page 14 of his direct testimony, Walmart witness Teague indicates that Walmart does not oppose the Company's revenue allocation moderation proposal.

Q. MR. TEAGUE MAKES SEVERAL RECOMMENDATIONS ON THE RATE DESIGN FOR SCHEDULES NOS. 24 AND 25. HOW DO YOU RESPOND TO HIS RECOMMENDATIONS?

A. For Schedule No. 24, Mr. Teague recommends that EPE's proposed charges and structural changes to time-of-day be accepted, the current demand charges for summer and non-summer be maintained, and to use the revenue requirement reduction to reduce the energy charges. The Company is amenable to set the demand charge at approximately the current levels and to balance out the revenue requirement with a commensurate reduction to the energy charge, but only if the resulting rate design fully recovers the final revenue requirement assigned to Rate 24 and provides a price signal to reduce power demands during the summer on-peak period. Note, however, that Mr. Teague, in his testimony, expresses concern about the energy charge rate structure discouraging high load factor

customer from energy conservation measures as they will only conserve the cheapest energy under that structure, yet he advocates for reduced energy charges.

For Schedule No. 25, Mr. Teague recommends that as the revenue requirement decreases, any reduction should be taken from the energy charge. The Company is also amenable to this, but only if the resulting rate design fully recovers the final revenue requirement assigned to Rate 25 and provides price signals to reduce power demands during the summer on-peak period.

XII. Recommendations by Staff Witnesses Abbott, Stark, and Narvaez

Q. STAFF WITNESS ABBOTT CONTENDS THAT IT IS UNREASONABLE FOR THE DISTRIBUTED GENERATION ("DG") MINIMUM BILL TO DECREASE WHEN EPE IS REQUESTING AN INCREASE IN RESIDENTIAL RATES. PLEASE RESPOND.

A. Lacking a separate Residential DG rate class, EPE's proposed DG Minimum Bill is based on pricing and unit cost information within the Residential Service rate class (which includes both DG and non-DG customers), thus making it just and reasonable and not unreasonably preferential, prejudicial, or discriminatory.

In EPE's last base rate case, Docket No. 46831, Staff witness Abbott supported how the demand charge was calculated by EPE, as he notes in his testimony from Docket No. 46831 attached as workpapers to his testimony in the current rate case. In the current rate case, EPE calculated the demand charge, which supports the DG Minimum Bill charge EPE proposes, in the same manner as in EPE's last base rate case. The proposed DG Minimum Bill charge, then, is cost-based.

The currently effective Commission-approved DG Minimum Bill, however, was an agreed-upon amount and not fully cost-based. However, Mr. Abbott's recommendation to adjust the DG Minimum Bill amounts does have some merit. So if EPE's proposed DG Minimum Bill is not adopted, Mr. Abbott's recommendation is a reasonable alternative.

Q. STAFF WITNESS STARK EXPRESSES A CONCERN THAT BOTH INCLUDING THE COVID-19 COST AMORTIZATION IN BOTH THE COVID-19 TARIFF AND IN THE BASE RATE REVENUE REQUIREMENT RESULTS IN A

DOUBLE-RECOVERY OF THE COVID-19 REGULATORY ASSET. IS THERE A DOUBLE-RECOVERY OCCURRING?

A. No. As I discuss in section V. of my direct testimony, EPE recognized that $2.196 million of the base rate revenue increase will be provided by the proposed COVID-19 surcharge. That remainder of the revenue increase will be provided by the base rates.

In EPE's rebuttal cost-of-service study, the COVID-19 costs are fully removed, but will still be recovered through the COVID-19 surcharge. Ms. Stark's concern of a double-recovery is now a moot point.

Q. MR. NARVAEZ PROVIDES AN EXAMPLE OF HOW THE ENERGY EFFICIENCY ADJUSTMENT LEADS TO AN INCREASE IN BASE RATES. IS THAT A CORRECT EXAMPLE?

A. No. Conversely, Mr. Narvaez's example can be used to make the point why the energy efficiency adjustment is necessary. Using his numbers, if the energy efficiency adjustment is made as EPE is proposing, then the resulting rate is $0.111 per kWh. If the energy efficiency adjustment is not made, then that has the effect of decreasing rates, at $0.100 per kWh. Without this annualization adjustment, rates cannot reasonably be expected to recover the Company's revenue requirement authorized by the Commission. Without the adjustment, a greater level of billing determinants will be used to set the rates, although it is known that customers have taken energy conservation measures through EPE energy efficiency programs throughout the test year that reduced year end billing determinants. The resulting rates will not be set such that the revenues will recover the cost of service established in this proceeding. That will counter what the Commission has long adhered and known as the "matching principle."

Q. DID THE COMMISSION VERIFY THE VALUES YOU USED FOR MAKING YOUR ADJUSTMENT?

A. To clarify, the Texas energy efficiency annualization adjustment originally filed by EPE was based on achieved and unverified annual kilowatt-hour ("kWh") savings of 30,669,898 in 2020. No energy savings goals for 2021, as Mr. Narvaez inaccurately states in his testimony, were used in the adjustment calculation.

In response to the question, yes, the Commission verified the values used in making the energy efficiency annualization adjustment. On April 1, 2021, EPE filed its 2021 Energy Efficiency Plan and Report ("EEPR") with the Commission which details its achievements for 2020.[6] The achievements for 2020 in the EEPR amounted to 30,704,424 kWh in verified savings from EPE's energy efficiency programs. Those verified savings are 34,526 kWh more than what was originally used in calculating the energy efficiency annualization adjustment. The fact that the projects and associated energy savings for EPE's 2020 energy efficiency programs were verified and approved by the PUCT's EM&V contractor demonstrates that the Commission vetted these energy savings.

Q. MR. NARVAEZ CLAIMS THAT EPE'S ENERGY EFFICIENCY ANNUALIZATION ADJUSTMENT IS NOT "KNOWN" AND IS NOT "MEASURABLE" FOR INCLUSION OF AS A POST-TEST YEAR ADJUSTMENT. HOW DO YOU RESPOND?

A. To clarify, the energy efficiency annualization adjustment is not a post-test year adjustment as the intent is to annualize the impact of the energy efficiency programs that were implemented during the 2020 test year. Mr. Narvaez argues that energy efficiency savings do not comport to the Commission's known and measurable standard and that the Company has not met its burden of proof for inclusion of this post-test year adjustment. He fails to acknowledge that EPE's energy efficiency programs have historically been verified to actually achieve energy efficiency savings and, therefore, those programs are known to have happened and are measurable because the savings must meet Commission-approved criteria to be regarded as savings.

The evaluation, measurement, and verification ("EM&V") process, pursuant to 16 Texas Administrative Code ("TAC") § 25.181 ("Energy Efficiency Rule") provides, with reasonable certainty, the measurement and verification of energy and demand savings of energy efficiency programs. Those savings are documented using methods that can involve measurements, engineering calculations, statistical analyses, and/or computer simulation modeling. Mr. Narvaez, however, recommends an unquantifiable and arbitrary

[6] See Schedule N-6. An Errata was filed April 28, 2021. The 2020 savings remained unchanged from April 1, 2021 filing.

level of accuracy for these savings to be considered a "known and measurable" adjustment to the test year. His arbitrary conclusion that the effect of the energy efficiency programs is not known and measurable clearly conflicts with the Commission's stated purpose for the EM&V process, which is that "[t]he goal of this framework is to ensure that the programs are evaluated, measured, and verified using a consistent process that allows for accurate estimation of energy and demand impacts." Mr. Narvaez provides no evidence that the EM&V program has not achieved that goal. Given the effort that the PUCT-appointed EM&V contractor goes through to provide the PUCT assurances about the energy and demand savings achieved through the energy efficiency programs it approves, it is troubling to think those efforts are not sufficient to meet the burden of proof for a known and measurable adjustment as envisioned by Mr. Narvaez.[7]

Q. STAFF WITNESS NARVAEZ COMPARES THIS ADJUSTMENT TO AN ADJUSTMENT FOR YEAR END CUSTOMERS. IS THIS A VALID COMPARISON?

A. Yes. Both types of adjustments are made in order to make the test-year energy data as representative as possible of the energy sales situation prevailing at the end of the test year. The energy efficiency adjustment is akin to the adjustment for customer year-end annualization, which intends to fill in the gap between actual energy usage and a full test year of energy usage at year-end levels of customers (or participants), or in this case, energy efficiency measures installed during the test year.

Q. DID EPE PERFORM STATISTICAL TESTS IN DETERMINING THE ADEQUACY OF THE ENERGY EFFICIENCY AND CUSTOMER YEAR-END ANNUALIZATION ADJUSTMENTS?

A. No. Both adjustments are based on simple arithmetic that does not necessitate complex statistical calculations. The customer year-end annualization intends to reflect a full twelve-month period of the known customer count at year-end levels by using the monthly average use per customer measure to adjust energy sales to an annualized kWh amount. Similarly, the energy efficiency adjustment intends to annualize the impact of known

[7] The New Mexico Public Regulation Commission ("NMPRC") also requires energy efficiency programs to be measured and verified by a NMPRC-appointed EM&V Evaluator.

program participation at year-end levels. Therefore, the adjustment for the impact of energy efficiency programs is comparable to the adjustment for customer year-end annualization.

Q. COULD YOU EXPLAIN FURTHER WHY YOU CONSIDER THE ENERGY EFFICIENCY ANNUALIZATION ADJUSTMENT TO BE IN THE NATURE OF A CUSTOMER ANNUALIZATION?

A. Yes. With customer annualization, the numbers of customers at the end of a test year are assumed to have been on the system for the entire year for purposes of determining the test year billing determinants. As I said in my direct testimony, the purpose of annualizing the test year customers, revenues, sales, and demand is to adjust these items to a level representative of ongoing conditions had the number of customers at year-end been served for the entire year. For instance, if a customer became a customer in the 10th month of the test year, the annualization process would adjust the billing determinants to be equivalent to what they would have been had the customer been there for the entire year. So, in the case of a residential customer, assuming the average residential consumption is 600 kWh per month, the annualization calculation would result in there being sales of 7,200 kWh (600 kWh x 12 months) for that customer, rather than the 1,800 kWh (600 kWh x 3 months) the customer actually used during the tenth, eleventh, and twelfth month of the test year.

For comparison regarding the proposed adjustment for EPE's energy efficiency programs, an example would be a residential customer that implemented a certain EPE energy efficiency program measure that took effect in the tenth month of the test year that reduced his consumption from 600 kWh a month to 500 kWh a month. What EPE has proposed is that just like the case of the new customer who is only on the system for three months, an adjustment be made to recognize that the test year is not representative of the consumption of this customer going forward. So, the customer's usage for the first nine months is reduced by 100 kWh per month to reflect the customer's implementation of the energy efficiency measure.

For that reason, I submit that annualizing for implemented energy efficiency measures is as much a known and measurable adjustment as adjusting for the year-end number of customers, maybe more so because the savings for energy efficiency have been

verified pursuant to the Commission's Energy Efficiency Rule. In contrast, for year-end customer annualization, the annualization relies on historical averages of the energy that this type of customer uses, not specific measurements of the change in sales.

Q. PLEASE COMPARE WHEN THE COMMISSION-APPROVED RATE FILING PACKAGE ("RFP") FOR INVESTOR-OWNED UTILITIES WAS LAST REVISED AND WHEN THE PUCT'S ENERGY EFFICIENCY RULE WAS FIRST ADOPTED.

A. The RFP available in the PUCT's website shows a date of September 9, 1992.[8] The PUCT's Energy Efficiency Rule was first adopted in 1999. The gap between these dates makes it plausible that the development of the RFP the growth in importance that the PUCT has placed on energy efficiency goals of the electric utilities was not foreseen. Just because the RFP does not explicitly include energy efficiency adjustments does not mean that they are not adjustments for the Commission to consider.

Q. MR. NARVAEZ SUGGESTS THAT ENERGY EFFICIENCY PROGRAMS DO NOT RESULT IN LOWER ENERGY USAGE OVERALL. WHAT DO YOU RESPOND?

A. EPE has for many years filed the required EEPR and during those proceedings, has received Commission-approved performance bonuses because of the energy savings documented in each of the EEPRs. It is troubling to read Mr. Narvaez's testimony in which he negates that energy efficiency programs result in lower energy usage. If the Commission felt the same way that Mr. Narvaez feels about Commission-approved energy efficiency programs not resulting in any savings, I think those performance bonus incentives would have been discontinued a long time ago.[9]

Q. DOES TEST YEAR DATA ALREADY INCLUDE THE FULL IMPACT OF THE ENERGY EFFICIENCY PROGRAMS?

A. No. Unadjusted test year data includes the energy savings associated with energy efficiency programs only beginning with the month that the program participants

[8] The Rate Filing Package for Investor-Owned Generating Utilities is available at: http://www.puc.texas.gov/industry/electric/forms/rfp/1992_VI_IOU.pdf

[9] In its most recent filing pursuant to the EE Rule, EPE filed for the recovery of a $3.6 million performance bonus for the 2020 program year.

completed the energy efficiency measures. Participation and completion of these measures occurred throughout the test year. As such, the energy savings associated with these measures were not seen in the test year months prior to the completion of the measures. Therefore, an annualization adjustment to each month is needed to ensure that test year data reflects twelve months at full participation levels. For example, the test year data needs to reflect twelve months of energy savings for that customer that completed the energy efficiency measures during the last month of the test year.

Q. WHAT IS YOUR CONCLUSION WITH REGARD TO MR. NARVAEZ'S PROPOSAL IN THIS MATTER?

A. The energy efficiency annualization adjustment is based on "known and measurable" (*i.e.*, PUCT-appointed EM&V contractor verified) values documented in EPE's filed 2021 EEPR. Additionally, the similarity between the customer year-end annualization and the energy efficiency annualization makes them conjunctively subject to acceptance or rejection.

As previously mentioned, the energy efficiency adjustment is based on EM&V verified energy savings using the rate-making principle of annualization. Therefore, the proposal to reject the energy efficiency annualization adjustment by Mr. Narvaez should be rejected. If not, then EPE's proposed customer year-end annualization adjustment should be rejected as well, since that adjustment also uses the rate-making principle of "annualization."

Q. DID ANY OF THE COMMISSION STAFF WITNESSES PROPOSE A REVENUE INCREASE DISTRIBUTION?

A. No, none of them proposed a revenue increase distribution in direct testimony. A revenue increase distribution, however, was included in a workpaper to Staff's rate design, but at a reduced proposed revenue increase. Please see Exhibit MC-2R for a comparison of Staff's proposal against the other proposed distributions in this proceeding. Nevertheless, at Staff's reduced increase, it is difficult to make a good comparison.

Q. MR. NARVAEZ MAKES THE RECOMMENDATION THAT EPE'S PROPOSAL TO UPDATE ITS FTRF TARIFF WITHIN SIX MONTHS, AT A MINIMUM, IN THE CASE OF CHANGE IN THE FEDERAL CORPORATE INCOME TAX BE REJECTED. WHAT IS YOUR RESPONSE?

A. Full-blown rate proceedings are very expensive, and it is for that reason that EPE has proposed to file to update only the FTRF rider schedule in the event of a tax rate change, whether on its own behalf or in response to a Commission order. As with any other filing, Staff and other parties will have the opportunity to file their concerns in such filing, as they did in the existing FTRF. That process worked well in the past and should work well in the future in the event of a tax increase.

XIII. Other Updates

Q. PLEASE DESCRIBE THE ADJUSTMENTS THAT REQUIRED AN ALLOCATION FACTOR UPDATE.

A. Two adjustments are made that impact the allocation factors used in the rebuttal cost-of-service study. The first is related to an error that was discovered in responding to a request from Commission Staff, STAFF 14-1. The second is related to the billing determinants error for Rate 31 that the DOD/FEA witness Larry Blank identified in his testimony and which I concurred to in this testimony. EPE witness Novela incorporated these adjustments into the allocation factor calculations and provided the updated allocation factors to EPE witness Hernandez for use in the rebuttal cost-of-service studies.

Q. HOW DID THESE TWO ADJUSTMENTS IMPACT THE TEXAS REVENUE REQUIREMENT?

A. The impact of these two adjustments resulted in a reduction of $681,774 in the Texas 'as filed' revenue requirement.

Q. HAVE YOU MADE ANY OTHER ADJUSTMENTS OR CORRECTIONS THAT IMPACT THE COST OF SERVICE STUDIES?

A. Yes. Another adjustment I made was to increase the Rate 25 base revenues at present rates for the amount related to the Schedule No. 49 University Discount. For cost-of-service

purposes, the amount related to University Discount is always added back to base revenues but was inadvertently not done so in the original filed documents in this proceeding.

Q. HOW DID THE ADDITION OF AMOUNTS RELATED TO THE UNIVERSITY DISCOUNT IMPACT THE TEXAS REVENUE REQUIREMENT?

A. The addition of the amount related to the University Discount to the Rate 25 base revenues resulted in a revenue increase of $497,369 in the Texas jurisdiction base revenue, thus reducing the revenue requirement that needs to be recovered through proposed rates.

Q. HAVE YOU UPDATED THE REVENUE DISTRIBUTION BASED ON THE UPDATED REBUTTAL COST OF SERVICE STUDY PREPARED BY EPE WITNESS HERNANDEZ?

A. Yes. As shown in Schedule A-1, EPE's updated total operating revenue deficiency is $34.973 million. This equates to a proposed total base rate revenue increase, including non-firm revenues, of $35.694 million or a system average increase of 6.63%[10] and a proposed $721 thousand reduction in miscellaneous charges.

As originally proposed by EPE, an initial limit or "cap" of the indicated base revenue increase for certain rate classes to a maximum of one and a half (1.5) times the non-fuel base revenue increase for all retail rates and a floor for certain other rate classes that EPE's class cost of service indicated base rate revenue decreases. This same approach is proposed for the updated rebuttal revenue requirement, however, 1.5 times the non-fuel base revenue increase for all retail rates to use as a cap is now 9.94%.[11] Exhibit MC-4R shows the derivation of the updated proposed class base revenue allocation, including the caps or floors.

Q. WHAT IS EPE'S UPDATED PROPOSED BASE REVENUE INCREASE BY RATE CLASS?

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[10] EPE is proposing a non-firm base rate revenue increase at the system average or $265 thousand. The base rate revenue increase from the rate classes, net of the non-firm base rate revenue increase, is $35.428 million.

[11] ($35.694 million total base rate increase − $0.265 million for non-firm base rate revenue increase) / $534.574 million in base rate revenue at present rates = 6.63% × 1.5 = 9.94%.

A. Table MC-1 below summarizes both the updated base revenue allocation by class at full cost of service, and after the proposed "capping and flooring" process discussed above.

Table MC- 1

Rate	Rate Class	Base Rate Revenue @ Present Rates	Full Cost of Service *	Full Cost % Revenue Increase	Capped/Floor Cost of Service	Cap/Floor Revenue Increase %	Capped/Floored Revenue Increase $
01	Residential Servcie	$ 273,638,830	$ 325,178,896	18.84%	$ 309,143,611	12.98%	$ 35,504,781
02	Small General Service	33,319,685	29,782,815	-10.61%	32,421,957	-2.69%	(897,728)
07	Outdoor Recreational Lighting	462,980	608,418	31.41%	625,208	35.04%	162,228
08	Government Street Lighting	4,046,620	3,034,952	-25.00%	3,118,707	-22.93%	(927,913)
09	Traffic Signals	95,204	97,262	2.16%	99,946	4.98%	4,742
11TOU	Municipal Pumping TOU	10,102,350	10,057,817	-0.44%	10,335,379	2.31%	233,029
15	Electrolytic Refining Service	1,830,063	2,208,657	20.69%	2,269,609	24.02%	439,546
WH	Water Heating Service	474,582	797,797	68.11%	536,159	12.98%	61,577
22	Irrigation Service	423,413	552,040	30.38%	567,274	33.98%	143,861
24	General Service	125,005,740	112,659,778	-9.88%	122,112,140	-2.31%	(2,893,600)
25	Large Power Service	36,453,034	36,773,064	0.88%	37,787,875	3.66%	1,334,841
26	Petroleum Refinery Service	10,964,770	12,768,972	16.45%	13,121,353	19.67%	2,156,583
28	Area Lighting Service	2,932,614	2,617,908	-10.73%	2,690,153	-8.27%	(242,461)
30	Electric Furnace Rate	1,191,760	1,486,920	24.77%	1,527,954	28.21%	336,194
31	Military Reservation Service	14,373,004	14,803,474	2.99%	15,211,999	5.84%	838,995
34	Cotton Gin Service	132,972	175,881	32.27%	180,735	35.92%	47,763
41	City and County Service	19,126,500	16,397,664	-14.27%	18,252,255	-4.57%	(874,245)
Total		$ 534,574,121	$ 570,002,316	6.63%	$ 570,002,316	6.63%	$ 35,428,195

* Net of $265,342 increase to Non-Firm Revenue.

The revenue increase indicated above does not reflect amounts to be recovered through rate riders that have been proposed by intervenors for rate case expenses, refund of excess ADIT, and amortization of COVID-19 costs.

Q. HAVE YOU UPDATED THE RATE DESIGN BASED ON THE UPDATED REVENUE DISTRIBUTION?

A. No. The rate design will be updated during the final phase of the rate case filing.

Q. HAS EPE UPDATED THE COVID-19 RIDER RATES FOR THE AMORTIZATION REVISIONS DISCUSSED IN THE REBUTTAL TESTIMONY OF EPE WITNESS PRIETO?

A. Yes. As discussed in Ms. Prieto's rebuttal testimony, the Company has agreed to move all COVID-19 costs to the rider and to amortize those costs over five years. The rebuttal cost-of-service studies now exclude all regulatory asset and amortization amounts related to the COVID-19 costs.

Exhibit MC-4R provides the jurisdictional and rate class allocation of the one-year amortization of these costs shown in Ms. Prieto's Exhibit CSP-7R. To determine the Texas jurisdiction amount, a composite jurisdictional allocator, as suggested by DOD/FEA witness Saucedo in page 34 of his direct testimony, was derived using the allocated costs related to the COVID-19 pandemic from each FERC account that were removed for the purpose of this rebuttal. That composite allocator was then applied to the revised amortization and carrying costs included in page 3 of Ms. Prieto's Exhibit CSP-7R.

Q. HAS EPE UPDATED THE FTRF UPDATE SCHEDULE FOR THE REVISED EXCESS ADIT DISCUSSED IN THE REBUTTAL TESTIMONY OF MS. PRIETO?

A. In her testimony, Ms. Prieto has agreed to credit the revised excess ADIT amount to the amount owed by ratepayers because of the relate-back period. As a result of this, the federal tax refund factor/monthly rates in Schedule No. FTRF Update are no longer valid.[12]

Q. IS EPE PROPOSING RATE CASE EXPENSE RIDER RATES AS A RESULT OF EPE'S REBUTTAL TESTIMONY IN THIS PROCEEDING?

A. No. In his rebuttal testimony, EPE witness Schichtl agreed to Staff witness Stark's proposal to recover all rate case expenses through a rate rider. The rates for that rider will be established based on the actual rate case expenses recorded through the post-hearings briefs and the expenses recorded for other cited cases.

XIV. Conclusion

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

[12] Schedule No. FTRF was filed as part of the tariff schedules included in RFP Schedule Q-8.8.

Interruptible Non-Compliance Penalties

Year	Amount	Source
2016	$ 224,189	EPE's response to CEP 9-38
2017	$ 236,450	EPE's response to CEP 9-38
2018	$ 217,484	EPE's response to CEP 9-38
2019	$ -	EPE's response to CEP 9-38
2020	$ 1,212,341	Carrasco Direct Testimony
2021	$ -	Based on EPE's response to VS 5-3

Line	Rate	Rate Class	Full Cost % Revenue Increase[1]	EPE[1]	FMI[2]	OPUC[3]	TIEC[4]	UTEP[5]	CEP[6]	RATE41 Group[7]	VS[8]	Walmart[9]	Staff[10]
1	01	Residential Servcie	18.67%	13.59%	20.90%	14.75%	20.70%	15.68%	10.56%	15.16%	11.07%	13.59%	6.68%
2	02	Small General Service	-10.01%	-2.84%	-9.70%	0.00%	-10.09%	-5.00%	0.00%	-5.00%	-10.01%	-2.84%	-4.54%
3	07	Outdoor Recreational Lighting	32.62%	35.63%	29.40%	14.75%	29.40%	30.00%	10.56%	37.51%	11.07%	35.63%	31.57%
4	08	Government Street Lighting	-24.29%	-22.57%	-25.10%	0.00%	-24.77%	-23.85%	0.00%	-21.49%	-24.29%	-22.57%	-22.43%
5	09	Traffic Signals	3.16%	5.50%	-3.40%	3.69%	-4.01%	3.16%	1.40%	6.96%	3.16%	5.50%	-1.81%
6	11TOU	Municipal Pumping TOU	0.55%	2.84%	-4.90%	3.69%	-6.18%	0.55%	1.59%	4.26%	0.55%	2.84%	-4.95%
7	15	Electrolytic Refining Service	21.78%	24.55%	15.30%	14.75%	15.82%	21.78%	0.00%	26.28%	11.07%	24.55%	18.02%
8	WH	Water Heating Service	69.51%	13.59%	43.00%	14.75%	66.06%	30.00%	10.56%	15.16%	11.07%	13.59%	6.10%
9	22	Irrigation Service	31.46%	34.45%	17.20%	14.75%	34.97%	30.00%	10.56%	36.31%	11.07%	34.45%	26.69%
10	24	General Service	-8.97%	-2.31%	-10.20%	0.00%	-10.86%	-4.49%	2.62%	-4.49%	-8.97%	-2.31%	-4.57%
11	25	Large Power Service	3.28%	5.63%	-1.10%	3.69%	-1.95%	3.28%	9.18%	7.09%	3.28%	5.63%	0.21%
12	26	Petroleum Refinery Service	17.57%	20.25%	7.50%	14.75%	5.86%	17.57%	10.56%	21.91%	11.07%	20.25%	9.88%
13	28	Area Lighting Service	-10.10%	-8.06%	-10.90%	0.00%	-10.46%	-9.92%	0.00%	-6.78%	-10.10%	-8.06%	-8.91%
14	30	Electric Furnace Rate	25.94%	28.80%	14.50%	14.75%	23.48%	25.94%	10.56%	30.59%	11.07%	28.80%	30.18%
15	31	Military Reservation Service	13.14%	15.71%	8.90%	13.14%	7.72%	13.14%	10.56%	17.31%	11.07%	15.71%	9.32%
16	34	Cotton Gin Service	33.53%	36.57%	31.90%	14.75%	32.18%	30.00%	10.56%	38.46%	11.07%	36.57%	32.67%
17	41	City and County Service	-11.51%	-3.61%	-11.70%	0.00%	-12.24%	-5.76%	8.98%	-14.61%	-11.51%	-3.61%	-5.33%
18		Total Firm Base Revenues	7.38%	7.38%	7.40%	7.38%	7.06%	7.38%	7.38%	7.38%	7.38%	7.38%	2.20%
19		Proposed Revenue Increase (000's)	$ 39,297	$ 39,297	$ 39,622	n/a	$ 37,599	$ 39,297	$ 39,295	$ 39,297	n/a	$ 39,297	$ 11,768

Sources:

[1] Table MC-8, Direct Testimony of EPE witness Carrasco

[2] Exhibit JP-9, Direct Testimony of FMI witness Pollock

[3] Page 25 Line 12 through Page 26 Line 2, Direct Testimony of OPUC witness Evans

[4] Exhibit KCH-10, Direct Testimony of TIEC witness Higgins

[5] Table KP-9, Direct Testimony of UTEP witness Pevoto

[6] Schedule CJ-5, Direct Testimony of CEP witness Johnson

[7] Table 1, Direct Testimony of RATE41 witness Daniel

[8] Page 12 Lines 11 through 12, Direct Testimony of VS witness Stanley

[9] Page 14 Lines 1 through 6, Direct Testimony of Walmart witness Teague

[10] Staff did not propose a revenue increase distribution in testimony, however, a revenue distribution is included in Staff's Rate Design workpaper

Line	Description	Total Texas	R01-Residential	R02-Small Gen Serv	R07-Rec Light	R08-Street Light	R09-Traffic Signs	R11TOU-Muni Pump	R15-Elec Ref	R22-Irrig Serv	R24-Gen Serv	R25-Large Power	R26-Petroleum Ref	R28-P Area Light	R30-Elec Furnace	R31-Mili Reserv	R34-Cotton Gin	R41-Cty/Cnty	RWH-Water Heating
1	**DEMAND COMPONENTS**																		
2	Dem Production	$272,358,366	$149,865,033	$13,096,987	$77,752	$649,828	$46,054	$4,409,185	$1,448,198	$254,017	$56,425,294	$18,652,003	$7,909,360	$480,644	$1,025,244	$9,658,147	$30,681	$8,187,144	$142,793
3	Dem Transmission	59,951,732	33,765,643	3,090,064	25,292	25,428	8,767	953,477	323,965	54,369	11,862,871	3,893,361	1,786,877	18,996	228,392	2,144,222	5,492	1,711,015	53,502
4	Dem Dist LD	37,481,071	22,736,556	2,016,994	124,237	205,252	4,835	800,387	0	46,376	7,723,662	2,305,547	0	154,532	0	0	35,026	1,220,462	107,205
5	Dem Dist PTF Prim	12,622,031	7,644,513	668,157	42,580	67,146	1,586	273,041	0	16,069	2,622,419	774,192	0	50,524	0	0	12,082	415,701	34,020
6	Dem Dist PTF Sec	7,539,712	5,003,209	410,730	19,162	31,510	767	143,815	0	11,186	1,346,455	325,981	0	23,749	0	0	5,435	191,975	25,738
7	Dem Dist OH Prim	12,089,811	7,322,066	641,472	40,579	64,474	1,530	261,145	0	15,329	2,510,198	742,658	0	48,494	0	0	11,506	397,748	32,611
8	Dem Dist OH Sec	1,576,576	1,045,000	86,069	4,004	6,631	162	30,067	0	2,326	281,896	68,658	0	4,998	0	0	1,134	40,256	5,375
9	Dem Dist UG Prim	21,771,752	13,052,578	1,129,804	78,571	116,988	2,679	484,334	0	28,019	4,604,853	1,364,732	0	87,834	0	0	22,388	739,648	59,324
10	Dem Dist UG Sec	6,696,037	4,501,410	361,064	17,106	26,382	627	127,334	0	10,361	1,170,159	268,019	0	19,836	0	0	4,876	164,532	24,332
11	Dem Dist Tran Prim	11,871,420	6,964,567	587,625	46,969	65,128	1,421	278,952	0	15,813	2,614,211	777,781	0	48,644	0	0	13,536	428,224	28,547
12	Dem Dist Tran Sec	9,606,729	6,527,706	499,124	25,259	35,010	780	186,405	0	16,042	1,666,477	350,608	0	26,154	0	0	7,332	231,658	34,175
13		$453,565,238	$258,428,280	$22,588,091	$501,510	$1,293,778	$69,209	$7,948,141	$1,772,163	$469,907	$92,828,496	$29,523,539	$9,696,238	$964,407	$1,253,636	$11,802,369	$149,487	$13,728,363	$547,623
14																			
15	**ENERGY COMPONENTS**																		
16	Energy Other	$63,542,885	$28,813,836	$3,049,423	$43,849	$374,681	$19,883	$1,658,597	$437,602	$43,639	$14,566,871	$5,891,619	$3,078,804	$278,469	$233,963	$3,008,755	$16,730	$1,957,465	$68,699
17	Fuel	(0)	0	0	0	(0)	(0)	(0)	(0)	0	(0)	(0)	0	0	0	0	0	0	0
18		$63,542,885	$28,813,836	$3,049,423	$43,849	$374,681	$19,883	$1,658,597	$437,602	$43,639	$14,566,871	$5,891,619	$3,078,804	$278,469	$233,963	$3,008,755	$16,730	$1,957,465	$68,699
19																			
20	**CUSTOMER COMPONENTS**																		
21	Cust Other	$1,677,462	$1,408,856	$127,435	$824	$676	$189	$1,480	$4	$846	$115,312	$13,241	$4	$4,621	$4	$4	$156	$3,137	$674
22	Cust Deposits	(597,802)	(500,541)	(45,663)	(418)	(283)	(95)	(2,693)	(58)	(311)	(33,005)	(7,987)	(284)	(1,453)	(120)	(261)	(36)	(4,440)	(153)
23	Cust 369-Servs	3,530,210	2,775,308	258,168	7,919	0	516	25,856	0	1,977	352,103	50,394	0	7,183	0	0	479	45,207	5,099
24	Cust 370-Ms	12,992,107	9,243,676	929,375	21,704	0	1,681	166,536	173	12,112	1,772,514	492,442	1,007	408	200	1,231	4,739	244,154	100,154
25	Cust 371-Install	1,296,887	0	0	0	0	0	0	0	0	0	0	0	1,296,887	0	0	0	0	0
26	Cust 373-Str Light	1,348,246	0	0	0	1,348,246	0	0	0	0	0	0	0	0	0	0	0	0	0
27	Cust 902-M Read	4,398,752	3,298,305	363,749	4,676	0	490	40,160	55	3,491	464,587	123,754	310	0	57	374	672	64,001	34,070
28	Cust 903-C R C	28,513,674	21,858,564	2,524,780	28,353	17,855	5,423	223,946	85	20,634	2,648,662	704,192	202	67,385	85	228	3,658	367,922	41,698
29		$53,159,535	$38,084,168	$4,157,844	$63,059	$1,366,493	$8,205	$455,286	$259	$38,750	$5,320,173	$1,376,037	$1,239	$1,375,032	$226	$1,575	$9,668	$719,981	$181,542
30																			
31	TOTAL DEC TOTAL DEMAND AND	$570,267,658	$325,326,284	$29,795,359	$608,418	$3,034,952	$97,296	$10,062,023	$2,210,024	$552,296	$112,715,540	$36,791,195	$12,776,281	$2,617,908	$1,487,826	$14,812,699	$175,884	$16,405,809	$797,864
32	ENERGY COMPONENTS	$517,108,123	$287,242,116	$25,637,515	$545,359	$1,668,459	$89,092	$9,606,737	$2,209,765	$513,546	$107,395,367	$35,415,158	$12,775,042	$1,242,876	$1,487,600	$14,811,124	$166,216	$15,685,828	$616,322
33																			
34	kWh	5,934,580,280	2,478,851,326	272,309,109	3,676,526	36,054,763	2,655,162	172,350,354	42,604,774	3,840,029	1,450,801,644	611,107,048	314,641,719	26,829,319	21,568,632	297,329,301	1,596,380	193,240,554	5,123,640
35	kW	7,885,711	0	0	0	0	0	0	90,000	0	4,599,057	1,412,387	484,800	0	62,983	612,000	5,904	618,580	0
36	Customer	4,065,180	3,615,636	328,728	2,532	2,148	600	4,824	12	1,728	87,516	1,320	12	9,852	12	12	24	10,152	72

EXHIBIT MC-3R
PAGE 1 OF 6

Line	Description	Total Texas	R01-Residential	R02-Small Gen Serv	R07-Rec Light	R08-Street Light	R09-Traffic Signs	R11TOU-Muni Pump	R15-Elec Ref	R22-Irrig Serv	R24-Gen Serv	R25-Large Power	R26-Petroleum Ref	R28-P Area Light	R30-Elec Furnace	R31-Mili Reserv	R34-Cotton Gin	R41-Cty/Cnty	RWH-Water Heating
1	**DEMAND COMPONENTS ($/kWh)**																		
2	Dem Production	$0.045893	$0.060457	$0.048096	$0.021148	$0.018023	$0.017345	$0.025583	$0.033991	$0.066150	$0.038892	$0.030522	$0.025138	$0.017915	$0.047534	$0.032483	$0.019219	$0.042368	$0.027869
3	Dem Transmission	0.010102	0.013621	0.011348	0.006879	0.000705	0.003302	0.005532	0.007604	0.014158	0.008177	0.006371	0.005679	0.000708	0.010589	0.007212	0.003440	0.008854	0.010442
4	Dem Dist LD	0.006316	0.009172	0.007407	0.033792	0.005693	0.001821	0.004644	0.000000	0.012077	0.005324	0.003773	0.000000	0.005760	0.000000	0.000000	0.021941	0.006316	0.020924
5	Dem Dist PTF Prim	0.002127	0.003084	0.002454	0.011582	0.001862	0.000597	0.001584	0.000000	0.004185	0.001808	0.001267	0.000000	0.001883	0.000000	0.000000	0.007568	0.002151	0.006640
6	Dem Dist PTF Sec	0.001270	0.002018	0.001508	0.005212	0.000874	0.000289	0.000834	0.000000	0.002913	0.000928	0.000533	0.000000	0.000885	0.000000	0.000000	0.003404	0.000993	0.005023
7	Dem Dist OH Prim	0.002037	0.002954	0.002356	0.011037	0.001788	0.000576	0.001515	0.000000	0.003992	0.001730	0.001215	0.000000	0.001808	0.000000	0.000000	0.007207	0.002058	0.006365
8	Dem Dist OH Sec	0.000266	0.000422	0.000316	0.001089	0.000184	0.000061	0.000174	0.000000	0.000606	0.000194	0.000112	0.000000	0.000186	0.000000	0.000000	0.000711	0.000208	0.001049
9	Dem Dist UG Prim	0.003669	0.005266	0.004149	0.021371	0.003245	0.001009	0.002810	0.000000	0.007297	0.003174	0.002233	0.000000	0.003274	0.000000	0.000000	0.014024	0.003828	0.011579
10	Dem Dist UG Sec	0.001128	0.001816	0.001326	0.004653	0.000732	0.000236	0.000739	0.000000	0.002698	0.000807	0.000439	0.000000	0.000739	0.000000	0.000000	0.003054	0.000851	0.004749
11	Dem Dist Tran Prim	0.002000	0.002810	0.002158	0.012775	0.001806	0.000535	0.001619	0.000000	0.004118	0.001802	0.001273	0.000000	0.001813	0.000000	0.000000	0.008479	0.002216	0.005572
12	Dem Dist Tran Sec	0.001619	0.002633	0.001833	0.006870	0.000971	0.000294	0.001082	0.000000	0.004178	0.001149	0.000574	0.000000	0.000975	0.000000	0.000000	0.004593	0.001199	0.006670
13		$0.076428	$0.104253	$0.082950	$0.136409	$0.035884	$0.026066	$0.046116	$0.041595	$0.122371	$0.063984	$0.048312	$0.030817	$0.035946	$0.058123	$0.039695	$0.093641	$0.071043	$0.106882
14																			
15	**DEMAND COMPONENTS ($/kW)**																		
16	Dem Production	$34.538	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$16.091	$0.000	$12.269	$13.206	$16.315	$0.000	$16.278	$15.781	$5.197	$13.235	$0.000
17	Dem Transmission	7.603	0.000	0.000	0.000	0.000	0.000	0.000	3.600	0.000	2.579	2.757	3.686	0.000	3.626	3.504	0.930	2.766	0.000
18	Dem Dist LD	4.753	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	1.679	1.632	0.000	0.000	0.000	0.000	5.933	1.973	0.000
19	Dem Dist PTF Prim	1.601	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.570	0.548	0.000	0.000	0.000	0.000	2.046	0.672	0.000
20	Dem Dist PTF Sec	0.956	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.293	0.231	0.000	0.000	0.000	0.000	0.920	0.310	0.000
21	Dem Dist OH Prim	1.533	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.546	0.526	0.000	0.000	0.000	0.000	1.949	0.643	0.000
22	Dem Dist OH Sec	0.200	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.061	0.049	0.000	0.000	0.000	0.000	0.192	0.065	0.000
23	Dem Dist UG Prim	2.761	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	1.001	0.966	0.000	0.000	0.000	0.000	3.792	1.196	0.000
24	Dem Dist UG Sec	0.849	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.254	0.190	0.000	0.000	0.000	0.000	0.826	0.266	0.000
25	Dem Dist Tran Prim	1.505	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.568	0.551	0.000	0.000	0.000	0.000	2.293	0.692	0.000
26	Dem Dist Tran Sec	1.218	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.362	0.248	0.000	0.000	0.000	0.000	1.242	0.374	0.000
27		$57.517	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$19.691	$0.000	$20.184	$20.903	$20.000	$0.000	$19.904	$19.285	$25.320	$22.193	$0.000
28																			
29	**ENERGY COMPONENTS ($/kWh)**																		
30	Energy Other	$0.0107072	$0.0116239	$0.0111984	$0.0119268	$0.0103920	$0.0074885	$0.0096234	$0.0102712	$0.0113643	$0.0100406	$0.0096409	$0.0097851	$0.0103793	$0.0108474	$0.0101193	$0.0104797	$0.0101297	$0.0134082
31	Fuel	(0.0000000)	0.0000000	0.0000000	0.0000000	(0.0000000)	(0.0000000)	(0.0000000)	(0.0000000)	0.0000000	(0.0000000)	(0.0000000)	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
32		$0.0107072	$0.0116239	$0.0111984	$0.0119268	$0.0103920	$0.0074885	$0.0096234	$0.0102712	$0.0113643	$0.0100406	$0.0096409	$0.0097851	$0.0103793	$0.0108474	$0.0101193	$0.0104797	$0.0101297	$0.0134082
33																			
34	**CUSTOMER COMPONENTS ($/ANNUAL CUSTOMERS)**																		
35	Cust Other	$0.413	$0.390	$0.388	$0.326	$0.315	$0.314	$0.307	$0.315	$0.490	$1.318	$10.031	$0.314	$0.469	$0.315	$0.314	$6.500	$0.309	$9.361
36	Cust Deposits	(0.147)	(0.138)	(0.139)	(0.165)	(0.132)	(0.158)	(0.558)	(4.857)	(0.180)	(0.377)	(6.051)	(23.665)	(0.148)	(9.959)	(21.781)	(1.498)	(0.437)	(2.124)
37	Cust 369-Servs	0.868	0.768	0.785	3.128	0.000	0.860	5.360	0.000	1.144	4.023	38.178	0.000	0.729	0.000	0.000	19.965	4.453	70.814
38	Cust 370-Ms	3.196	2.557	2.827	8.572	0.000	2.801	34.522	14.389	7.009	20.254	373.062	83.903	0.041	16.680	102.568	197.462	24.050	1,391.029
39	Cust 371-Install	0.319	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	131.637	0.000	0.000	0.000	0.000	0.000
40	Cust 373-Str Light	0.332	0.000	0.000	0.000	627.675	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
41	Cust 902-M Read	1.082	0.912	1.107	1.847	0.000	0.817	8.325	4.612	2.020	5.309	93.753	25.862	0.000	4.727	31.153	28.013	6.304	473.196
42	Cust 903-C R C	7.014	6.046	7.680	11.198	9.312	9.039	46.423	7.094	11.941	30.265	533.479	16.817	6.840	7.078	19.011	152.403	36.241	579.143
43		$13.077	$10.533	$12.648	$24.905	$636.170	$13.674	$94.379	$21.553	$22.425	$60.791	$1,042.452	$103.231	$139.569	$18.841	$131.264	$402.844	$70.920	$2,521.419

EXHIBIT MC-3R
PAGE 2 OF 6

Line	Description	Total Texas	R01-Residential	R02-Small Gen Serv	R07-Rec Light	R08-Street Light	R09-Traffic Signs	R11TOU-Muni Pump	R15-Elec Ref	R22-Irrig Serv	R24-Gen Serv	R25-Large Power	R26-Petroleum Ref	R28-P Area Light	R30-Elec Furnace	R31-Milli Reserv	R34-Cotton Gin	R41-Cty/Cnty	RWH-Water Heating
1	DEC COMPONENTS																		
2	PRODUCTION	$272,358,366	$149,865,033	$13,096,987	$77,752	$649,828	$46,054	$4,409,185	$1,448,198	$254,017	$56,425,294	$18,652,003	$7,909,360	$480,644	$1,025,244	$9,658,147	$30,681	$8,187,144	$142,793
3	TRANSMISSION	59,951,732	33,765,643	3,090,064	25,292	25,428	8,767	953,477	323,965	54,369	11,862,871	3,893,361	1,786,877	18,996	228,392	2,144,222	5,492	1,711,015	53,502
4	DISTRIBUTION	121,255,139	74,797,605	6,401,040	398,466	618,522	14,387	2,585,479	0	161,521	24,540,331	6,978,176	0	464,767	0	0	113,314	3,830,204	351,328
5	TOTAL DEMAND	$453,565,238	$258,428,280	$22,588,091	$501,510	$1,293,778	$69,209	$7,948,141	$1,772,163	$469,907	$92,828,496	$29,523,539	$9,696,238	$964,407	$1,253,636	$11,802,369	$149,487	$13,728,363	$547,623
6	TOTAL ENERGY	63,542,885	28,813,836	3,049,423	43,849	374,681	19,883	1,658,597	437,602	43,639	14,566,871	5,891,619	3,078,804	278,469	233,963	3,008,755	16,730	1,957,465	68,699
7	TOTAL CUSTOMER	53,159,535	38,084,168	4,157,844	63,059	1,366,493	8,205	455,286	259	38,750	5,320,173	1,376,037	1,239	1,375,032	226	1,575	9,668	719,981	181,542
8	TOTAL DEC COMPONENTS	$570,267,658	$325,326,284	$29,795,359	$608,418	$3,034,952	$97,296	$10,062,023	$2,210,024	$552,296	$112,715,540	$36,791,195	$12,776,281	$2,617,908	$1,487,826	$14,812,699	$175,884	$16,405,809	$797,864
9	COVID19 RIDER REVENUE[1]	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
10	NON-FIRM REVENUE[2] INCREASE @ SYSTEM AVERAGE	265,342	147,388	12,544	0	0	34	4,206	1,367	256	55,762	18,131	7,308	0	906	9,226	3	8,145	67
11	NET TOTAL DEC COMPONENTS	$570,002,316	$325,178,896	$29,782,815	$608,418	$3,034,952	$97,262	$10,057,817	$2,208,657	$552,040	$112,659,778	$36,773,064	$12,768,972	$2,617,908	$1,486,920	$14,803,474	$175,881	$16,397,664	$797,797
12	BASE RATE REVENUE AT PRESENT RATES	$534,574,121	$273,638,830	$33,319,685	$462,980	$4,046,620	$95,204	$10,102,350	$1,830,063	$423,413	$125,005,740	$36,453,034	$10,964,770	$2,932,614	$1,191,760	$14,373,004	$132,972	$19,126,500	$474,582
13	**% NON-FUEL INCREASE AT NET FULL COST**	**6.63%**	**18.84%**	**-10.61%**	**31.41%**	**-25.00%**	**2.16%**	**-0.44%**	**20.69%**	**30.38%**	**-9.88%**	**0.88%**	**16.45%**	**-10.73%**	**24.77%**	**2.99%**	**32.27%**	**-14.27%**	**68.11%**
14	Capping Level[3]		2	1	0	0	0	0	0	0	1	0	0	0	0	0	0	1	2
15	CAPPED INCREASE / FLOOR DECREASE		9.94%	-5.31%	31.41%	-25.00%	2.16%	-0.44%	20.69%	30.38%	-4.94%	0.88%	16.45%	-10.73%	24.77%	2.99%	32.27%	-7.13%	9.94%
16	REV. REQ. AT CAPPED INCREASE / FLOOR DECREASE	$ 554,694,627	$ 300,841,409	$ 31,551,250	$ 608,418	$ 3,034,952	$ 97,262	$ 10,057,817	$ 2,208,657	$ 552,040	$ 118,832,759	$ 36,773,064	$ 12,768,972	$ 2,617,908	$ 1,486,920	$ 14,803,474	$ 175,881	$ 17,762,082	$ 521,760
17	REV. REQ. DEFICIENCY	$ 15,307,689																	
18	REV. REQ. SUBJECT TO DEFICIENCY ALLOCATION	$ 554,694,627	$ 300,841,409	$ 31,551,250	$ 608,418	$ 3,034,952	$ 97,262	$ 10,057,817	$ 2,208,657	$ 552,040	$ 118,832,759	$ 36,773,064	$ 12,768,972	$ 2,617,908	$ 1,486,920	$ 14,803,474	$ 175,881	$ 17,762,082	$ 521,760
19	ALLOCATION OF DEFICIENCY	$ 15,307,689	$ 8,302,202	$ 870,707	$ 16,790	$ 83,754	$ 2,684	$ 277,562	$ 60,951	$ 15,234	$ 3,279,381	$ 1,014,812	$ 352,380	$ 72,245	$ 41,034	$ 408,526	$ 4,854	$ 490,173	$ 14,399
20	REV. REQ. WITH DEFICIENCY ALLOCATION	$ 570,002,316	$ 309,143,611	$ 32,421,957	$ 625,208	$ 3,118,707	$ 99,946	$ 10,335,379	$ 2,269,609	$ 567,274	$ 122,112,140	$ 37,787,875	$ 13,121,353	$ 2,690,153	$ 1,527,954	$ 15,211,999	$ 180,735	$ 18,252,255	$ 536,159
21	**% NON-FUEL INCREASE W/ CAP OR FLOOR**	**6.63%**	**12.98%**	**-2.69%**	**35.04%**	**-22.93%**	**4.98%**	**2.31%**	**24.02%**	**33.98%**	**-2.31%**	**3.66%**	**19.67%**	**-8.27%**	**28.21%**	**5.84%**	**35.92%**	**-4.57%**	**12.98%**
22	BASE REVENUE INCREASE	$ 35,428,195	$ 35,504,781	$ (897,728)	$ 162,228	$ (927,913)	$ 4,742	$ 233,029	$ 439,546	$ 143,861	$ (2,893,600)	$ 1,334,841	$ 2,156,583	$ (242,461)	$ 336,194	$ 838,995	$ 47,763	$ (874,245)	$ 61,577
23	COVID19 RIDER REVENUE	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
24	NON-FIRM REVENUE INCREASE	265,342	147,388	12,544	0	0	34	4,206	1,367	256	55,762	18,131	7,308	0	906	9,226	3	8,145	67
25	BASE & NON-FIRM REVENUE INCREASE	$ 35,693,537	$ 35,652,169	$ (885,184)	$ 162,228	$ (927,913)	$ 4,777	$ 237,235	$ 440,912	$ 144,117	$ (2,837,838)	$ 1,352,972	$ 2,163,891	$ (242,461)	$ 337,100	$ 848,221	$ 47,766	$ (866,100)	$ 61,645

[1] COVID19 EXPENSES TO BE RECOVERED VIA A STANDALONE RIDER TARIFF. THE AMORTIZATION HAS BEEN REMOVED FROM THE REBUTTAL REVENUE REQUIREMENT.

26	[2] NON-FIRM BASE REVENUE AT PRESENT RATES	$ 4,003,726	$ 2,223,928	$ 189,272	$ -	$ -	$ 517	$ 63,460	$ 20,621	$ 3,859	$ 841,384	$ 273,580	$ 110,272	$ -	$ 13,665	$ 139,206	$ 45	$ 122,903	$ 1,015

27 [3] Capping Level:
0 - No Cap / No Floor
1 - 50% Floor
2 - 1.5 x System Average
3 - 2.0 x System Average

Line	Description	Total Texas	R01-Residential	R02-Small Gen Serv	R07-Rec Light	R08-Street Light	R09-Traffic Signs	R11TOU-Muni Pump	R15-Elec Ref	R22-Irrig Serv	R24-Gen Serv	R25-Large Power	R26-Petroleum Ref	R28-P Area Light	R30-Elec Furnace	R31-Mili Reserv	R34-Cotton Gin	R41-Cty/Cnty	RWH-Water Heating
1	**DEMAND COMPONENTS**																		
2	Dem Production	$272,360,860	$141,421,923	$14,438,792	$80,145	$682,449	$47,424	$4,534,646	$1,487,248	$261,426	$61,362,247	$19,176,922	$8,123,003	$508,583	$1,052,900	$9,918,526	$31,576	$9,150,888	$82,160
3	Dem Transmission	59,845,498	31,863,351	3,406,646	26,071	26,705	9,028	980,607	332,700	55,955	12,900,818	4,002,931	1,835,144	20,100	234,553	2,202,029	5,653	1,912,426	30,784
4	Dem Dist LD	37,293,998	21,455,622	2,223,638	128,062	215,556	4,978	823,161	0	47,729	8,399,447	2,370,431	0	163,514	0	0	36,048	1,364,128	61,683
5	Dem Dist PTF Prim	12,561,790	7,213,836	736,611	43,891	70,517	1,633	280,811	0	16,538	2,851,868	795,980	0	53,461	0	0	12,434	464,635	19,574
6	Dem Dist PTF Sec	7,446,724	4,721,338	452,810	19,752	33,092	790	147,907	0	11,512	1,464,263	335,155	0	25,130	0	0	5,593	214,573	14,809
7	Dem Dist OH Prim	12,032,087	6,909,555	707,192	41,828	67,710	1,575	268,576	0	15,776	2,729,829	763,559	0	51,313	0	0	11,842	444,569	18,764
8	Dem Dist OH Sec	1,557,281	986,127	94,886	4,127	6,964	167	30,923	0	2,394	306,561	70,590	0	5,289	0	0	1,167	44,994	3,093
9	Dem Dist UG Prim	21,684,062	12,317,220	1,245,554	80,990	122,861	2,758	498,115	0	28,837	5,007,756	1,403,139	0	92,940	0	0	23,041	826,716	34,134
10	Dem Dist UG Sec	6,605,480	4,247,809	398,056	17,632	27,706	646	130,957	0	10,663	1,272,543	275,562	0	20,989	0	0	5,018	183,900	14,000
11	Dem Dist Tran Prim	11,844,538	6,572,197	647,828	48,415	68,397	1,464	286,890	0	16,274	2,842,943	799,670	0	51,472	0	0	13,931	478,632	16,425
12	Dem Dist Tran Sec	9,468,606	6,159,947	550,260	26,037	36,767	803	191,709	0	16,510	1,812,286	360,475	0	27,674	0	0	7,546	258,927	19,663
13		$452,700,924	$243,868,924	$24,902,273	$516,950	$1,358,724	$71,267	$8,174,302	$1,819,948	$483,612	$100,950,562	$30,354,414	$9,958,147	$1,020,466	$1,287,453	$12,120,555	$153,849	$15,344,388	$315,090
14																			
15	**ENERGY COMPONENTS**																		
16	Energy Other	$64,141,857	$27,190,520	$3,361,841	$45,199	$393,490	$20,475	$1,705,791	$449,402	$44,912	$15,841,405	$6,057,425	$3,161,967	$294,655	$240,275	$3,089,870	$17,218	$2,187,886	$39,528
17	Fuel	(0)	0	0	0	(0)	(0)	(0)	(0)	0	(0)	(0)	0	0	0	0	0	0	0
18		$64,141,857	$27,190,520	$3,361,841	$45,199	$393,490	$20,475	$1,705,791	$449,402	$44,912	$15,841,405	$6,057,425	$3,161,967	$294,655	$240,275	$3,089,870	$17,218	$2,187,886	$39,528
19																			
20	**CUSTOMER COMPONENTS**																		
21	Cust Other	$1,677,462	$1,408,856	$127,435	$824	$676	$189	$1,480	$4	$846	$115,312	$13,241	$4	$4,621	$4	$4	$156	$3,137	$674
22	Cust Deposits	(597,802)	(500,541)	(45,663)	(418)	(283)	(95)	(2,693)	(58)	(311)	(33,005)	(7,987)	(284)	(1,453)	(120)	(261)	(36)	(4,440)	(153)
23	Cust 369-Servs	3,530,210	2,775,308	258,168	7,919	0	516	25,856	0	1,977	352,103	50,394	0	7,183	0	0	479	45,207	5,099
24	Cust 370-Ms	12,992,107	9,243,676	929,375	21,704	0	1,681	166,536	173	12,112	1,772,514	492,442	1,007	408	200	1,231	4,739	244,154	100,154
25	Cust 371-Install	1,296,887	0	0	0	0	0	0	0	0	0	0	0	1,296,887	0	0	0	0	0
26	Cust 373-Str Light	1,348,246	0	0	0	1,348,246	0	0	0	0	0	0	0	0	0	0	0	0	0
27	Cust 902-M Read	4,398,752	3,298,305	363,749	4,676	0	490	40,160	55	3,491	464,587	123,754	310	0	57	374	672	64,001	34,070
28	Cust 903-C R C	28,513,674	21,858,564	2,524,780	28,353	17,855	5,423	223,946	85	20,634	2,648,662	704,192	202	67,385	85	228	3,658	367,922	41,698
29		$53,159,535	$38,084,168	$4,157,844	$63,059	$1,366,493	$8,205	$455,286	$259	$38,750	$5,320,173	$1,376,037	$1,239	$1,375,032	$226	$1,575	$9,668	$719,981	$181,542
30																			
31	TOTAL DEC	$570,002,316	$309,143,611	$32,421,957	$625,208	$3,118,707	$99,946	$10,335,379	$2,269,609	$567,274	$122,112,140	$37,787,875	$13,121,353	$2,690,153	$1,527,954	$15,211,999	$180,735	$18,252,255	$536,159
32																			
33																			
34	kWh	5,934,580,280	2,478,851,326	272,309,109	3,676,526	36,054,763	2,655,162	172,350,354	42,604,774	3,840,029	1,450,801,644	611,107,048	314,641,719	26,829,319	21,568,632	297,329,301	1,596,380	193,240,554	5,123,640
35	kW	7,885,711	0	0	0	0	0	0	90,000	0	4,599,057	1,412,387	484,800	0	62,983	612,000	5,904	618,580	0
36	Customer	4,065,180	3,615,636	328,728	2,532	2,148	600	4,824	12	1,728	87,516	1,320	12	9,852	12	12	24	10,152	72

Line	Description	Total Texas	R01-Residential	R02-Small Gen Serv	R07-Rec Light	R08-Street Light	R09-Traffic Signs	R11TOU-Muni Pump	R15-Elec Ref	R22-Irrig Serv	R24-Gen Serv	R25-Large Power	R26-Petroleum Ref	R28-P Area Light	R30-Elec Furnace	R31-Mill Reserv	R34-Cotton Gin	R41-Cty/Cnty	RWH-Water Heating
1	**DEMAND COMPONENTS ($/kWh)**																		
2	Dem Production	$0.045894	$0.057051	$0.053024	$0.021799	$0.018928	$0.017861	$0.026311	$0.034908	$0.068079	$0.042295	$0.031381	$0.025817	$0.018956	$0.048816	$0.033359	$0.019780	$0.047355	$0.016035
3	Dem Transmission	0.010084	0.012854	0.012510	0.007091	0.000741	0.003400	0.005690	0.007809	0.014571	0.008892	0.006550	0.005832	0.000749	0.010875	0.007406	0.003541	0.009897	0.006008
4	Dem Dist LD	0.006284	0.008655	0.008166	0.034832	0.005979	0.001875	0.004776	0.000000	0.012429	0.005790	0.003879	0.000000	0.006095	0.000000	0.000000	0.022581	0.007059	0.012039
5	Dem Dist PTF Prim	0.002117	0.002910	0.002705	0.011938	0.001956	0.000615	0.001629	0.000000	0.004307	0.001966	0.001303	0.000000	0.001993	0.000000	0.000000	0.007789	0.002404	0.003820
6	Dem Dist PTF Sec	0.001255	0.001905	0.001663	0.005372	0.000918	0.000298	0.000858	0.000000	0.002998	0.001009	0.000548	0.000000	0.000937	0.000000	0.000000	0.003504	0.001110	0.002890
7	Dem Dist OH Prim	0.002027	0.002787	0.002597	0.011377	0.001878	0.000593	0.001558	0.000000	0.004108	0.001882	0.001249	0.000000	0.001913	0.000000	0.000000	0.007418	0.002301	0.003662
8	Dem Dist OH Sec	0.000262	0.000398	0.000348	0.001122	0.000193	0.000063	0.000179	0.000000	0.000623	0.000211	0.000116	0.000000	0.000197	0.000000	0.000000	0.000731	0.000233	0.000604
9	Dem Dist UG Prim	0.003654	0.004969	0.004574	0.022029	0.003408	0.001039	0.002890	0.000000	0.007509	0.003452	0.002296	0.000000	0.003464	0.000000	0.000000	0.014433	0.004278	0.006682
10	Dem Dist UG Sec	0.001113	0.001714	0.001462	0.004796	0.000768	0.000243	0.000760	0.000000	0.002777	0.000877	0.000451	0.000000	0.000782	0.000000	0.000000	0.003144	0.000952	0.002732
11	Dem Dist Tran Prim	0.001996	0.002651	0.002379	0.013169	0.001897	0.000551	0.001665	0.000000	0.004238	0.001960	0.001309	0.000000	0.001918	0.000000	0.000000	0.008727	0.002477	0.003206
12	Dem Dist Tran Sec	0.001595	0.002485	0.002021	0.007082	0.001020	0.000303	0.001112	0.000000	0.004299	0.001249	0.000590	0.000000	0.001031	0.000000	0.000000	0.004727	0.001340	0.003838
13		$0.076282	$0.098380	$0.091449	$0.140608	$0.037685	$0.026841	$0.047428	$0.042717	$0.125940	$0.069583	$0.049671	$0.031649	$0.038035	$0.059691	$0.040765	$0.096374	$0.079406	$0.061497
14																			
15	**DEMAND COMPONENTS ($/kW)**																		
16	Dem Production	$34.539	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$16.525	$0.000	$13.342	$13.578	$16.755	$0.000	$16.717	$16.207	$5.348	$14.793	$0.000
17	Dem Transmission	7.589	0.000	0.000	0.000	0.000	0.000	0.000	3.697	0.000	2.805	2.834	3.785	0.000	3.724	3.598	0.957	3.092	0.000
18	Dem Dist LD	4.729	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	1.826	1.678	0.000	0.000	0.000	0.000	6.106	2.205	0.000
19	Dem Dist PTF Prim	1.593	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.620	0.564	0.000	0.000	0.000	0.000	2.106	0.751	0.000
20	Dem Dist PTF Sec	0.944	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.318	0.237	0.000	0.000	0.000	0.000	0.947	0.347	0.000
21	Dem Dist OH Prim	1.526	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.594	0.541	0.000	0.000	0.000	0.000	2.006	0.719	0.000
22	Dem Dist OH Sec	0.197	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.067	0.050	0.000	0.000	0.000	0.000	0.198	0.073	0.000
23	Dem Dist UG Prim	2.750	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	1.089	0.993	0.000	0.000	0.000	0.000	3.903	1.336	0.000
24	Dem Dist UG Sec	0.838	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.277	0.195	0.000	0.000	0.000	0.000	0.850	0.297	0.000
25	Dem Dist Tran Prim	1.502	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.618	0.566	0.000	0.000	0.000	0.000	2.360	0.774	0.000
26	Dem Dist Tran Sec	1.201	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.394	0.255	0.000	0.000	0.000	0.000	1.278	0.419	0.000
27		$57.408	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$20.222	$0.000	$21.950	$21.492	$20.541	$0.000	$20.441	$19.805	$26.058	$24.806	$0.000
28																			
29	**ENERGY COMPONENTS ($/kWh)**																		
30	Energy Other	$0.0108082	$0.0109690	$0.0123457	$0.0122940	$0.0109137	$0.0077112	$0.0098972	$0.0105482	$0.0116958	$0.0109191	$0.0099122	$0.0100494	$0.0109826	$0.0111400	$0.0103921	$0.0107855	$0.0113221	$0.0077147
31	Fuel	(0.0000000)	0.0000000	0.0000000	0.0000000	(0.0000000)	(0.0000000)	(0.0000000)	(0.0000000)	0.0000000	(0.0000000)	(0.0000000)	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000
32		$0.0108082	$0.0109690	$0.0123457	$0.0122940	$0.0109137	$0.0077112	$0.0098972	$0.0105482	$0.0116958	$0.0109191	$0.0099122	$0.0100494	$0.0109826	$0.0111400	$0.0103921	$0.0107855	$0.0113221	$0.0077147
33																			
34	**CUSTOMER COMPONENTS ($/ANNUAL CUSTOMERS)**																		
35	Cust Other	$0.413	$0.390	$0.388	$0.326	$0.315	$0.314	$0.307	$0.315	$0.490	$1.318	$10.031	$0.314	$0.469	$0.315	$0.314	$6.500	$0.309	$9.361
36	Cust Deposits	(0.147)	(0.138)	(0.139)	(0.165)	(0.132)	(0.158)	(0.558)	(4.857)	(0.180)	(0.377)	(6.051)	(23.665)	(0.148)	(9.959)	(21.781)	(1.498)	(0.437)	(2.124)
37	Cust 369-Servs	0.868	0.768	0.785	3.128	0.000	0.860	5.360	0.000	1.144	4.023	38.178	0.000	0.729	0.000	0.000	19.965	4.453	70.814
38	Cust 370-Ms	3.196	2.557	2.827	8.572	0.000	2.801	34.522	14.389	7.009	20.254	373.062	83.903	0.041	16.680	102.568	197.462	24.050	1,391.029
39	Cust 371-Install	0.319	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	131.637	0.000	0.000	0.000	0.000	0.000
40	Cust 373-Str Light	0.332	0.000	0.000	0.000	627.675	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
41	Cust 902-M Read	1.082	0.912	1.107	1.847	0.000	0.817	8.325	4.612	2.020	5.309	93.753	25.862	0.000	4.727	31.153	28.013	6.304	473.196
42	Cust 903-C R C	7.014	6.046	7.680	11.198	8.312	9.039	46.423	7.094	11.941	30.265	533.479	16.817	6.840	7.078	19.011	152.403	36.241	579.143
43		$13.077	$10.533	$12.648	$24.905	$636.170	$13.674	$94.379	$21.553	$22.425	$60.791	$1,042.452	$103.231	$139.569	$18.841	$131.264	$402.844	$70.920	$2,521.419

EXHIBIT MC-3R
PAGE 5 OF 6

TOTAL	Rate 01 Residential Service	Rate 02 Small General Service	Rate 07 Recreational Lighting	Rate 08 Street Light	Rate 09 Traffic Signs	Rate 11 TOU Municipal Pumping	Rate 15 Electric Refining	Rate 22 Irrigation Service	Rate 24 General Service	Rate 25 Large Power	Rate 26 Petroleum Refinery	Rate 28 Area Lighting	Rate 30 Electric Furnace	Rate 31 Military Reservation	Rate 34 Cotton Gin	Rate 41 City and County	WH Water Heating
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

Note: The amortization of COVID-19 costs have been removed from the rebuttal cost-of-service studies.

EXHIBIT MC-3R
PAGE 6 OF 6

Line	Description	Allocator	Total	Rate 01 Residential Service	Rate 02 Small General Service	Rate 07 Recreational Lighting	Rate 08 Street Light	Rate 09 Traffic Signs	Rate 11 TOU Municipal Pumping	Rate 15 Electric Refining	Rate 22 Irrigation Service	Rate 24 General Service	Rate 25 Large Power	Rate 26 Petroleum Refinery	Rate 28 Area Lighting	Rate 30 Electric Furnace	Rate 31 Military Reservation	Rate 34 Cotton Gin	Rate 41 City and County	WH Water Heating
1	Texas Jurisdiction COVID-19 Amortization	LABOR	$1,535,225	$941,793	$95,365	$1,809	$10,476	$257	$23,666	$4,793	$1,386	$262,389	$83,325	$28,162	$4,614	$2,993	$32,240	$428	$37,872	$3,657
2	Revenue Multiplier	1.36	556,425	341,342	34,564	656	3,797	93	8,577	1,737	502	95,100	30,200	10,207	1,672	1,085	11,685	155	13,726	1,325
3			$2,091,650	$1,283,135	$129,929	$2,465	$14,273	$350	$32,243	$6,530	$1,888	$357,489	$113,525	$38,369	$6,286	$4,078	$43,925	$583	$51,598	$4,982
4	Total kWh		5,934,580,280	2,478,851,326	272,309,109	3,676,526	36,054,763	2,655,162	172,350,354	42,604,774	3,840,029	1,450,801,644	611,107,048	314,641,719	26,829,319	21,568,632	297,329,301	1,596,380	193,240,554	5,123,640
5	Secondary/Primary kWh		5,250,736,561	2,478,851,326	272,309,109	3,676,526	36,054,763	2,655,162	172,350,354		3,840,029	1,450,801,644	603,407,755		26,829,319			1,596,380	193,240,554	5,123,640
6	Transmission kWh		683,843,719							42,604,774			7,699,293	314,641,719		21,568,632	297,329,301			
7	Secondary/Primary Surcharge	Total	$1,465,987	$941,793	$95,365	$1,809	$10,476	$257	$23,666	$0	$1,386	$262,389	$82,275	$0	$4,614	$0	$0	$428	$37,872	$3,657
8	Transmission Surcharge	Total	$69,238	$0	$0	$0	$0	$0	$0	$4,793	$0	$0	$1,050	$28,162	$0	$2,993	$32,240	$0	$0	$0
9	**Secondary/Primary Surcharge**	**$ per kWh**		**$0.000380**	**$0.000350**	**$0.000492**	**$0.000291**	**$0.000097**	**$0.000137**	**$0.000000**	**$0.000361**	**$0.000181**	**$0.000136**	**$0.000000**	**$0.000172**	**$0.000000**	**$0.000000**	**$0.000268**	**$0.000196**	**$0.000714**
10	**Transmission Surcharge**	**$ per bill**		**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$399.42**	**$0.00**	**$0.00**	**$87.48**	**$2,346.83**	**$0.00**	**$249.42**	**$2,686.67**	**$0.00**	**$0.00**	**$0.00**
11	COVID-19 Cost Amortization Per Year	Exhibit CSP-7R	$1,895,742																	
12	Texas Jurisdictional Composite Allocation Factor		0.809828541																	
13	Texas Jurisdiction Amount		$1,535,226																	
14	LABOR Allocation Factor by Rate Class		100.0000%	61.3456%	6.2118%	0.1178%	0.6824%	0.0168%	1.5415%	0.3122%	0.0903%	17.0912%	5.4275%	1.8344%	0.3006%	0.1950%	2.1000%	0.0279%	2.4669%	0.2382%

EXHIBIT MC-4R
PAGE 1 OF 3

Composite Allocator Calculation

Line No.	(a) Account and Description	(b) Total Company [1]	(c) Allocator	(d) Texas [2]
1	506000 - MISC STEAM POWER EXP	$ 82,700	D1PROD	$ 67,032
2	524000 - MISC NUCLEAR POWER EXP	643,900	D1PROD	521,910
3	549000 - MISC OTHER POWER GEN EXP	36,076	D2PROD	29,228
4	556000 - SYSTM CONTROL & LOAD DISP	2,935	DPROD12	2,389
5	566000 - MISC TRANSMISSION EXP	9,598	D2TRAN	7,630
6	586000 - METER EXPENSES	1,885	DIST370	1,492
7	588000 - MISC DISTR EXPENSE	77,018	EXP_58279	48,896
8	903000 - CUST RECORDS & COLL EXP	131,276	CUSTOMER	100,658
9	904000 - UNCOLLECTIBLE ACCOUNTS	803,227	UNCOLL_EXP	623,714
10	921000 - OFFICE SUPPLIES & EXP	632,746	LABOR	499,195
11	923000 - OUTSIDE SVS EMPLOYED	118,966	LABOR	93,856
12	926000 - EMPLOYEE PENSIONS & BEN	544,456	LABOR	429,540
13	COVID-19 related costs included in Cost of Service	3,084,783		2,425,539
14	182399 - OTHER REGULATORY ASSETS	3,213,020	UNCOLL_EXP	2,494,944
15	Total COVID-19 expenses	6,297,803		4,920,484
16	450000 - FORFEITED DISCOUNTS	944,710	DIRECT_TX	944,710
17	Total COVID-19 rider request	$ 7,242,513	0.809828541	$ 5,865,194

Source:
[1] Exhibit CSP-7R
[2] EPE Regulatory Case Working Model-Rebuttal-Dkt 52195

Revenue Multiplier Calculation

EL PASO ELECTRIC COMPANY
2021 TEXAS RATE CASE FILING
SCHEDULE A-1: COST OF SERVICE- RETAIL BY ACCOUNT
SPONSOR: ADRIAN HERNANDEZ
PREPARER: ADRIAN HERNANDEZ
FOR THE TEST YEAR ENDED DECEMBER 31, 2020

SCHEDULE A-1
PAGE 1 OF 1

Line No.	(a) Description	(b) Total Per Books	(c) At Existing Rates Adjustments	(d) At Existing Rates As Adjusted	(e) At Proposed Rates Adjustments	(f) At Proposed Rates As Adjusted
	Operating Revenues					
	Sales Revenues					
	Base Rate Revenues					
1	Base	$ 528,887,914	$ 5,686,206	$ 534,574,120	$ 35,693,538	$ 570,267,658
2	Non-firm	3,642,224	361,503	4,003,727	-	4,003,727
3	Total Base Rate Revenues	532,530,138	6,047,709	538,577,847	35,693,538	574,271,385
4	Fuel Revenues from Retail Sales	81,322,716	(1,350,714)	79,972,002	-	79,972,002
5	Other Sales For Resale Fuel Revenues	65,727,609	97,318	65,824,927	-	65,824,927
6	Total Fuel Revenues	147,050,325	(1,253,395)	145,796,929	-	145,796,929
7	Other Sales For Resale Non-Fuel Revenues	-	-	-	-	-
8	Other Sales Margins Retained by EPE	-	-	-	-	-
9	Provision for Rate Refund	-	-	-	-	-
10	Total Sales Revenues	679,580,462	4,794,314	684,374,776	35,693,538	720,068,314
11	Other Operating Revenues	26,798,328	844,298	27,642,626	(720,634)	26,921,992
12	Total Operating Revenues	706,378,791	5,638,612	712,017,403	34,972,904	746,990,306
	Operating Expenses					
	Operation & Maintenance Expenses					
	Fuel and Purchased Power					
13	Reconcilable	147,472,535	(1,675,605)	145,796,929	-	145,796,929
14	Non-Reconcilable	1,426,324	3,247	1,429,570	-	1,429,570
15	Total Fuel and Purchased Power	148,898,858	(1,672,359)	147,226,500	-	147,226,500
16	Other Operation & Maintenance	250,738,400	(8,383,799)	242,354,601	91,523	242,446,124
17	Total Operation & Maintenance Expenses	399,637,258	(10,056,157)	389,581,101	91,523	389,672,624
18	Regulatory Debits and Credits	790,344	-	790,344	-	790,344
19	Depreciation & Amortization Expense	82,207,721	16,794,927	99,002,648	-	99,002,648
20	Decommissioning and Accretion Expense	7,963,676	(7,851,839)	111,836	-	111,836
21	Taxes Other Than Income Taxes	66,168,599	75,459	66,244,057	2,061,000	68,305,057
22	Current Income Taxes					
23	Federal	10,004,848	2,795,881	12,800,728	6,399,556	19,200,285
24	State	1,525,596	242,035	1,767,631	751,487	2,519,119
25	Total Current Income Taxes	11,530,444	3,037,916	14,568,360	7,151,043	21,719,403
26	Deferred Income Taxes					
27	Federal	9,462,051	(3,748,274)	5,713,777	-	5,713,777
28	State	613,658	380,224	993,882	-	993,882
29	Other					
30	Total Deferred Income Taxes	10,075,709	(3,368,050)	6,707,659	-	6,707,659
31	Amortization of Investment Tax Credits	(1,309,809)	(194,185)	(1,503,995)	-	(1,503,995)
32	Total Operating Expenses	$ 577,063,941	$ (1,561,931)	$ 575,502,010	$ 9,303,567	$ 584,805,577
33	Operating Income (Return)	$ 129,314,849	$ 7,200,543	$ 136,515,392	$ 25,669,337	$ 162,184,729
34	Total Cost of Service	$ 706,378,791	5,638,612	$ 712,017,403	$ 34,972,904	$ 746,990,306
35	Rate Base (Schedule B-1.1)	$ 2,039,760,521	$ (9,158,884)	$ 2,030,601,636	$ 454,782	$ 2,031,056,418
36	Rate of Return on Rate Base	6.340%		6.723%		7.985%
37	Revenue Deficiency @ Proposed ROR on Rate Base	$ 40,611,515		$ 34,972,904		$ (0)

REVENUE MULTIPLIER
1.36

Amounts may not add or tie to other schedules due to rounding.

The following files are not convertible:

Exhibit MC-1R.xlsx
Exhibit MC-2R.xlsx
Exhibit MC-3R.xlsx
Exhibit MC-4R.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.