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

DIRECT TESTIMONY

OF

CLARENCE L. JOHNSON

ON BEHALF OF

THE CITY OF EL PASO

OCTOBER 22, 2021

SOAH DOCKET NO. 473-21-2606
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DIRECT TESTIMONY OF CLARENCE JOHNSON

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I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

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

Q. WHAT IS YOUR OCCUPATION?

A. I am self-employed as a consultant who provides technical analysis and advice regarding energy and utility regulatory issues. I have been retained by the City of El Paso ("CEP" or "City") to testify in this proceeding.

Q. DO YOU HAVE PREVIOUS EXPERIENCE AS AN EXPERT ON REGULATED UTILITY MATTERS IN TEXAS?

A. Yes. I have approximately 38 years of experience as a professional regulatory analyst for the Texas Office of Public Utility Counsel ("OPUC") and as an independent expert witness in proceedings before the Public Utility Commission of Texas ("Commission"), Pennsylvania Public Utility Commission, Maryland Public Service Commission, and the Connecticut Department of Public Utilities.

Q. WHAT WERE YOUR RESPONSIBILITIES AT OPUC?

A. As OPUC's Director of Regulatory Analysis, I was the professional staff person with the primary responsibility for advising the OPUC on economic and regulatory policy issues. My responsibilities included reviewing utility rate applications, recommending actions or positions to be taken by the Office, preparing and presenting expert testimony, and working with other experts employed or retained by OPUC to coordinate the agency's technical evidentiary positions. I also held supervisory responsibilities with respect to OPUC's technical analysis staff. In addition, my responsibilities included providing technical assistance on legislative matters.

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. I have a B.S. in Political Science and a M.A. in Urban Studies from the University of Houston. My graduate degree is in an interdisciplinary program offered by the University of Houston's College of Social Science which incorporated substantial training in economics, including course work in the application of cost-benefit analysis to public policy. During my 25-year tenure at OPUC, I gained experience in virtually all phases of economic review required for the ratemaking process. I was chairman of the Economics and Finance Committee of the National Association of State Utility Consumer Advocates ("NASUCA") and served as a presenter for NASUCA's workshops and panels on cost allocation and rate design, Demand-Side Management ("DSM") incentives, market power and electric utility competition. Also, at various times, I have undergone training in specific subjects such as electric wholesale market design, cogeneration engineering and Electric Reliability Council of Texas ("ERCOT") operations. During my work over the last nine years as a consultant, I have prepared reports, comments, and testimony related to electricity issues for public interest, state agency, and local government organizations. I have testified as an expert witness in over 150 utility rate proceedings. A summary of my educational and professional background is attached as Attachment A.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. My testimony will address selected issues with respect to El Paso Electric Company's ("EPE" or "Company") requested rate design and class cost of service. The City will present other witnesses who address the appropriate revenue requirement level. To the extent my testimony refers to, or utilizes, EPE's proposed revenue requirements, the use of the Company's requested revenues should be considered illustrative in nature, since the City's case disputes the Company's proposed increase in revenues.

Q. PLEASE SUMMARIZE YOUR TESTIMONY RECOMMENDATIONS.

A. My findings and conclusions are summarized below.

- The Company's request to remove $1.2 million in revenues associated with interruptible non-compliance should be denied. This is not non-recurring to the extent that EPE has experienced similar non-compliance in recent years, resulting in similar revenue penalties. My recommendation is to allocate this revenue amount to all firm customer classes, because interruptible non-compliance damages other customers.

- The Company's proposed $1.3 million reduction in revenues to reflect "lost revenues" from the energy efficiency program should be rejected. EPE's adjustment is not known and measurable and is contrary to Commission precedent.

- The Company's load factor calculation for Average & Excess-4CP is reasonable.

- The Company does not provide an explanation for changing the class allocation of imputed capacity associated with solar purchase power contracts from the energy allocator in the previous rate case to D1-Demand allocator in this case. Given the characteristics of these contracts, the E1-energy allocator should continue to be applied. In the alternative, the D12-Demand allocator would be a reasonable option.

- The "general" components of A&G Accounts 920-923 and 930.2 should be allocated on the basis of net plant instead of the labor basis used by the Company. The Company's labor allocator produces a distorted result because salaries and wages for operating and maintaining the Palo Verde Nuclear Station are not included in the allocation. As a result, the labor allocation does not reflect the appropriate underlying costs of EPE's functions. The unusual results for EPE justify an exception to the labor allocation frequently applied to these overhead accounts.

- The Company allocated A&G Account 930.1 (General Advertising) on the basis of customers. This is a change from the Company's previous application of the labor allocator to this account. There is no evidence that the cost of general advertising is driven by the number of customers. I recommend the application of an O&M allocation factor (O&MXUNCOL) to this account, which is consistent with the NARUC cost allocation manual.

- As the Company documents in its testimony, the COVID pandemic resulted in a dramatic impact on 2020 demand and energy allocation factors used in its class cost of service (CCOS) study. The Company's responds to the aberrant demand and energy patterns by applying a capping/floor procedure to the class revenue increases. This response is inadequate to address the pandemic impact on the CCOS study.

- Given the extraordinary impact of the pandemic on the CCOS study, my recommendation is to adjust the demand and energy allocation factors to reflect historical class relationships for the three-year period, 2017-2019. These adjustments permit the CCOS study to be used as a tool to evaluate class limiters applied to the class revenue increases.

- My testimony presents adjusted CCOS results, for both the Company's requested revenue requirement and the revenue requirement recommended by CEP witnesses. Based on the CCOS results, my conclusion is that the Company's proposed 150% capping of the residential revenue increase is not adequate.

- If the Commission awards EPE a material revenue increase, my recommendation is to cap all firm customer classes' revenue at 140% of the total Texas retail percent increase. In addition, if total Texas retail revenues increase, my recommendation is to place a floor of "no increase" on classes which would otherwise receive a revenue reduction. Given the circumstances of this case, awarding some classes a revenue reduction at the same time that overall revenues are increasing is not reasonable. The revenue reductions compound the revenue increases which must be collected from other classes.

- If the Texas retail revenue reduction recommended by CEP witnesses is adopted, my recommendation is to moderate indicated class revenue increases with zero increase and allocate the remaining revenue decrease in proportion to classes' revenue reduction at cost of service.

- EPE overstates the value of incremental generation capacity. As a result, EPE's rate design outlook may place excessive emphasis on the avoided costs associated with demand reduction. Consequently, tempering peak rates in TOU and seasonal rates may be warranted. Furthermore, the Company's measurement of the avoided capacity costs used to value the interruptible tariff conceals the full magnitude of underpricing interruptible demand charges.

- Based on its own calculations, the Company continues to underprice interruptible demand charges. Despite overstated avoided cost, EPE's proposal can achieve its target interruptible credits only by applying a 45% "rate moderation discount" to the interruptible demand charge. Severe underpricing of interruptible rates encourages the

Company to make production decisions which are not cost-based and gives interruptible users an advantage over other less expensive forms of energy efficiency.

- The Company proposed $325 thousand increase in interruptible revenues is insufficient in moving the rate toward avoided cost. My recommendation is to augment the interruptible revenue increase with $1.38 million in additional required revenues. Even with this increase, a 30% rate moderation adjustment still separates the interruptible rate from cost.

- The Company proposes to open the interruptible rate to new customers. Given the underpricing of the interruptible tariff, this is not a cost-effective policy. New customers should be required to receive credits which do not exceed avoided cost. Absent a higher interruptible rate specifically for new customers, the Company's proposed re-opening of the tariff should be denied.

- The residential customer charge should be based on meters, services, and billing and collection costs which vary directly with the number of customers. I have estimated residential customer costs of $5.05 per month. The Company's proposed customer charge of $10.54 can be claimed as cost-based only by including substantial indirect and corporate costs which do not vary directly with the number of customers. Furthermore, a limited customer charge enhances energy efficiency. My recommendation is to maintain the residential customer charge at the current $8.25 monthly charge.

- My recommendation is to reject the Company proposal to: (1) reduce the summer season from six months to four months; and (2) sharply increase differentials between residential summer and winter rates and between summer block rates. In the alternative, if the reduction to four summer months is accepted, my recommendation is to temper the rate differentials in order to avoid potential excessive bills in the summer. This also aligns the seasonal rate differences more closely with more reasonable avoided capacity cost benchmarks.

- With respect to the Company's TOU rate schedules, my recommendation is to temper the peak hour prices by using more moderate avoided capacity costs—reducing the capacity costs by approximately 12% for purposes of calculating peak adders.

- EPE proposes to expand the number of new General Service customers who will be subjected to mandatory TOU rates. The expansion of mandatory TOU rates raises concern regarding the unforeseen risks of this policy. The General Service class has the most diverse types of customers and end uses of electricity. Many businesses are unable to make structural changes in the short term to respond to TOU rates. I recommend two actions to mitigate the risks of mandatory TOU rates. First, the threshold for mandatory TOU rates should be set at 300 kW instead of 200 kW. Second, the mandatory TOU customers should be permitted to shift to standard rates after six months, instead of the 12-month period in the Company's proposal.

II. EPE PROPOSED REVENUE ADJUSTMENTS

A. Interruptible Non-Compliance

Q. PLEASE SUMMARIZE THE COMPANY'S REVENUE ADJUSTMENT FOR INTERRUPTIBLE CUSTOMER NON-COMPLIANCE.

A. The Company deducts $1.21 million from annual revenue. During the test year, an interruptible customer failed to comply with required interruptions. Due to the non-compliance and consistent with the interruptible tariff terms and conditions, the Company rebilled part of the customer's service at firm service rates, plus interest. The Company adjustment to test year revenue excludes this amount as non-recurring revenue.

Q. DO YOU AGREE WITH THIS REVENUE ADJUSTMENT?

A. No. The penalty imposed on this particular interruptible customer may be considered non-recurring for *that* customer, but that does not mean interruptible non-compliance is a non-recurring event. During the past five years, the Company has imposed penalties for interruptible non-compliance in all but one year. If the additional revenue is not included for rate making, the full benefit flows to the Company's shareholders instead of the other customers, who are potentially damaged by the non-compliance.

Q. HOW DID YOU EVALUATE THE COMPANY'S POSITION?

A. Schedule CJ-1 calculates the average rebilled revenue associated with interruptible non-compliance for 2016 – 2020. The amount of rebilling will vary, depending on number of times the customer failed to interrupt in an annual period. This calculation normalizes the value of annual revenues caused by interruptible non-compliance. If the revenue impact of interruptible non-compliance is normalized based on the period 2016 – 2020, the revenue adjustment would be an increase of $280,000, instead of the Company's proposed decrease of $1.21 million. Given that the supposed non-recurring amount is less than the comparable amount normalized over five years, my recommendation is to deny the $1.21 million reduction to annual revenues proposed by Mr. Carrasco. The Company has not shown that the revenue associated with interruptible non-compliance is truly non-recurring.

Q. HOW DID YOU PROPOSE TO TREAT THE ANNUAL REVENUE ASSOCIATED WITH INTERRUPTIBLE NON-COMPLIANCE?

A. I do not dispute the Company's removal of the annual amount from Rate 26 current revenues. However, the $1.21million should be credited to the general body of ratepayers, in order to avoid future windfalls to the Company's shareholders when interruptible customer fail to comply. My recommendation is to allocate the revenue on the D-1 production allocator, similar to the revenues in Account 456-Other Electric Revenues. Crediting the amount to all customer classes recognizes that all customer classes are potentially harmed by interruptible failures. Furthermore, Rate 26 is a signle customer class and if the revenue is allocated to that class, the non-complying customer would benefit from the revenue adjustment.. In my view, that would be contrary to the purpose of imposing a penalty for non-compliance.

B. Energy Efficiency Revenue Adjustment

Q. PLEASE DESCRIBE THE COMPANY'S PROPOSED REVENUE ADJUSTMENT FOR ENERGY EFFICIENCY ("EE") PROGRAM OPERATION.

A. The Company proposes to reduce total Texas class revenues by 21.6 million kWh, or $1.3 million in base revenues to reflect sales reductions caused by the EE program. The adjustment is characterized as an annualization of the EE program energy savings which occurred during the test year.

Q. DO YOU AGREE WITH THE COMPANY'S PROPOSED ADJUSTMENT?

A. No. The adjustment is not known and measurable. The adjustment is not known, because it assumes the Company will meet EE goals for the portion of the adjustment applicable to 2020. These are unverified budgeted savings, which are not acceptable for use in test year data. The adjustment is not measurable because it is based on estimates and forecasts of impacts for the Company's EE program throughout the test year. The EE impacts are already reflected to some degree in the monthly sales data used in the test year. The Company's quantification of the adjustment requires an estimation of the energy efficiency savings embedded in each month of the test year in order to annualize the anticipated end of test year monthly EE savings. Known and measurable adjustments to actual test year data require certainty that the adjustment is known and can be quantified with a high degree of reliability.

Q. IS AN ADJUSTMENT FOR THE REVENUE EFFECT OF EE KWH SAVINGS SUPPORTED BY COMMISSION PRECEDENT?

A. No. The intent of this adjustment is analogous to the lost revenue adjustment mechanism (LRAM) which EPE and other electric utilities previously advocated as part of the EE program cost recovery. The Commission explicitly denied the inclusion of the adjustment in the energy efficiency rule and has consistently rejected such a mechanism.[1] In Docket No. 38339, CenterPoint requested a lost revenue adjustment mechanism *and* an adjustment to test year revenues for the lost revenues associated with the EE program. The Commission ordered parties not to address the lost revenue adjustment mechanism.[2] The Commission did not adopt CenterPoint's adjustment for EE impacts on test year revenues, and entered the following conclusion of law:

> PURA § 39.905 does not provide a means by which an electric utility can raise customer's rates for the electricity they consume based in part on the reduction to load growth that results from the electric utility achieving its energy-efficiency goals.[3]

Q. HAS ANY OTHER TEXAS ELECTRIC UTILITY REQUESTED AN ENERGY EFFICIENCY ANNUALIZATION ADJUSTMENT SIMILAR TO EPE'S PROPOSAL?

A. Yes. CenterPoint requested a similar revenue adjustment in its most recent rate case, Docket No. 49421. The PFD in that case firmly rejected the proposed adjustment. According to the PFD, the "similarities between the EEP adjustment and CenterPoint's prior LRAM proposals warrant identical treatment by the Commission in this proceeding."[4] According to the PFD, the deemed savings calculation which forms the

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[1] *Application of CenterPoint Energy Houston Electric, LLC to Defer Energy Efficiency Cost Recovery and for Approval of an Energy Efficiency Cost Recovery Factor*, Docket No. 38213, Supplemental Preliminary Order (June 23, 2010). "Neither P.U.C. SUBST. R. 25.181 nor PURA—either § 36.204 or § 39.905—permit a lost revenue adjustment mechanism (LRAM) to be recovered in a utility's EECRF."

[2] *Application of CenterPoint Electric Delivery Co. to Change Rates*, Docket No. 38339, Order on Rehearing at Finding of Fact No. 21 (June 23, 2011).

[3] *Id.* at Conclusion of Law No. 23.

[4] *Application of CenterPoint Energy Houston Electric, LLC for Authority. to Change Rates*, Docket No. 49421, Proposal for Decision at 338 (Sept. 16, 2019).

basis for the revenue adjustment is "inherently imprecise."[5] The parties submitted a black box settlement to the Commission subsequent to the issuance of the PFD. Although the settlement obviated the need for the Commission to rule on this issue, the PFD provides support for my conclusion that an energy efficiency revenue adjustment should be denied.

Q. IS THE COMPANY UNDULY BURDENED BY DENYING A LOST REVENUE ADJUSTMENT?

A. No. In developing the energy efficiency rule, Commission attempted to provide balanced treatment of utility investor interests. The rule provides an energy efficiency bonus for the electric utility's shareholders. For the period 2017 thru 2019, EPE was awarded energy efficiency bonuses in excess of $2.5 million.[6] These bonuses are pure profit for EPE's shareholders and should compensate investors for bearing any risk of energy efficiency revenue losses.

Q. PLEASE EXPLAIN HOW THE COMPANY'S PROPOSAL EXPANDS THE TRADITIONAL TEST YEAR CONCEPT.

A. The test year data already includes the actual impact of any conservation or load management activities which occurred in the test period. The revenue impacts are embedded in the actual test year. In order to annualize the EE lost revenue impact, the Company's adjustment first has to estimate the EE program impacts which are embedded in the test year. In order to annualize these estimated impacts, the Company

[5] Ibid.

[6] EPE requested bonuses of $824, 000, $928,000, and $809,000 for the 2016, 2017, and 2018 energy efficiency program years.

then must estimate the timing and duration of the EE program impacts across each month of the test year period. This latter calculation is a quantification outside of the normal requirements of the EE rule. Thus, the Company's adjustment is based on combining two estimation procedures.

Q. IS THE EE REVENUE ADJUSTMENT JUSTIFIED IF THE COMPANY USES THE ENERGY EFFICIENCY RULE'S CALCULATION METHODS?

A. No. The fact that measurement of the EE program impacts may be acceptable for determining compliance with the EE goals does not prove the measurements are accurate and reliable enough to be considered a known and measurable adjustment to the test year. The procedures required by the EE rule are intended to satisfy several criteria, including transparency and consistency, but are not developed with the objective of establishing the actual level of rate case sales. The EE Rule provides for estimation of energy savings over a 5 – 15-year EE measure's life. This type of projection is not designed for rate case adjustments to a test year. Moreover, most of the savings' calculations used for EPE's adjustment are deemed savings. Deemed savings are generic savings values permitted by the EE rule, in contrast to actual measurement of specific program actions. Deemed savings may be stipulated values or may contain input assumptions deemed acceptable without specific testing. These generic values frequently are based on average conditions and behavior, which may vary from actual practice. As noted by the PFD in Docket No. 49421, deemed savings values are inherently imprecise.

Q. IS THE EPE ADJUSTMENT BASED ON VERIFIED EE SAVINGS?

A. No. Mr. Carrasco's testimony states that the savings values currently are unverified—i.e., the actual implementation of measures is not confirmed—which means that the values simply represent EPE's goals.[7] However, even if the Company subsequently substitutes verified values, the reliability of the calculations are subject to a range of uncertainty for several reasons:

- EE program energy savings are dependent upon the individual behavior of program participants, which is difficult to incorporate in measurement calculations.
- The Company's use of the program saving expectations also must assume how quickly the program results materialize over the course of the test year..
- EE programs typically are designed to produce kW demand savings. In order to convert demand savings into kWh savings, the Company uses assumed capacity factors for each program (also known as conservation load factors). The capacity factor represents the ratio between maximum demand savings and annual average kWh savings. However, projected capacity factors can vary from actual capacity factors. For example, in the aggregate, EPE's actual conservation load factors in 2018 and 2019 are 21% below the projected factor. This increases the uncertainty associated with estimated kWh savings.

Q. PLEASE EXPLAIN HOW INDIVIDUAL PARTICIPANT BEHAVIOR CAN ALTER THE ACCURACY OF SAVINGS ESTIMATES.

A. "Free ridership" is a well-known issue in measuring energy efficiency program savings. Free-riders are participants who undertake the energy savings action even in the absence of the EE program inducement. The potential effect is for the Company's adjustment to double count energy savings already embedded in the test year. Another behavioral issue is sometimes called the "snapback effect," because participants may choose to run their air conditioning or heaters more frequently after the EE measure

[7] Carrasco direct testimony at 10.

has been installed and begins to produce bill savings. In effect, participants may choose to improve temperature comfort levels in lieu of energy reductions. Deemed savings may include assumptions regarding free-rider impact, but there is no assurance that program participants will behave as assumed.

Q. PLEASE SUMMARIZE YOUR RECOMMENDATION.

A. I recommend rejection of the Company's proposed revenue adjustment for EE savings. Schedule CJ-2 shows the amount of the Company's revenue adjustment by class, which should be reversed based on my recommendation.

III. CLASS COST OF SERVICE STUDY

A. Overview

Q. WHAT IS A CLASS COST OF SERVICE ("CCOS") STUDY?

A. The CCOS is a fully-allocated cost study that distributes the Company's costs to customer classes. The intent of the study is to allocate costs based on cost causation, generally resulting in a portion of costs allocated on causal measures and the remainder of indirect costs following those costs. The CCOS is at best a broad benchmark for evaluating customer class cost responsibility. The CCOS can provide guidance to the regulator, but considerations other than the CCOS are also appropriate in determining the ultimate allocation of costs among customer classes.

Q. HOW IS THE COST CAUSATION CRITERION APPLIED IN THE CCOS?

A. Some costs are incurred directly to serve only an individual customer or set of customers. For example, substations are sometimes dedicated to serving an individual customer and can be directly assigned.

However, the provision of electric utility service is predominated by common and joint costs, which either support the overall enterprise or produce shared benefits for all or most customers. These costs often are assigned based upon indirect, and often weak, measures of causation. For example, overhead costs, such as Board of Director fees, might be allocated based upon measures as diverse as revenues, labor costs, energy sales, or rate base. No single objective economic basis supports the allocation of these costs; therefore, the allocation decisions are subjective or based on rate making conventions. Ideally, the analyst selects a method that best recognizes the manner in which customer classes' characteristics contributed to the incurrence of utility investments and expenses. The manner in which a utility plans and installs an investment often informs the analyst's evaluation of causal factors related to classification or allocation of the investment.

The three major steps of the embedded cost of service study are functionalization, classification, and allocation. Functionalization is the procedure for separating costs into functional segments, such as production, transmission, and distribution. The next two accounting steps, classification and allocation, facilitate the recognition of causation. The classification procedure, which pools costs into general categories of causation (i.e., demand, customer, energy) is an intermediate step in determining the allocation factors that are used to divide costs among jurisdictions and customer classes.

Q. DO BUNDLED ELECTRIC UTILITIES LIKE EPE HAVE MORE COMPLEX ALLOCATION ISSUES?

A. Yes. The classification of generation (production) costs is particularly controversial. Generation systems are complex and require minute to minute dispatch of generation resources in order to meet real time demand at the lowest cost. As part of the system planning process, the utility plans to acquire or install a mix of generation capacity sufficient to meet the system reserve margin at the lowest projected present value of revenue requirements. Because the capital cost or capacity charge of generation generally varies inversely with the generation resource's running cost, the expected hourly output of the resource is an important determinant of system planning decisions[8]. Both reliability and load duration are considerations in reflecting cost causation for generation. Reliability is recognized through class peak demands. Load duration is reflected through class energy use or multiple hours of demand (such as the 12-month class peaks). Given the various weightings and combinations of methods to reflect reliability and load duration, the NARUC Electric Utility Cost Allocation Manual identifies approximately 30 different production cost allocation methodologies.

Q. PLEASE DESCRIBE YOUR REVIEW OF EPE'S CCOS STUDY.

A. I evaluated the study for consistency and accuracy in the allocation of costs among classes. Based on my review, the allocation or classification of several cost elements were identified as insufficiently justified or warranting improvement. My testimony proposes modifications to the treatment of those costs in the Company's CCOS study. My recommendations are limited to the classification and allocation of costs in the

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[8] The NARUC Electric Utility Cost Allocation Manual describes the effect of generation system planning trade-off on the classification and allocation process at p. 53.

Texas retail CCOS study and can be applied separately from the treatment of those costs in the jurisdictional study. My recommendation focuses on a limited number of CCOS issues; omission of other issues should not be construed as agreement with all other aspects of the Company's study.

B. Production Demand Costs

Q. WHAT ALLOCATION METHOD DOES EPE UTILIZE FOR PRODUCTION DEMAND COSTS?

A. The Company uses Average & Excess Demand-4 CP (AED-4CP) for most of its generation demand costs. EPE utilizes 4 CP demands for peaking generation. In addition, the Company uses 12 CP demands for production dispatch and control expenses.

(1) AED-4CP METHOD

Q. HOW IS PEAK DEMAND MEASURED IN PRODUCTION COST ALLOCATION METHODS?

A. Usually customer class demands are measured during the hours of system peaks, and therefore are referred to as "coincident peaks" ("CP"). The number of monthly peaks can vary depending on the particular variant of methodology. For example, 4CP is based on the coincident peaks for each of the four summer months. Some utilities utilize 12CP, which is based on the average coincident peak for each month of the year. 4CP emphasizes summer season contribution to cost causation, and 12CP is based on production demands throughout the year.

Q. WHAT PRODUCTION DEMAND ALLOCATION METHOD IS USED BY THE COMPANY'S CCOS?

A. EPE utilizes the Average & Excess Demand-4CP ("AED-4CP") method, a production demand methodology frequently proposed by utilities in Texas.[9] 4CP is the measure of peak demand in the methodology. As indicated by the name of the method, AED-4CP is comprised of two principal components, annual average hourly demand ("Average Demand") and Excess Demand. Excess Demand is the difference between class average demand and class 4CP demand. Load factor (EPE Average Demand divided by 4CP Demand) is used to weight the components of the formula. Although AED-4CP appears to give significant recognition to energy, the formula has an algebraic construction which cancels most of the impact of average demand on the formula's results. For that reason, AED-4CP is primarily a peak demand responsibility method that is driven by the four-summer month peak hours. Depending on the calculation of load factor and the treatment of lighting classes, the AED-4CP method usually produces results the same as, or very similar to, a 4CP demand methodology.

Q. WHAT IS YOUR OPINION OF THE AED-4CP METHOD?

A. AED-4CP has several weaknesses, most notably its ineffectiveness in recognizing the load duration facet of generation cost causation. I would prefer 12CP or one of the NARUC Manual methodologies which more effectively reflects energy input, such as Peak & Average, dispatch-based approaches, or the Base-Intermediate-Peak method. Given the magnitude of Palo Verde Nuclear Generation Station costs, a strong argument can be made that the baseload characteristics justify the use of either 12CP or Peak & Average production demand methods. However, in this case, given the

[9] The formula for AED-4CP is as follows: Class Allocation Factor = [(LF * Class Avg. Demand)] +[(1-LF) *(Class 4CP - Class Avg. Demand)] LF is "load factor" or Avg. Demand/divided by 4CP.

Commission's prior acceptance of AED-4CP, I have accepted the methodology in order to reduce controverted issues.

Q. HAS THE COMPANY CALCULATED AED-4CP DIFFERENTLY IN RECENT RATE CASES?

A. Yes. The Company proposed a change to the load factor component of the formula in its last rate case, Docket No. 46831[10]. In this case, the Company proposes to return to the load factor component it used in Docket No. 44491[11] and prior rate cases. In the current proposal and the filing in Docket No. 44491, the load factor component is based on 4 CP, instead of a 1 CP load factor proposed in Docket No. 46831. A higher load factor increases the influence of average demand on the results of the formula, thereby allocating more cost to higher load factor classes. EPE's version of the formula in Docket No. 44491 utilized a load factor based on the 4CP load factor, but, in Docket No. 46831, the Company's filing changed the load factor to a measure based on 1 CP. The practical difference is that the 1 CP load factor is a lower value and thereby decrease the impact of average demand on the formula's allocation factors.[12] Therefore, the 1 CP load factor, as used in Docket No. 46831, increases production costs allocated to low load factor classes (like residential) and decrease production costs allocated to high load factor classes (like industrial classes). In the current case, the Company's proposal to utilize a 4 CP load factor is consistent with my recommendation in Docket No. 46831. Although the effect of this change is relatively

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[10] *Application of EL Paso Electric Company to Change Rates*, Docket No. 46831 (Order Dec. 18, 2017)
[11] *Application of EL Paso Electric Company to Change Rates*, Docket No. 44491 (Order Aug. 25, 2016)
[12] Load factor equals average demand divided by the measure of peak demand. Because Average 4 CP is almost always less than 1 CP, the 4 CP load factor is a ratio mathematically lower than the 1 CP load factor.

small, the revision results in an allocation consistent with AED-4CP methods previously used by EPE, as well as the circumstances specific to EPE.

Q. DO YOU AGREE WITH EPE THAT THE AED-4CP FORMULA SHOULD UTILIZE 4 CP LOAD FACTOR?

A. Yes. When coincident demands are used in the AED formula, the load factor should be consistent with the formula's measure of coincident demands—in this case 4 CP. If the load factor doesn't match the measure of peak demand, some classes' allocation factors may fall outside the boundaries of average demand and 4 CP demand, which is not a reasonable result.

Q. DOES THE NARUC COST ALLOCATION MANUAL (CAM) PROVIDE GUIDANCE ON THE LOAD FACTOR APPLICABLE TO AED-4CP?

A. No. The NARUC CAM does not address AED-4CP as an acceptable method. The NARUC CAM identifies AED as a non-coincident demand methodology. In fact, the NARUC Cost Allocation Manual states that coincident peak demands should not be used in the AED method. Therefore, the CAM cannot provide meaningful guidance on the load factor component for AED-4CP.

Q. PLEASE SUMMARIZE YOUR POSITION.

A. The AED-4CP formula used to allocate EPE generation capacity should employ a 4 CP load factor, as proposed by the Company in this case.

(2) ALLOCATION OF IMPUTED SOLAR CAPACITY

Q. HAS EPE MADE ANY OTHER CHANGE TO THE ALLOCATION OF PRODUCTION CAPACITY?

A. Yes. The Company has changed the allocation of Account 555-Purchase Power (Non-Reconcilable) from an energy allocation in Docket No. 46831 to AED-4CP in this filing.[13] The Company's testimony does not discuss this change in allocation. The components of this account consist of imputed solar capacity charges.[14]

Q. WHAT IS A CAPACITY IMPUTATION?

A. Capacity imputation is a treatment of purchase power which converts part of the contract energy charges to capacity charges. For the Macho Springs and Newman solar contracts, the Company includes $1.69 million as capacity charges in Account 555.[15] The primary impact of this rate treatment is to reflect part of the contract costs as non-reconcilable.

Q. DO YOU AGREE WITH THE ALLOCATION CHANGE MADE FOR THESE RESOURCES?

A. No. Energy is a more reasonable allocation than AED-4CP for solar resources. An allocation that focuses on the 4 summer peak hours, like AED-4CP is not a reasonable representation of cost causation for solar generation. First, the maximum monthly output for these two solar contracts occurs outside the four summer months.[16] Moreover, the capacity value of the solar generation is diurnal, rather than seasonal, in nature. Second, the solar generation is not dispatchable, which means the resources must be backed up by other resources in the event that weather reduces the solar contribution during peak periods. Third, the primary benefit of solar generation is

[13] Schedule P-2 (Errata No. 3), line 64. [Compare to Schedule P-2, Docket No. 46831.]
[14] EPE Response to CEP Request No.14-12.
[15] Ibid.
[16] EPE Response to CEP 14-12, Attachment 1.

reduction in the system's fuel expense. If an electric utility purchases solar generation over other power sources available in the market, the principal reason is to avoid fuel expense and reduce volatility associated with gas prices. If a market-based capacity charge is paid, the rationale for such a charge is to gain access to the price stability offered by solar power.

Q. PLEASE SUMMARIZE YOUR RECOMMENDATION.

A. Because the Company provides no explanation for changing the energy allocation applied to non-reconcilable solar generation expense, my recommendation is to apply the energy allocator (E1) to the expense. In the alternative, a 12 CP allocator (D12) is also reasonable, given that the demand-related benefit of solar power is diurnal rather than seasonal in nature.

C. Covid-19 Impact on External Allocation Factors

Q. IS THE EPE CCOS STUDY AFFECTED BY ABNORMAL CLASS USAGE EFFECTS IN THIS CASE?

A. Yes. The Company's CCOS utilizes class demands and energy from the 2020 test year. Beginning in the second quarter of 2020, the COVID 19 pandemic imposed extraordinary impacts on particular customer classes' electricity usage. In addition to severe negative economic effects due to the pandemic, the health protocols caused a large number of residential customers to stay at home during the normal work week and led to closures of certain types of businesses. As a result, demand and energy allocation factors for the residential class are higher than normal, and the same allocation factors for major commercial, industrial, and city/county classes are lower than normal. Because internal allocation factors are driven to a large extent by external demand and energy factors, the abnormal class usage patterns have a cascading effect on the CCOS study result.

Q. DOES THE COMPANY'S TESTIMONY RECOGNIZE THAT THE COVID-19 IMPACT CAUSED ANOMALOUS RESULTS IN THE CCOS STUDY?

A. Yes. EPE witness Mr. Novela states: "The COVID-19 pandemic resulted in a shift in usage patterns over the test year due to business and government office closures and employees working from home as opposed to the office."[17] In addition, Mr. Novela expects "customer usage patterns to start returning to normal as the pandemic improves, meaning a reduction in usage by its residential customers and an increase in its commercial and city/county customers from the significant changes witnessed over 2020."[18] According to EPE witness Mr. Carrasco, the allocation factors reflect that "cost shifting has occurred from non-residential classes to the residential class."[19] Mr. Carrasco observes that COVID-19 impacts caused test year residential allocation factors to increase by 500 – 1,100 basis points and general service demand allocation factors to decrease by 200 – 600 basis points, relative to historical experience.[20]

Q. IS EPE'S EXPERIENCE WITH COVID-19 CUSTOMER CLASS IMPACTS SUPPORTED BY NATIONAL DATA?

A. Yes. The National Bureau of Economic Research (NBER) sponsored a study of electricity usage during the pandemic.[21] The study is based on data from ERCOT smart

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[17] Novela at 10.
[18] Ibidem.
[19] Carrasco at 16.
[20] Ibidem.
[21] "Powering Work from Home," Steve Cicala, Oct. 2020, NBER Working Paper 27937, Powering Work from Home | NBER https://www.nber.org/papers/w27937

meters, as well as U.S. Energy Information Administration (EIA) 2019 – 2020 data. Conclusions from the study include:

- "This paper documents an increase in residential electricity consumption while industrial and commercial consumption has fallen during the COVID-19 pandemic in the United States"[22]

- "The 16% residential increase during work hours offsets the declines from commercial and industrial customers. Using monthly data from electric utilities nationwide, I find a 10% increase in residential consumption, and a 12% and 14% reduction in commercial and industrial usage, respectively, during the second quarter of 2020."[23]
- "Hourly smart meter data from Texas reveals how daily routines changed during the pandemic, with usage during weekdays closely resembling those of weekends."[24]

- "While total U.S. electricity consumption returned to normal levels in July 2020, industrial and commercial users were still 5% below normal on average."[25]

Q. HOW DID THE COMPANY ADDRESS THIS ISSUE?

A. According to Mr. Novela, EPE considered adjustments to test year allocators based on historical experience, but chose not to employ "a previous year set of allocators" due to uncertainties in predicting how quickly class usage will return to normal patterns.[26] Instead, as part of the class revenue allocation procedure, the Company applied caps and floors "to the rates that showed a significant deviation from past usage patterns to account for the abnormalities witnessed in 2020 that are not expected to fully be carried forward."[27] Mr. Novela opines that the rate change limiter[28] "incorporates the pandemics impact on usage while at the same time limiting the most significant

[22] Ibidem at Abstract.
[23] Ibidem.
[24] Ibidem.
[25] Ibidem at 2.
[26] Novela at 11, l. 1-3.
[27] Novela at 10, l.17-19.
[28] The Company proposes a 150% cap on the Residential class percentage increase and cutting certain classes percentage decreases in half.

deviations that are not expected to continue."[29] Despite this hopeful explanation, the Company's testimony does not demonstrate that the cap/floor procedure is sufficient to compensate for the pandemic's impact on usage; nor does the Company specify the "most significant deviations," as referenced by Mr. Novela, which are not expected to continue.

Q. WHAT IS YOUR POSITION REGARDING THE APPROPRIATE RATE MAKING TREATMENT OF PANDEMIC IMPACTS ON CLASS USAGE?

A. Under the circumstances, I believe two general alternatives can be justified. First, given the over-arching impact of the pandemic on CCOS study allocation factors, one could conclude that a CCOS study based on the 2020 test year is inherently flawed and incapable of providing accurate information to the rate making process. The remedy for a defective CCOS study is to maintain current class relationships by adopting an equal percentage change in rates. The second alternative is to adjust allocation factors of affected classes in order to reflect historical patterns prior to the pandemic. Although this approach may not provide the precision normally expected for CCOS studies, I contend that the COVID impact is an extraordinary and exceptional circumstance which justifies the use of adjustments based on pre-pandemic allocation data. The advantage of this second alternative is that the CCOS study can be used as an objective benchmark to justify differential percentage rate changes among classes. Therefore, I will incorporate allocation adjustments which are intended to exclude COVID impacts.

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[29] Novela at 11, l. 5-6.

Q. DOES THE COMPANY'S CAP/FLOOR APPROACH TO CLASS REVENUE ALLOCATION OBVIATE THE NEED TO ADJUST ALLOCATION FACTORS FOR COVID?

A. Not in my opinion. Rate moderation limits may be a useful step in addressing COVID impact. However, without an adjusted CCOS study, no benchmark is available to evaluate whether the cap and floor limits are an adequate and reasonable response to pandemic usage impacts. Therefore, I will include allocation factor changes among the adjustments to my recommended CCOS study. My testimony will then examine rate moderation tools in relation to the adjusted CCOS study results.

Q. HOW DID YOU REVISE THE DEMAND AND ENERGY ALLOCATION FACTORS?

A. The following six classes were adjusted: Residential, Small General Service, General Service, Large General Service, Petroleum Refining, and City/County. For these classes, three-year average allocation factors for the period 2017 – 2019, based on Mr. Carrasco's exhibit MC-5, are substituted for the 2020 allocation factors. As a generalization, the decrease in the residential allocation factor is offset by the cumulative increase in the allocation factors for the five non-residential classes. A more detailed explanation of my methodology is discussed in Attachment B.

Q. DID YOU ALSO APPLY AN ADJUSTMENT TO THE SIX CLASSES' EXISTING REVENUE IN THE CCOS STUDY?

A. Yes. The allocation factor adjustment implies that residential revenues are overstated and revenues for the five non-residential classes are understated. My methodology identifies the increase in residential revenues between 2019 and 2020, and then estimates the portion of the residential increase attributable to COVID impact, which is removed from residential existing revenue and added to the existing revenues of the five non-residential classes. As a result, $14.9 million is removed from residential existing revenue and added to the five non-residential classes' revenues in proportion to the increase in the classes' cost of service. This adjustment to class revenues does not affect the Total Texas requested revenue increase. This step is also discussed in Attachment B.

Q. HOW DOES THIS AFFECT YOUR RECOMMENDATION?

A. The demand and energy allocation adjustments are intended to produce normalized allocation factors for the affected classes. The adjusted allocation factors are included in my recommended CCOS study. The CCOS result is used to evaluate and adjust the Company's cap and floor proposal. The CCOS study is always an estimation process, and in this case the COVID pandemic has created additional uncertainty and imprecision in the CCOS result. Given that context, the CCOS study is best utilized to evaluate rate moderation constraints. The adjustments to the CCOS study for aberrant usage pattern provide a more reasonable benchmark for evaluating class revenue change limits.

D. Allocation of A&G Accounts 920, 923, And 930

Q. DESCRIBE ADMINISTRATIVE & GENERAL ("A&G") ACCOUNTS 920-923?

A. As a matter of accounting definition, Account 920 contains salaries and wages which cannot be attributed to any particular function of the utility. Examples of typical expenses include the chief executive officer, general corporate officers, the treasury and finance departments, the human resources department, corporate strategic planning, shareholder services, and the like. Account 923 consists of outside services which cannot be attributed to particular functions of the utility. These are common costs of the corporation which are only weakly associated with any particular class allocation factors.

Q. FOR PURPOSES OF THE CCOS STUDY, SHOULD UTILITIES ATTEMPT TO IDENTIFY A&G EXPENSES WHICH CAN BE ASSOCIATED WITH PARTICULAR FUNCTIONS?

A. Yes. The Commission's filing forms encourage utilities to assign such general costs to particular functions of the utility if it can be readily determined through investigation. EPE allocates some components on the basis of production, transmission, distribution, or customer functions. However, EPE classifies 91% of Accounts 920 and 923 as "General," to be allocated on an indirect allocator.

Q. HOW DOES EPE ALLOCATE THE GENERAL COSTS IN ACCOUNTS 920 AND 923 TO CUSTOMER CLASSES?

A. The Company allocates the general expense in proportion to labor costs within each functional category (allocator labeled Labor excluding A&G). [30] In this particular case, my recommendation is to modify the allocation basis for the unassignable general expenses in Account 920 and 923.

[30] Note that each functional group (such as production, transmission, or distribution expense) includes the supervisors for the function's labor force within a separate supervisory account, rather than A&G expense. Thus, A920 management salaries are not directly involved in supervising the workers included in labor excluding A&G.

Q. WHAT IS THE PROPER CRITERION FOR SELECTING AN APPROPRIATE INDIRECT ALLOCATOR FOR GENERAL COSTS IN ACCOUNTS 920 AND 923?

A. Because none of the potential allocators are strongly related in a causal sense to these A&G accounts, the selection should focus on the extent to which the allocator spreads corporate overhead broadly and equitably across corporate functions. The costs that are allocated support the overall enterprise. A reasonable general allocator should not be tilted in a direction that is out of proportion to the overall composition of costs. In this case, the labor allocator does not produce balanced results.

Q. WHY DO YOU PROPOSE TO CHANGE THE USE OF A LABOR ALLOCATION FOR THIS ACCOUNT?

A. The use of a labor allocator for A&G Accounts 920 and 923 is not unusual. But the composition of EPE's labor allocator produces incongruent results, which justifies rejection of the allocator for general corporate salaries and outside services. Because Arizona Public Service operates the jointly owned Palo Verde Nuclear Generation Station, EPE's CCOS study does not include Palo Verde payroll within the labor allocation factors (except for a few EPE employees on-site). Although Palo Verde constitutes approximately 40% of non-fuel production expense, the plant's labor expense is not included in the labor allocator. As a result, the labor allocation will understate the magnitude of the production function relative to EPE's overall operations. For this reason, an exception to the typical practice of using a labor allocation for Accounts 920 and 923 is justified. However, I would continue to apply the labor allocator to A&G expenses directly related to payroll, such as pensions and benefits, employment taxes, and labor related injuries and damages.

Q. CAN YOU DEMONSTRATE THAT THE OMISSION OF PALO VERDE PAYROLL FROM THE LABOR ALLOCATOR DISTORTS THE RELATIVE IMPORTANCE OF PRODUCTION TO THE COMPANY'S COST STRUCTURE?

A. Yes. The labor allocator spreads indirect costs to the utility's functions (production, transmission, distribution, customer) in proportion to direct payroll within each function. Thus, the allocation of indirect cost to customer classes will follow the functional assignment. Customer classes are responsible for varying proportions of each function. All firm classes pay for production costs, but transmission voltage classes are not responsible for distribution costs, and the allocation of customer costs is highly tilted toward the residential and small general service classes with numerous customers. Allocating a lower proportion of indirect costs to production tends to favor large industrial customers because a larger part of their bundled rate is generation. In order to illustrate the impact of Palo Verde on the labor allocator, I compared an adjusted labor allocator (which includes Palo Verde salaries for EPE's share of the plant[31]) with the actual labor allocator used in the CCOS study. If Palo Verde salaries had been included in the labor allocation, 59**%** of general expense in Accounts 920 and 923 would have been allocated based on production. By comparison, the Company's method allocates **34%** of general expenses on the basis of production. Since 65% of

[31] EPE share of 2020 Palo Verde straight time wage and salary expense derived from EPE Response to CEP 9-4, Attachment 1. EPE's share of this payroll is invoiced as an expense, and therefore is not included in the CCOS study wage and salary distribution.

non-fuel revenue requirement is production,[32] the Company's labor allocator significantly understates the contribution of the production function to EPE's cost structure.

Q. WHAT ALLOCATOR DO YOU RECOMMEND FOR GENERAL EXPENSES IN ACCOUNTS 920 AND 923 WHICH THE COMPANY ALLOCATES ON LABOR?

A. My recommendation is to apply the net plant allocator instead of the general labor allocator.[33] I performed a comparison of internal allocation factors. The net plant allocator provides a more balanced representation of functional proportions than the labor allocator. The table below shows the functional ratios associated with the Company's CCOS labor allocator, an adjusted labor allocator (includes Palo Verde wages and salary), net plant allocator, allocation based on non-fuel O&M expense, and revenue requirements.[34] The Company's labor allocator produces anomalous results compared to the other methods. Although a labor allocator including Palo Verde salaries would be reasonable, it is difficult to incorporate a new internal allocator into the Company's CCOS model. The net plant allocator provides reasonably comparable

Indirect Allocator	Production	Transmission	Distribution	Customer
Labor	34%	21%	28%	17%
Labor-PVNGS included	59%	13%	17%	11%
Net Plant	54%	12%	32%	2%
O&M Expense	75%	8%	10%	7%
Revenue Req.	65%	11%	19%	5%

[32] EPE Response to Staff 8-01 Attachments 1 & 2; Schedule P-1.03.
[33] An internal allocator based on non-fuel O&M excluding A&G expense would also be reasonable.
[34] All of the data shown here exclude A&G expense and General Plant.

results relative to the remaining allocation methods and is generally consistent with Company's cost structure.

Q. IS NET PLANT REASONABLY RELATED TO THE ACTIVITIES OF PERSONNEL ENCOMPASSED IN ACCOUNT 920?

A. Yes. This account contains the salaries of corporate officers with responsibility for the full corporate entity, as well as finance, treasury and legal department professionals. Presumably the top management of the Company pays particular attention to capital commitments and investments, as well as debt obligations resulting from capital outlays. Moreover, plant in service forms the basis for utility earnings, which the officers of the corporation have a responsibility to protect. Furthermore, as shown above, plant in service is reasonably related to the Company's revenue requirements. The personnel involved in general management are concerned with all of the utility functions that comprise the utility's revenue requirements.

Q. HAVE YOU CHANGED THE ALLOCATION OF ACCOUNT 930, MISCELLANEOUS GENERAL EXPENSE?

A. Yes. $2.7 million of "Other Expenses" in Account 930.2, Miscellaneous General, is categorized as "General" and allocated on a labor basis by the Company. For this component of Account 930.2, I recommend changing the allocation from labor to net plant. The reason for this change is the same as stated for Accounts 920 and 923. The expenses in this account are not directly related to payroll, and the labor allocator does not spread the indirect expenses across functions in a balanced manner, because labor components for Palo Verde are excluded. Expenses included in this account include payments to industry organizations such as Edison Electric Institute (EEI) and Chambers of Commerce, and costs for mailing dividends, publishing the corporate annual report, stockholder meeting expenses, and board of director costs. Expenses in this account are general corporate costs which are reasonably related to the Company's capitalization and plant-in-service.

Q. HAVE YOU ADDRESSED ACCOUNT 930.1 GENERAL ADVERTISING?

A. Yes. The Company proposes to allocate $1.179 million of general advertising on a customer basis. This is a change from the labor allocator that the Company used for this account in its last rate case. I do not agree with allocating general advertising on a customer basis, which requires the residential class to pay almost 90% of the expense. My recommendation is to allocate this expense on the basis of non-fuel O&M expense. A customer allocation for this expense is not consistent with the guidance of the NARUC Electric Utility Cost Allocation Manual (CAM). The NARUC CAM recommends either an allocation based on "Non-Fuel O&M Excluding Fuel and Purchased Power" or "Labor" as the preferred methods for Account 930.1. [35] My recommendation aligns with the former option, and the latter option is consistent with the allocation utilized by the Company's CCOS in Docket No. 46831. Either allocation approach is preferable to the very narrow allocation utilized in the Company's proposed CCOS.

Q. DOES THE NATURE OF GENERAL ADVERTISING SUPPORT A CUSTOMER ALLOCATION?

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[35] NARUC Cost Allocation Manual at 107.

A. No. FERC account 930.1 records the cost of image advertising, and there is no inherent reason that this amount will vary in proportion to the number of customers.[36] Image advertising may also have the objective of creating more favorable opinions of the utility among investors, public officials, or other influential persons. Such advertising is not linked to customers, but instead is motivated to advance the interests of the utility. These costs are generalized expenditures which (if recoverable) should be spread through a broad indirect allocator across the utility's functions. The customer allocator is a narrow allocation basis which does not reflect all of the functions of the utility.

E. Summary of CCOS

Q. HAVE YOU PREPARED A SUMMARY OF THE COMPANY'S CCOS STUDY WITH YOUR ADJUSTMENTS?

A. Yes. Schedule CJ-3 summarizes the Company's proposed revenue increase with my proposed changes to the Company's CCOS Study. Based on this result, my conclusion is that the Company's 150% capping of the residential class is inadequate.

Q. ARE THESE ALLOCATION CHANGES INCORPORATED IN THE CITY'S CASE?

A. Yes. I have provided the allocation changes to Mr. Karl Nalepa, a CEP witness who incorporated my recommended adjustments, as well as the adjustments proposed by

[36] Note A for this account in the FERC chart of accounts refers to "the cost of advertising activities on a local or national basis of a good will or institutional nature, which is primarily designed to improve the image of the utility or the industry…"

other CEP witnesses, into the Company's rate case model. Schedule CJ-4 provides the results of the City's case, both revenue requirement and class allocation.

IV. <u>REVENUE DISTRIBUTION</u>

Q. PLEASE DESCRIBE THE ISSUES REGARDING REVENUE DISTRIBUTION.

A. Rate design involves the following major decisions: (1) distribution of the ultimately approved rate change among customer classes; and (2) the rate components used to collect revenues from each customer class. The CCOS is only one piece of information to be considered in the distribution of the revenue increase among customer classes. Rate impact, non-cost considerations, promoting efficient behavior, and public policy are also relevant factors.

Q. IS RATE MODERATION NECESSARY FOR THE APPORTIONMENT OF REVENUE INCREASES AMONG CUSTOMER CLASSES IN THIS CASE?

A. Yes. Extreme variations in revenue-cost positions exist among the customer classes in this case. Furthermore, the COVID pandemic is an exceptional circumstance, principally due to stay at home orders, business closures, and an increase in work from home activities. The pandemic created aberrant usage patterns among the major rate classes during the 2020 test year. The Company recognizes that these facts justify cap/floor class revenue change limits.

Q. DOES THE COMPANY'S CURRENT CCOS STUDY PROVIDE DIVERGENT CONCLUSIONS REGARDING CLASS CROSS-SUBSIDIES COMPARED TO THE PRIOR CCOS STUDY IN DOCKET NO. 46831?

A. Yes. Some classes which in previous cases[37] were previously portrayed as highly subsidized are now shown as receiving subsidies, and vice versa. To some extent, the unusual effects of the COVID pandemic play a role in the change in class relationships. For some classes, this may be due to the inherent imprecision of CCOS studies, thereby causing subsidy positions to be a moving target. In the examples shown below, customer classes moved from severely overpriced (indicated as a revenue reduction) to severely overpriced (significant revenue increase indicated), and vice versa.[38] The indicated revenue increase in the current CCOS study is prior to the Company's capping proposal.

DIVERGENT RESULTS: 2017 VS. 2021 CCOS

	DOCKET 46831 Pct. Rev Incr.	CURRENT CCOS Pct. Rev Incr.
Irrigation	-3.9%	31.4%
General S.	7.8%	-8.9%
Military	-2.50%	13.4%
Cotton G.	-0.81%	33.5%
City/County	15.80%	-11.50%

Q. WHAT IS THE APPROPRIATE ROLE OF THE EMBEDDED CCOS STUDY RESULTS IN DETERMINING CLASS REVENUE INCREASES?

A. The CCOS provides useful information for developing the class revenue increases, but it should not be the sole consideration. Non-cost considerations are appropriate in mitigating pure CCOS results. This principle has been recognized in longstanding regulatory texts, such as Dr. James Bonbright's seminal *Principles of Public Utility*

[37] Docket Nos. 44941 and Docket 46831

[38] Carrasco at 17; Docket No. 46831, Schedule Q-1.

Rates.[39] From its earliest history, the Commission has recognized the principle that cost study results are subject to rate mitigation. In my experience, the Commission has applied class revenue increase caps ranging from 125% to 175% of the system average increase, with 150% as the most common cap.[40]

CCOS studies are imprecise instruments. The studies will allocate costs to a multiple decimal point level, but this may provide a false sense of security about the accuracy of the studies. This conclusion is based on two general reservations regarding embedded CCOS studies. First, some of the costs are classified and allocated on a disputable causal basis, and subjective judgment enters into the selection and development of allocation methods. The CCOS results may be quite sensitive to alternative classification or allocation decisions that are within the range of reasonable choices. As a result, it may be more appropriate to characterize the CCOS in the form of a range of acceptable rates of return instead of a single point estimate. Second, CCOS studies are a static snapshot of the dynamic relationship between supply and demand. Both costs and class usage characteristics will change over various time periods. For these reasons, some degree of judgment may be appropriate in applying the CCOS study to class revenue increases. "Cost based rates" are best viewed as representing a reasonable band around the CCOS results, rather than exact price points. Furthermore, CCOS studies that do not recognize the differences in risk associated with customer classes should be utilized cautiously.

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[39] James Bonbright, *Principles of Public Utility Rates*, Chapter 16, "Criteria for A Sound Rate Structure," (Columbia Press) (1961).

[40] The lower end adopted limit of 125% pertains to the decision in *Application of Gulf States Utilities Co.*, Docket No. 7195, with a lower 10% revenue increase constraint for lighting service. The most recent decision which adopted 175% as the gradualism limit was *Application of Texas Utilities Electric Co.*, Docket No. 11735.

Q. PLEASE DESCRIBE YOUR APPROACH TO RATE MODERATION, GIVEN DIVERGENT REVENUE REQUIREMENT POSITIONS IN THIS CASE.

A. I will present class revenue distribution recommendations based on the Company's requested base revenue increase, as well as the lower revenue requirement (and total revenue reduction) recommended by CEP witnesses.

Q. IS THE COMPANY'S APPROACH TO CAPPING CLASS REVENUE INCREASES ADEQUATE?

A. No. The Company's principal component is based on limiting the residential revenue increase to 150% of the Texas retail percentage increase. This percentage is higher than the residential revenue increase resulting from the CCOS with my recommended adjustments. Therefore, the revenue increase limitation should be reduced below 150%. In addition, applying this revenue limiter to other customer classes facing high percentage increase would be more equitable. The final component of the Company's class limiter is applied to classes with an indicated revenue decrease and multiplies the size of the rate reduction by 50%. However, this limitation is not well supported. In particular, how does the Company know that a revenue reduction of any size would be indicated in the absence of the extraordinary COVID impacts during the test year? As shown previously, the CCOS studies in Docket No. 49831 and the current case are not consistent in identifying classes that require a revenue reduction.

Q. PLEASE DESCRIBE THE PROCEDURE YOU APPLIED FOR MITIGATING CLASS REVENUE INCREASES UNDER THE COMPANY'S PROPOSAL.

A. My example is based on the Company's requested firm base revenue increase, but, for comparability, does not include the decrease in interruptible credits recommended in my testimony. The revenue distribution reflects two rate moderation tools: (1) Customer class revenue increases are capped at 140% of the system average percentage, and (2) No class receives a base revenue reduction so long as the total retail firm base revenues increase. In my view, given the circumstances in this case, the most equitable approach precludes a revenue reduction for any class when the overall retail system faces a significant revenue increase. Selected revenue reductions compound the severity of revenue increases confronting most customers. The revenue distribution based on the Company's proposed revenue requirement is shown on Schedule CJ-5.

Q. HAVE YOU PREPARED A REVENUE DISTRIBUTION BASED ON THE SYSTEM REVENUE REDUCTION RECOMMENDED BY CEP WITNESSES?

A. Yes. The revenue distribution is shown on Schedule CJ-6. My method is informed by the principle that no firm class should receive an increase when total Texas retail revenues are materially reduced. The moderation of results for classes with indicated increases is also justified by the inherent reliability issues caused by the test year in this case. Schedule CJ-6 is based on capping class revenue increases at zero, and allocating the remaining revenue reduction to classes in proportion to the percentage of reduction indicated by the CCOS study.

V. EPE'S INCREMENTAL GENERATION CAPACITY COST

Q. WHAT IS INCREMENTAL GENERATION CAPACITY COST?

A. Conceptually, this incremental cost represents the fixed generation costs which would be incurred in order to meet future increases in demand or resolve projected deficiencies in generation reserves. These incremental costs may also be referred to as avoided generation capacity cost, a term which focuses on actions that can be undertaken to avoid incurring future generation capacity cost. The concept is a measurement of forward-looking generation costs. Frequently the cost of a gas-fired combustion turbine (CT) plant is used as a proxy for the cost of peak demand, because such generation units can be installed relatively quickly, and the operational characteristics of a CT unit are ideal for meeting short duration peak loads. EPE's incremental generation capacity cost is based on the cost of installing a CT unit.

Q. WHAT IS THE IMPORTANCE OF INCREMENTAL CAPACITY COST TO EPE'S RATE DESIGN?

A. According to Mr. Carrasco's testimony, the Company uses its incremental generation capacity costs to inform various components of its rate design. For interruptible service, the Company uses incremental capacity cost to evaluate the pricing of interruptible demand charge credits. For time of use (TOU) and electric vehicle (EV) rates, incremental capacity costs are used to develop prices during peak periods. And, at least in general terms, the costs may inform the design of peak and off-peak prices, such as seasonal rate differentials.

Q. DO YOU HAVE CONCERNS ABOUT THE INCREMENTAL GENERATION CAPACITY COSTS USED BY EPE FOR ITS RATE DESIGN ANALYSES?

A. Yes. In my opinion, EPE's incremental costs *overstate* the cost of avoiding or delaying future generation capacity costs. The effect is to overstate the benefit of peak demand reduction. EPE's develops its incremental generation capacity cost based the cost of

Rio Grande 9, which is a CT installed in 2013.[41] According to the U.S. Energy Information Administration (EIA), the construction costs of most types of generation units declined between 2013 and 2017.[42] The cost of newly installed gas generation declined by 28% compared to 2013.[43] Moreover, more recent points of reference indicate that a CT cost lower than EPE's RG-9 would be a more reasonable measure of incremental generation capacity cost.

Q. PLEASE DESCRIBE HOW THE COMPANY'S INCREMENTAL GENERATION CAPACITY COSTS COMPARE TO OTHER BENCHMARKS OF INCREMENTAL CAPACITY COSTS.

A. Based on RG-9, the Company uses $113.81 per kW-year to measure incremental capacity cost.[44] Schedule CJ-7 provides my calculation of incremental generation capacity cost based on U.S. EIA estimates for installing a CT in the El Paso region in 2022.[45] EIA *Energy Outlook* cost estimates for different types of generation technologies are widely used to develop capacity costs, and this source is referenced in the definition of avoided capacity cost used by the energy efficiency rule.[46] Schedule CJ-7 uses EIA's CT costs for the WECC-Southwest regions, and the levelized fixed charge rate developed by EPE. The incremental generation capacity cost estimate is $59 per kW-year. The PUC's energy efficiency rule requires an annual determination

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[41] *See*, WP-Q-7 (a).
[42] EIA, *Today In Energy*, July 5, 2017, "Construction Costs for Most Power Plant Types Have Declined in Recent Years." https://www.eia.gov/todayinenergy/detail.php?id=31912
[43] Ibidem.
[44] WP/Q-7(a), Sheet: RG-9 Avoided Cost Calc.
[45] U.S. Energy Information Administration, Assumptions *to Annual Energy Outlook 2021,* February 2021, Tables 4 and 5.

[46] 16 Texas Administrative Code (TAC) § 25.181(d)(2)(A)(ii). The rule uses the EIA CT estimate in a simplified bracket procedure, which may tend to provide a high estimate of avoided cost.

of avoided generation costs applicable to the ERCOT region. As shown on Schedule CJ-8, the PUC determined an avoided capacity cost of $80 per kW-year for 2021.

Q. PLEASE SUMMARIZE THE COMPARISON OF INCREMENTAL CAPACITY COSTS.

A. A comparison of EPE's incremental generation capacity costs and the two benchmarks for generation capacity is shown below. Notably EPE's estimate is considerably higher than the two recent estimates.

Incremental Generation Capacity Cost

Per EPE Schedule Q-7	**$113 / kW**
2021 U.S. EIA	**$59 / kW**
PUC 2021 EEP Rule	**$80 / kW**

Q. PLEASE STATE ANY ADDITIONAL REASONS THAT THE COMPANY'S INCREMENTAL COST ESTIMATE IS OVERSTATED?

A. Yes. The Company's $113 per kW incremental capacity cost includes approximately $20 per kW for RG-9 production O&M expense.[47] The calculation includes both variable and fixed production O&M expense; only fixed O&M should be included in avoided capacity cost. As a result, the expense may be 73% too high ($5.36 per kW), which would reduce the Company's incremental cost estimate below $100 per kW.[48] The Company's RG-9 production O&M expense amount in this case is 166% higher than the $7.46 kW RG-9 production expense utilized for incremental capacity cost in

[47] WP/Q-7(a), Sheet: RG-9 Avoided Cost Calc.

[48] See, Schedule P-04. 73% of Steam Generation Production Non-Fuel expense is energy-related (i.e., variable). 27% is demand-related, which more closely corresponds to fixed generation O&M expense. Note that EIA estimates the CT fixed O&M at $7.04 / kW and variable O&M at $4.52/ kW.

the previous rate case.[49] Furthermore, actual avoided capacity cost may be lower than the theoretical cost of installing a new CT. If market purchased power is available at a lower cost, electric utilities frequently will purchase capacity rather than build new capacity. Furthermore, the deferral of installing new capacity—which is often a more realistic characterization of demand reduction—results in a lower avoided capacity than the levelized fixed charge rate used by EPE would indicate.

Q. WHAT IS THE IMPLICATION OF YOUR REVIEW OF EPE'S INCREMENTAL GENERATION CAPACITY COST?

A. The Company's assessment of future production capacity cost probably overstates avoided cost. As a result, EPE's rate design outlook may place excessive emphasis on peak demand reduction. Consideration of tempering the peak adders and similar components requested in TOU and EV rates may be warranted. Furthermore, the Company's measurement of the system benefits from the interruptible tariff conceals the full magnitude of underpricing interruptible demand charges. Additionally, as I will discuss in my recommendation regarding changes to the summer/winter differential, this issue may have implications regarding the reasonableness of the Company's proposed seasonal rates.

VI. INTERRUPTIBLE SERVICE

Q. PLEASE DESCRIBE NOTICED INTERRUPTIBLE SERVICE.

A. EPE's Interruptible Service (Rate 38) is utilized by some large power customers who agree to accept interruptions in exchange for a discount or credit applied to the monthly

[49] Docket No. 46831, WP/Q-7 (a) Sheet: RG9 Avoided Cost Calc.

demand charge. The customer is required to interrupt load on 30 minutes notice. The incentive (in the form of a credit) provided to the interruptible customer should be valued based on the avoided cost of peak generation capacity, similar to an energy efficiency program. The size of the interruptible credit should not be higher than avoided generation capacity cost. If the credit exceeds avoided capacity cost, the interruptible program is not cost justified and could be treated as a discounted rate pursuant to Sec. 36.007 PURA. As discussed previously, EPE quantifies avoided generation capacity based on the levelized cost associated with Rio Grande 9, a combustion turbine peak unit on its system. The noticed interruptible rate is currently closed to new customers. However, the Company proposes to open the rate to new customers, up to a maximum of 28 MW of new interruptible load.

Q. WHAT IS EPE'S RECOMMENDATION WITH RESPECT TO THE INTERRUPTIBLE RATE?

A. Although Mr. Carrasco's testimony acknowledges that the interruptible credit exceeds avoided cost and that the credit should be moved toward incremental capacity cost, the proposed increase in Rate 38 base revenues is $326,000—or 7.8%, which is less than the proposed percentage increase for eight other classes. The Company achieves this result by applying a 45.5% discount to the cost-based interruptible credit based on the estimate of incremental generation capacity. The Company calls this discount a "rate moderation adjustment."[50]

[50] WP/Q-7(a), Sheet: "Rate 38 Int Credit."

Q. IS THE 45.5% DISCOUNT OF COST-BASED DEMAND CREDITS AN UNDERSTATEMENT OF THE TRUE DISCOUNT?

A. Yes. As I discussed in Sec. V, the Company's incremental generation capacity cost estimate exceeds the avoided capacity cost derived in the energy efficiency rule and the most recent EIA estimate of CT costs by 40% - 88%. This suggests that the discount of cost-based demand credits is 106% - 175% rather than 45%.[51] By relying on a "high" avoided capacity cost, the Company conceals the full extent of the discount applied to cost-based credits.

Q. PLEASE SHOW THE INTERRUPTIBLE DEMAND CHARGE PERCENTAGE WITH THE COMPANY'S PROPOSAL AND AT DIFFERENT MEASURES OF AVOIDED COST.

A. The comparison below displays the interruptible demand charge (transmission voltage) based on the Company's proposal, and at EPE's measure of avoided capacity cost. The comparison also shows the interruptible demand charge based on measures of avoided cost approximating the current EIA CT cost ($60) and the PUC energy efficiency program avoided cost ($80). The resulting percentage of firm demand charge illustrates the reduction to the standard demand rates.[52]

Interruptible Demand Charge

	Firm	Interruptible	% Firm
Proposed	18.28	4.14	23%
At Cost Per EPE	18.28	8.56	47%

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[51] For EIA estimate: [($166 per kW-yr. / $60 per kW-yr.) – 1]. For EE rule avoided cost: [($166 per kW-yr. / $80 per kW-yr.) – 1].
[52] WP/Q-7 (a), sheets: "Rate 38 Int Credit" and "Rate 38 Demand Rate."

$80 avoided cost	18.28	11.45	63%
$60 avoided cost	18.28	13.12	72%

Note: Transmission Voltage

Q. DO YOU AGREE WITH EPE'S PROPOSED PRICING OF INTERRUPTIBLE SERVICE?

A. No. The cost of the interruptible credit greatly exceeds benefits, as measured by avoided cost. The Company should bring the interruptible credit in closer alignment with avoided capacity cost. The interruptible class is not allocated costs in the CCOS study, which has the effect of increasing allocable costs for other customer classes. As compensation for this treatment, the noticed interruptible base revenues are allocated as a reduction to the allocable costs of other classes. To the extent that the interruptible credit is excessive, less interruptible revenue is available to reduce rates paid by the firm classes. Therefore, the Company's failure to address the excessive discount for interruptible service causes all firm classes to pay higher costs.

Q. IS THE COMPANY'S PROPOSAL A COST-EFFECTIVE APPROACH TO ADDRESSING RESERVE MARGIN DEFICIENCIES?

A. No. If the credit exceeds avoided capacity cost, the Company can acquire generating reserves at a lower cost than the interruptible program. Furthermore, it means that the interruptible rate option is not on a level playing field with other demand side management tools. The energy efficiency program pays incentives to customers to reduce future demand and avoid future capacity cost, similar to the interruptible rate.

But the interruptible rate would pay the customer $166 per kW-year compared to the EEP's incentive maximum of $80 per kW-year.

Q. HAS THE COMMISSION PREVIOUSLY ADDRESSED INTERRUPTIBLE TARIFFS WHICH ARE UNDER PRICED?

A. Yes. As this century began, high firm rates caused some Texas electric utilities to use interruptible rates as load retention tariffs rather than cost-based load management tools. In response, the Commission found interruptible rates to be underpriced and oversubscribed, and ordered remediation plans, including transitions to higher interruptible rates, closing the rates to new customers, and a deadline for redesigning the interruptible credits to meet market-based avoided costs.[53]

Q. WHAT IS YOUR RECOMMENDATION?

A. My recommendation is to increase the Company's proposed interruptible base revenue increase for existing customers by $1.388 million. This is based on reducing the Company's rate moderation discount from 46% to 30%. Although the interruptible credits should be set consistent with avoided cost, my recommendation recognizes that the magnitude of such an increase should be phased in. The interruptible credits for transmission and primary voltage customers would be $13.10 and $12.63 per kW-mo., respectively, approximately a 12% reduction in the size of EPE's proposed credits. The decrease in the credit is allocated as a cost offset to all firm classes. I also recommend that the Commission order the Company to prepare a study of current avoided capacity

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[53] *See, Application of Central Power & Light Company for Authority to Change Rates*, Docket No. 14965 (Mar. 31, 1977) and *Application of Entergy Gulf States Utilities Company for Authority to Change Rates*, Docket No. 7195 (May 16, 1988).

costs and develop a plan for bringing the interruptible rate for existing customers into alignment with those costs in future rate case.

Q. WHAT IS YOUR POSITION REGARDING THE COMPANY'S PROPOSAL TO OPEN THE INTERRUPTIBLE TARIFF TO NEW CUSTOMERS?

A. I do not agree with EPE's request to open the tariff to new customers, *unless* the interruptible demand charge credits for new customers are set equal to the avoided generation capacity cost. It is unreasonable to open the tariff for new customers to take subsidized service. Furthermore, by setting a cost-based rate for new interruptible customers, the Company can gather information on the willingness of industrial customers to accept interruptible service based on avoided cost.

Q. WHAT IS THE APPROPRIATE TREATMENT IF THE INTERRUPTIBLE RATE WAS DETERMINED TO BE A DISCOUNTED RATE PURSUANT TO SEC. 36.007 PURA?

A. The allocable costs of serving discounted rate customers cannot be borne by other customers of the utility.[54] To the extent that the interruptible discount is priced for load retention rather than avoided cost, the Commission can require the utility to absorb the shortfall.

[54] PURA 36.007(d).

VII. RATE DESIGN

A. Residential Rate Structure

1. Customer Charge

Q. HOW HAS THE COMPANY PROPOSED TO INCREASE THE RESIDENTIAL CUSTOMER CHARGE?

A. EPE proposes to increase the residential monthly customer charge from $8.25 to $10.54. The 28% percent proposed increase in the fixed customer charge is excessive, with a percentage increase nearly three times the overall percentage change in revenues. The proposed increase follows a cumulative 58% customer charge increase approved in Docket Nos. 44941 and 46831.

Q. WOULD EPE'S PROPOSED RESIDENTIAL CUSTOMER CHARGE BE THE HIGHEST AMONG INVESTOR-OWNED ELECTRIC UTILITIES IN TEXAS?

A. Yes. EPE's proposed residential customer charge of $10.54 is higher than any of the other Texas investor-owned electric utilities. The average monthly customer charge for the seven investor-owned electric utilities (excluding EPE) is $6.98.[55] *See*, Schedule CJ-9. The Company's proposal would move EPE's residential customer from 18% above the statewide average to 51% higher than the statewide average.

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[55] For unbundled electric utilities, the customer charge is the sum of the meter charge and the customer service charge.

Q. DOES MR. CARRASCO'S TESTIMONY ATTEMPT TO JUSTIFY THE PROPOSED CUSTOMER RELATIVE TO OTHER CUSTOMER CHARGE RATES IN TEXAS?

A. Yes. He asserts that EPE's proposed customer charge is within the "zone of reasonableness" by comparing the rate to the three other bundled electric utilities in Texas. However, his comparison ignores the four investor-owned transmission-distribution electric utilities in Texas. I disagree with excluding these electric utilities from a review of average customer charges in Texas. The difference between unbundled and bundled electric utilities in Texas is that the generation function is not part of the unbundled TDUs. But the generation function does not include customer costs and will not affect the customer charge. The customer charge is functionally the same for TDUs and bundled electric utilities. In a discovery response, Mr. Carrasco contends that EPE's customer charge should not be compared to ERCOT TDUs because the unbundled electric utilities do not have a "direct relationship" with customers.[56] This is not material to the comparison of customer charges. ERCOT TDUs operate call centers, just like EPE. End use customers contact the TDU to report outages and safety problems. Even if EPE's call center handles some billing calls that the TDUs do not, these contacts cannot explain the difference between EPE's monthly customer charge and ERCOT TDUs' fixed monthly charges. EPE's total call center expense contributes 88 cents per month to the residential customer charge.[57] EPE's customer charge is $3.14 higher than the average ERCOT TDU customer charge.

[56] EPE Response to CEP 9-39.

[57] Response to EPE Response to CEP 14-14; 0.9 allocation factor X $3.618 million call center expense divided by 3.665 million billing units.

Q. WHAT IS THE POLICY OBJECTIVE OF PRICING THE FIXED MONTHLY CUSTOMER CHARGE?

A. The customer charge should only recover costs that vary directly with the number of customers. [58] Generally, the costs that vary directly with customer count consist of meters, service lines, meter reading, and customer billing. Although the Company asserts that the customer unit cost in the CCOS justifies the significant customer charge increase, the study includes costs in the customer unit price that are not directly associated with customers, and do not vary with the number of customers. The CCOS's customer unit cost includes a portion of general overhead costs, such as A&G expense and general plant, which do not vary with changes in the number of customers.

Q. HAVE YOU CALCULATED A RESIDENTIAL CUSTOMER CHARGE FOR EPE BASED ONLY ON COSTS WHICH VARY WITH TO THE NUMBER OF CUSTOMERS?

A. Yes. My estimate of the residential customer charge directly related to the number of customers results is $5.06. Since the existing customer charge is $8.25, the current customer charge is more than compensatory. The calculation includes O&M expense for meters, services, meter reading, and customer accounting, and also encompasses the return, depreciation, and carrying charges associated with meter and service investment, minus credits for customer deposits and related accumulated deferred federal income taxes ("ADFIT").[59] My calculation is consistent with the historic

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[58] See, Docket No. 22344, Generic Issues Associated With Applications For Approval Of Unbundled Cost Of Service, Order No. 40 at 6, Interim Order Establishing Generic Customer Classification and Rate Design, "Specifically, the customer charge shall be comprised of costs that vary by customer such as metering, billing and customer service."

[59] My calculation also includes a prorated portion of pensions and benefits (Account 926) associated with the O&M expense in the customer charge.

Commission practice for evaluating the customer charge level of bundled electric utilities.[60] The calculation is set out on Schedule CJ-11. In the last EPE rate case in which the residential customer charge was litigated, the Staff's customer charge study produced a benchmark minimum cost of $1.35,[61] and the Staff's recommended $4.50 customer charge was adopted.[62] To the extent that the current customer charge exceeds the direct customer costs, the existing monthly fixed rate recovers direct customer costs plus a contribution to utility common costs.

Q. DOES THE COMPANY INCLUDE UNCOLLECTIBLE EXPENSE IN THE RESIDENTIAL CUSTOMER CHARGE?

A. Yes. The Company recovers $1.17 million of the $1.7 million total Texas uncollectible expense through the residential customer charge.[63] I disagree with the notion that the fixed customer charge is the appropriate recovery mechanism for uncollectible costs. The amount of uncollectible expense is determined by the size of customer bills which are unpaid and does not vary directly with the number of customers. The Company dumped uncollectibles into the customer charge because the expense is recorded in customer accounting; however, the act of recording the expense in a customer account does not mean that the cost varies directly with number of customers.[64] Moreover, residential uncollectibles are overwhelmingly associated with unpaid variable charges,

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[60] *See* for example *Application of Houston Lighting & Power Company*, Docket No. 8425, Examiners' Report at 264, 16 P.U.C. Bull. 2199, 2488 (June 20, 1990).

[61] *Application of El Paso Electric Co for Authority to Change Rates*, Docket No. 9945, Examiners' Report at 330, 18 P.U.C. Bull. 14, 358 (Sept. 16, 1991).

[62] Docket No. 9945, Examiners' Report at 371, 18 P.U.C. Bull. 399; Docket No. 9945, Final Order at 1, 18 P.U.C. Bull. 466 (Nov. 12, 1991).

[63] EPE Response to CEP Request No. 9-18, Attachment 1.

[64] Note that the NARUC Electric Utility Cost Allocation Manual (CAM) specifically excludes uncollectibles from the customer classification. CAM at 103.

and variable rates comprise 89% of residential non-fuel revenues. And, most likely, a higher percentage of uncollectible expense is caused by unpaid variable charges.[65] The Company's inclusion of the full residential uncollectible expense demonstrates how indirect costs are loaded into the Company's proposed customer charge.

Q. WHAT ARE THE POLICY REASONS FOR ENSURING THE RESIDENTIAL CUSTOMER CHARGE IS NOT EXCESSIVE?

A. An excessive customer charge can distort appropriate price signals for residential customers. The dominant economic function of a customer charge is to ration access to the utility system. That objective conflicts with the policy basis for regulating monopolies and is counter to the concept of electricity as an essential service. With the exception of its access rationing role, the customer charge provides no meaningful price signal that is relevant to resource allocation. Because the electric utility's cost structure is dominated by costs that vary with changes in demand and energy usage, the usage-sensitive rate is the primary source of meaningful price signals. A lower customer charge ensures a greater proportion of costs are recovered through a usage-sensitive price (i.e., kWh charges). That result is more consistent with energy conservation goals and provides pricing policies appropriate for consumption of finite natural resources. In addition, a policy that minimizes the customer charge is more equitable to low-usage residential customers.

Q. WHAT IS THE EFFECT OF AN EXCESSIVE CUSTOMER CHARGE ON ENERGY EFFICIENCY?

[65] High bills, caused by high usage, are more likely to be unpaid.

A. A high customer charge tends to inhibit energy conservation. Minimizing the customer charge provides the ratepayers with a greater ability to control their bill on the basis of usage. At a time when electric utilities spend millions of dollars on energy efficiency programs, maintaining the fixed monthly charge at a low level is a relatively inexpensive action for achieving reduced energy consumption. But the long-term tendency for the customer charge to creep upward can inhibit the attractiveness of energy savings measures, because a larger portion of the rate structure is invariant with energy usage. This can adversely affect the payback period and net bill savings available to customers who purchase high efficiency appliances.

Q. PLEASE COMMENT ON EPE WITNESS MR. CARRASCO'S ASSERTION THAT THE CUSTOMER CHARGE PROPOSAL IS INTENDED TO INCREASE THE ACCURACY OF PRICE SIGNALS.

A. Since the end result of EPE's proposal is to place a greater reliance on fixed charges and reduce the percentage of cost recovered through variable rates, Mr. Carrasco's claim seems to imply that the current customer charge provides an excessive price signal for energy efficiency. Increasing the customer charge provides no direct price signal related to electricity consumption, but it indirectly reduces the price signal for power consumption by shifting costs from the usage rate to the fixed charge. Despite Mr. Carrasco's statement that "to the extent possible" EPE' rate design "encourages energy conservation," his claim that the higher customer charge will provide "more accurate price signals" indicates concern that EPE's customers may undertake energy efficiency measures which are not cost-effective. However, he has not provided any evidence that the Company's customers are undertaking energy efficiency measures that are not cost justified. The barriers which inhibit cost-effective energy efficiency are a more significant problem than excessive proliferation of energy efficiency actions. Given household budget limitations, customers may require unrealistic payback periods in order to undertake cost-effective energy efficiency measures. All else equal, a lower customer charge will increase the price signal for energy efficiency and reduce the payback period for such measures, thereby increasing the penetration of cost-effective energy efficiency in the marketplace.

Q. WHAT IS YOUR RECOMMENDATION?

A. Given my customer charge analysis, the customer charge should remain at the current $8.25 monthly rate. As a maximum, I recommend limiting any customer charge increase by a percentage no higher than the percentage increase in total retail base revenues allowed by the Commission. Assuming adoption of a revenue change close to City's recommendation, little or no change in the customer charge is justified.

2. <u>Seasonal Differential and Summer Block Rate</u>

Q. WHAT IS THE COMPANY'S PROPOSED RESIDENTIAL RATE STRUCTURE?

A. First, for determining seasonal rate differences, EPE proposes to define the summer as four months instead of the current six months. The Company's intent is to concentrate higher rates on the four hottest months. EPE proposes to continue a flat winter energy charge and two block rates in the summer. For the first block rate (up to 600 kWh) the Company proposes a two cent higher rate than the winter rate, compared to the current one cent differential. This first summer block would be one cent higher than the second summer block (>600 kWh), compared to the current one-half cent differential. The

Company's intent is to increase the peak demand price incentive. The gap between winter and summer prices would be increased, and prices for customers with higher kWh billing in summer would also be increased.

Q. HAS THE COMPANY PROVIDED ANALYSES TO SUPPORT THIS SIGNIFICANT CHANGE IN SUMMER PRICING?

A. No. The proposed pricing change for residential summer rates "was a management decision not based on any calculations."[66] Furthermore, the Company "did not prepare any customer impact analyses that separately identifies or evaluates the impact of EPE's proposed change in the definition of summer season, the increase in the seasonal price differential, and increase in the price differential between the first and second energy blocks for summer…"[67]

Q. ARE YOU CONCERNED ABOUT THE SUMMER BILL IMPACTS OF THE COMPANY'S PROPOSED CHANGES IN RESIDENTIAL RATE DIFFERENTIALS?

A. Yes. The magnitude of the rate changes is significant enough to create the potential for public backlash against the changes in monthly summer bills. This tendency is intensified by the two-block rate structure. An unusually hot summer could move lower usage customers, accustomed to bills below 600 kWh, into the higher usage block, resulting in a greater increase in bills above the customers' usual expectations. The differentials may also increase the potential for revenue instability, with the Company potentially benefitting from excess revenues during particularly hot

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[66] EPE Response to OPUC Request 7-7.
[67] EPE Response to OPUC Request 7-8.

summers. These considerations are relevant to developing a sound rate structure.[68] I calculated the bill increase impacts at different summer usage levels, below. The comparison is based on the Company's proposed customer charge and summer non-fuel energy rates. The annual percentage revenue change for the residential class is shown as a contrast.

Summer kWh	Current	Proposed	Difference	Percentage
600	$67.56	$81.50	$13.94	20.636%
1000	$109.10	$132.81	$23.71	21.732%
1200	$129.87	$158.46	$28.59	22.017%
1500	$161.03	$196.95	$35.92	22.307%
2000	$212.95	$261.08	$48.13	22.602%
Residential Average Percentage Rev Increase				**13.59%**

Q. IS IT POSSIBLE TO PLACE EXCESSIVE EMPHASIS ON SUMMER DEMANDS?

A. Yes. Although EPE annual peak hour demand is likely to occur in the summer, this does not mean that there should be no concern regarding non-summer demands. Both supply and demand are relevant to the potential for reserve margin deficiencies. The disastrous consequences of winter storm Uri on Texas electric utilities demonstrates that emergency conditions can arise in the winter.[69] Presumably, the Company's previous six-month definition of summer was intended to encompass the shoulder months when generation maintenance causes reserve margins to decline.

Q. ARE YOU AWARE OF ANY FAIRNESS ISSUES RAISED BY THE INCREASE IN THE SUMMER BLOCK DIFFERENTIAL?

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[68] James Bonbright, *Principles of Public Utility Rates*, 291 (Columbia Press) (1961).

[69] EPE experienced a negative generation reserve margin on Feb. 14, 2021. *See*, EPE Response to CEP 9-23, Attachment 1.

A. Yes. The Company proposes to double the differential between the first and second summer block. The rate for the second block would be three cents higher than the winter rate, compared to the current one and a half cents. The summer cooling appliances will affect whether customers consume energy in the second block, above 600 kWh. EPE previously promoted efforts to shift residential customers from evaporative cooling to refrigerated air conditioning (which is more energy intensive) by offering a water conservation discount. The increase in the second block rate adversely affects ratepayers who recently invested in durable energy consuming devices (such as refrigerated air conditioning) and, therefore, have fewer options to respond to the block's price signal. Residential customers who accepted the Company's proposal to change air cooling appliances may view the new rate structure as unfair. The Company's two summer block structure provides a reasonable incentive for energy efficiency. But fairness and rate gradualism considerations should temper any increase in the block rate differentials.

Q. WHAT IS YOUR RECOMMENDATION REGARDING THE COMPANY'S PROPOSED SUMMER RATE STRUCTURE?

A. There are two options. First, all of the Company's proposed changes, including the summer month definition, the seasonal differential, and the summer block differential, could be rejected because the Company has not produced sufficient analysis to support its position. The Company's current six-month summer rate period and the current rate differentials would continue to apply. Second, in the alternative, the Company's proposed changes could be tempered to produce a lesser customer impact. In my view, the first option, the *status quo* option is preferred, because it recognizes the Company's burden of proof.But an equally reasonable position is to develop a less severe change in the summer rate structure.

Q. HAVE YOU PREPARED AN ALTERNATIVE TO THE COMPANY'S PROPOSAL?

A. Yes. I revised the Company's proposal, accepting the four-month summer definition but reducing the magnitude of changes to the rate differentials. The differential between the winter rate and first summer block rate is one cent. The differential between the first and second summer block is 0.7 cents. A comparison of the Company's proposed residential energy rates and the revised residential energy rates is shown on Schedule CJ-11. The resulting overall summer/winter differential is consistent with pricing the differential based on the 2021 EIA CT capacity cost as a representation of incremental cost (Schedule CJ-7).[70] The comparison below shows the percentage increase in base rates under the revised proposal versus the Company's summer rate structure. This indicates a significant moderation of the percent increase in summer rates at various usage levels.

Revised Differentials

Summer kWh	*Increase*	*% Incr.*	*EPE incr. %*
600	$11.31	16.7%	20.6%
1000	$18.12	16.6%	21.7%
1200	$21.53	16.6%	22.0%
1500	$26.63	16.5%	22.3%
2000	$35.15	16.5%	22.6%

[70] For this calculation, I assumed that 60% of incremental capacity cost is recovered during peak periods, as the Company has proposed in its Time of Use rates. Pricing the differential on the basis of that incremental cost results in a 1.25 cent average seasonal differential compared to 1.36 cents with my alternative proposal. The Company's proposed average seasonal differential is 2.5 cents.

Q. BASED ON THE CITY'S CASE, DOES YOUR CUSTOMER CHARGE PROPOSAL REQUIRE A CHANGE IN THE BLOCK ENERGY RATES?

A. No. My recommendation is to maintain the customer charge at its current level. The City's case indicates that residential base rates should be decreased. The residential revenue decrease should be applied on an equal percentage basis to the winter and summer rates and to the two summer energy blocks.

B. <u>Time of Day Rates (TOD)</u>

Q. DID EPE RE-DESIGN THE PRICING FOR MOST OF ITS TOD RATE OPTIONS?

A. Yes. The Company is utilizing its incremental generation capacity cost, based on Rio Grande Unit 9, to establish peak time of day prices. Most of the TOD pricing programs are optional. But the Company is expanding mandatory TOD programs to encompass a larger number of customers in the General Service class (new customers >200 kW). The Company appears to be positioning its tariffs for potential mandatory TOD pricing for most customers after 2025, when the Company expects to install digital meters.

Q. DO YOU HAVE ANY CONCERNS ABOUT PROPOSED TOD PRICES?

A. Yes. As stated in Sec. V, the Company's incremental generation capacity cost, based on Rio Grande Unit 9, overstates EPE's avoided cost. Because the TOD peak prices rely upon this representation of incremental capacity cost, the peak prices are potentially too high. Mr. Carrasco's testimony admits that EPE's peak-to-off peak price ratio is "in fact much higher" than the median for electric utility TOD rate programs.[71]

[71] Carrasco at 38. Cites a median 2.71 ratio among electric utilities, compared to EPE's proposed ratio of 3.34.

As discussed in Sec. V, the Commission should consider tempering the TOD rate impact.

Q. WHAT IS YOUR RECOMMENDATION FOR TOD RATES?

A. My recommendation is to reduce the Company's $113/kW incremental generation capacity cost to $100/kW in each of the TOD calculations. Given that my analysis of avoided capacity cost would support a larger reduction, this is a relatively moderate change. As discussed previously, the Company's non-fuel production O&M expense for incremental capacity did not distinguish between fixed and variable O&M. A reasonable reduction in the expense would reduce the Company's incremental capacity cost value to $97/kW. The annual revenue effect of this change does not appear to be significant, but it could reduce the bill impact on TOD customers who have difficulty reducing usage in the peak hours. I should also note that tempering the peak rate impact could enhance customer acceptance of the TOD option.

Q. DO YOU HAVE APPREHENSION REGARDING THE COMPANY'S PROPOSAL TO EXPAND THE SCOPE OF MANDATORY TOD RATES IN THE GENERAL SERVICE CLASS.

A. Yes. General Service is the rate class applicable to customers with loads between 15 kW and 600 kW. Currently the Company requires TOD for new customers sized 400 kW or larger. In this case, the Company seeks to make TOD mandatory for new customers over 200 kW in size. At the largest size, we assume that the customers are sophisticated enough to respond to, and analyze, TOD rates. However, the lower 200 kW threshold will encompass new applications from more numerous medium size businesses. The General Service class is generally the most diverse class in terms of end uses and processes for electric usage. Some new General Service customers may have limited or even no ability to reduce usage during peak hours. For some of these customers, avoiding peak hour charges may require changes to business models or purchases of different energy using equipment, which may require lengthier time to respond to price signals. The Company's proposal allows mandatory TOU customers to switch to the standard tariff after 12 months. However, if the rates are excessive for the new customer, requiring the customer to pay the TOD rate for 12 months could be onerous. The Commission should mitigate the potential for unexpected rate shock to materialize among new General Service customers.

Q. WHAT IS YOUR RECOMMENDATION REGARDING THE EXPANSION OF THE RATE 24 MANDATORY TOD SCHEDULE FOR NEW CUSTOMERS?

A. I suggest two changes. First, a more gradual expansion of the threshold—changing the current 400 kW threshold for new customers to 300 kW, instead of 200 kW as proposed by the Company. Secondly, I recommend that new customers who are subject to mandatory TOD should be permitted to change to the standard rate schedule after six months on TOD, instead of 12 months as proposed by the Company.

VIII. RATE CASE EXPENSE

Q. WHAT SERVICES HAVE YOU PROVIDED TO THE CITY OF EL PASO IN THIS CASE?

A. Through my business name, CJ Energy Consulting, I have provided the following services to the City of El Paso to date: 1) review and analysis of EPE's direct testimony; 2) preparation of discovery; 3) analysis EPE's discovery responses, 4) review of past testimony and orders addressing issues in this case, 5) identification and analysis of issues; and 6) preparation of direct testimony.

Q. WHAT ARE THE TOTAL CHARGES INCURRED BY CJ ENERGY CONSULTING FOR SERVICES PROVIDED TO CITY OF EL PASO IN THIS CASE?

A. CJ Energy Consulting has incurred total charges of $12,804 for services it has provided to the City of El Paso through September 30, 2021.

Q. ARE THE HOURLY RATES CHARGED TO CITY OF EL PASO BY CJ ENERGY CONSULTING FOR THIS CASE REASONABLE AND CONSISTENT WITH THE FEES CHARGED BY OTHER FIRMS FOR SIMILAR CONSULTING SERVICES?

A. Yes. My hourly rate of $220 for services provided to City of El Paso is reasonable when compared to the hourly rates charged by other regulatory consultants with similar experience, based on my personal knowledge of rates charged in other proceedings. The hourly rate charged for this project is equal to or less than the hourly rates charged by CJ Energy Consulting to other clients for similar services for contracts entered into during the time period contemporaneous with this proceeding.

Q. HAVE THE SERVICES PERFORMED BY CJ ENERGY CONSULTING FOR THE CITY OF EL PASO IN THIS PROCEEDING BEEN PROVIDED IN A PROFESSIONAL, TIMELY, AND EFFICIENT MANNER?

A. Yes. The services provided to the City of El Paso by CJ Energy Consulting are detailed on a monthly invoice, which includes a description of the services performed, and the number of hours charged in each day. The amounts charged for such services are reasonable, the calculation of the charges is correct, and there has been no double-billing of any charges. All work performed was conducted in a timely and efficient manner, and is relevant and necessary to address issues identified by CJ Energy Consulting in this the proceeding.

Q. HAS CJ ENERGY CONSULTING CHARGED 12 OR MORE HOURS IN ANY ONE DAY ON THIS PROJECT?

A. No.

Q. HAS CJ ENERGY CONSULTING CHARGED ANY AMOUNTS FOR TRAVEL, LODGING, MEALS, OR OTHER EXPENSES INCURRED DIRECTLY FOR THIS PROJECT?

A. No

Q. WHAT ARE THE ESTIMATED REMAINING CHARGES FOR CJ ENERGY CONSULTING TO COMPLETE THIS CASE?

A. I estimate that CJ Energy Consulting will incur an additional $24,196 for services provided to the City of El Paso after September 30, 2021, including: 1) completion of analysis of issues; 2) preparation of direct testimony; 3) review of direct testimony filed by other parties; 4) Preparation of Cross-rebuttal testimony 5) review of EPE's rebuttal testimony; 6) assistance with settlement negotiations; 7) assistance with development and support of cross examination; 8) preparation for testifying, 9) attendance and submittal of testimony at the hearing; and 10) assistance with briefs and any appeals.

Q. DOES THIS CONCLUDE YOUR TESTIMONY AT THIS TIME?

A. Yes.

SUMMARY OF QUALIFICATIONS

CLARENCE JOHNSON

EDUCATION

Bachelor of Science, Political Science, University of Houston.

Master of Arts, College of Social Science (Interdisciplinary/Urban Studies), University of Houston.

EXPERIENCE

Mr. Johnson has more than 35 years experience as an expert witness and analyst related to electric and telecommunications utility issues.

CURRENT EMPLOYMENT

Mr. Johnson currently provides professional consulting and analytical analyses regarding regulatory and public policies related to public utilities and the energy industry.

PREVIOUS EMPLOYMENT 1983-2008

From September 1983 to June 2008, Mr. Johnson was a Regulatory Analyst for the Office of Public Utility Counsel. He was the professional staff person with primary responsibility for advising the Public Counsel on economic and regulatory policy issues. His responsibilities included: presenting expert testimony on regulatory matters; research related to rate filings of regulated public utilities; acting as a non-testifying expert and advising attorneys in cross-examination of witnesses and development of trial exhibits for utility regulatory proceedings; analyzing policies and practices for regulating public utilities; and preparing comments on proposed Public Utility Commission rules; assisting financial and economic staff in the development and preparation of testimony; providing expert testimony on selected issues; preparation of reports to the Legislature regarding the utility regulatory process.

EMPLOYMENT BEFORE 1983

During the period 1977 to 1983, Mr. Johnson extensively engaged in analysis and supervision of public interest advocacy programs. He directed two non-profit corporations involved in public policy research from 1978 to 1980 and 1982 to 1983, respectively; responsibilities included overall management of the corporations, negotiation and management of grants and contracts, supervision of research activities, and presentations of research findings to legislative and administrative governmental entities. From 1980 to 1982, he also performed policy analysis and substantive research on the impact of governmental policies for two publicly-funded entities. His responsibilities for the statewide support center for legal services programs in Texas assessed the effect of federal and state regulatory changes upon indigent clients. As an analyst for the Texas State Senate's Natural Resources

Committee, Mr. Johnson was responsible for research related to low-level radioactive waste disposal and low-head hydropower, and the committee's staff's interim report on energy conservation.

AWARDS Mr. Johnson was the recipient of the first annual Texas Outstanding Public Service Award in 1988.

MEMBERSHIP American Economics Association.

TESTIMONY ON BEHALF OF TEXAS OFFICE OF PUBLIC UTILITY COUNSEL	Docket No. 6588, Subject:	Re Southwestern Bell Telephone Company, Declassification of Documents.
	Docket Nos. 7195 and 6755, Subject:	Re Gulf States Utilities Company, Rate Design/Cost Allocation.
	Docket No. 7510, Subject:	Re West Texas Utilities Company, Rate Design/Cost Allocation.
	Docket No. 8095, Subject:	Re Texas-New Mexico Power Company, Rate Design/Cost Allocation.
	Docket No. 8363, Subject:	Re El Paso Electric Company, Rate Design/Cost Allocation.
	Docket No. 8425, Subject:	Re Houston Lighting & Power Company, Revenue Requirements.
	Docket No. 8425, Subject:	Re Houston Lighting & Power Company, Rate Design/Cost Allocation.
	Docket No. 8646, Subject:	Re Central Power and Light Company, Revenue Requirements.
	Docket No. 8646, Subject:	Re Central Power and Light Company, Rate Design/Cost Allocation.
	Docket No. 8646, Subject:	Re Central Power and Light Company, Interim Rate Relief.
	Docket No. 8555, Subject:	Proceedings Concerning Houston Lighting & Power Company on Remand From Cause No. C-5705 and Cause No. 352,044, Determination of Remand Amount.
	Docket No. 8928, Subject:	Re Texas-New Mexico Power Company, Rate Design/Cost Allocation.
	Docket No. 8585, Subject:	Re Southwestern Bell Telephone Company, Revenue Requirements/Affiliates.
	Docket No. 8585, Subject:	Re Southwestern Bell Telephone Company, Reply, Revenue Requirements/Affiliates.

Docket No. 8585, Subject:	Re Southwestern Bell Telephone Company, Reply, Rate Design.
Docket No. 8585, Subject:	Southwestern Bell Telephone Company, Proposed Non-Unanimous Stipulation.
Docket No. 9300, Subject:	Texas Utilities Electric Company, Revenue Requirement.
Docket No. 9300, Subject:	Texas Utilities Electric Company, Cost Allocation and Rate Design.
Docket No. 9300, Subject:	Texas Utilities Electric Company, Prudence of Plant Acquisition.
Docket No. 9561, Subject:	Central Power and Light Company, Revenue Requirement.
Docket No. 9561, Subject:	Central Power and Light Company, Cost Allocation and Rate Design.
Docket No. 9578, Subject:	Sugar Land Telephone Company, Inquiry into Sale.
Docket No. 9850, Subject:	Houston Lighting & Power Company, Revenue Requirement.
Docket No. 9850, Subject:	Houston Lighting & Power Company, Cost Allocation and Rate Design.
Docket No. 9850, Subject:	Houston Lighting & Power Company, Settlement Testimony: Revenue Requirement and Rate Design.
Docket No. 9981, Subject:	Central Telephone Company, Revenue Requirement/Affiliates.
Docket No. 10894, Subject:	Gulf States Utilities Company, Affiliate Transactions/Power Purchases.
Docket No. 11735, Subject:	Texas Utilities Electric Company, Revenue Requirement and Rate Design.

Docket No. 11892,	General Counsel's Original Petition for Generic Proceeding Regarding Purchased Power,
Subject:	Impact of Purchased Power on Cost of Capital.
Docket No. 12700,	El Paso Electric Company,
Subject:	Acquisition, Revenue Requirement and Rate Design.
Docket No. 12957,	Houston Lighting & Power Company,
Subject:	Contract Pricing Tariff.
Docket No. 13100,	Texas Utilities Electric Company,
Subject:	Competitive Pricing Tariffs.
Docket No. 13575,	Texas Utilities Electric Company,
Subject:	Demand Side Management and Purchase Power Recovery.
Docket No. 12065,	Houston Lighting & Power Company,
Subject:	Revenue Requirement/Plant Cancellation/Prudence.
Docket No. 12065,	Houston Lighting & Power Company,
Subject:	Cost Allocation and Rate Design.
Docket No. 13943,	Gulf Coast Power Connect,
Subject:	Transmission Line CCN.
Docket No. 13575,	TUEC Application for Relief Regarding Recovery Solicitations,
Subject:	DSM and Purchase Power Cost Recovery.
Docket No. 13369,	West Texas Utilities Company,
Subject:	Cost Allocation and Rate Design.
Docket No. 14435,	Southwestern Electric Power Co.,
Subject:	Rate Design.
Docket No. 14716,	Texas Utilities Electric Company,
Subject:	Wholesale Competitive Rate.
Docket No. 14965,	Central Power and Light Company,
Subject:	Cost Allocation, Rate Design and Competitive Issues.

Docket No. 14965, Central Power and Light Company,
Subject: Reply, Cost Allocation, Rate Design and Competitive Issues.

Docket No. 15560, Texas-New Mexico Power Company,
Subject: Competitive Issues.

Docket No. 16705, Entergy Gulf States, Inc.,
Subject: Cost Allocation, Rate Design and Competitive Issues.

Docket No. 16705, Entergy Gulf States, Inc.,
Subject: Reply, Cost Allocation, Rate Design and Competitive Issues.

Docket No. 16995, Central Southwest Corp.,
Subject: Integrated Resource Planning.

Docket No. 17751, Texas-New Mexico Power Company,
Subject: Rate Design and Competitive Issues.

Docket No. 18845, CPL, WTU, and SWEPCO,
Subject: Integrated Resource Planning.

Docket No. 21527, TXU Financing Order,
Subject: Cost Allocation.

Docket No. 21528, CPL Financing Order,
Subject: Cost Allocation.

Docket No. 21591, Sharyland Utilities Initial Rates & Tariffs,
Subject: Deferrals.

Docket No. 21956, Reliant Business Separation Plan,
Subject: Price to Beat and Capacity Auction.

Docket No. 22344, Generic Rate Design and Customer Classification for TDUs,
Subject: Rate Design.

Docket No. 22349, TNMP Unbundling,
Subject: Competitive Transition Charge and Revenue Requirements/Cost Allocation/Rate Design.

Docket No. 22350,	TXU Unbundling,
Subject:	Competitive Transition Charge.
Docket No. 22351,	Southwestern Public Service Company Unbundling,
Subject:	Cost Allocation/Rate Design.
Docket No. 22352,	Central Power & Light Company,
Subject:	Competitive Transition Charge.
Docket No. 22355,	Reliant Unbundling,
Subject:	Non-Bypassable Charges and Competitive Transition Charge/Cost Allocation/Rate Design.
Docket No.22356,	Entergy Gulf States Utilities Unbundling,
Subject:	Revenue Requirements/Cost Allocation/Competitive Transition Charge/Settlement Rate Design.
Docket No. 24194,	Application of TNMP to Establish Price to Beat Fuel Factor,
Subject:	Fuel and purchased power costs.
Docket No. 25230,	Joint Application for Approval of Stipulation Regarding TXU Electric Company Transition to Competition Issues,
Subject:	Retail Clawback Provisions of Non-Unanimous Agreement.
Docket No. 25314,	Application of West Texas Utilities Company and Mutual Energy WTU to Establish a Fuel Reconciliation Methodology for Southwest Power Pool (SPP) Customers,
Subject:	Fuel Cost Method.
Docket No. 24336,	Application of Entergy Gulf States, Inc. for Approval of Price to Beat Factor,
Subject:	Unaccounted for Energy.
Docket No. 23320,	Petition of ERCOT for Approval of the ERCOT Administrative Fee,
Subject:	ERCOT Fee Structure.
Docket No. 26194,	El Paso Electric Company Fuel Reconciliation,
Subject:	Purchased Power and Off-System Sales.

Docket No. 27576,	Application of Texas-New Mexico Power Company for Reconciliation of Fuel Costs,
Subject:	Fuel Reconciliation.
Docket No. 28813,	Inquiry Into Rates of Cap Rock Energy,
Subject:	Revenue Requirements/Cost Allocation/Rate Design.
Docket No. 28840,	Application of AEP Texas Central Company for Change in Rates,
Subject:	Cost Allocation/Rate Design/Affiliate Transactions.
Docket No. 30485,	Application of CenterPoint Energy Houston Electric, LLC For A Financing Order,
Subject:	Transition Charge Recovery.
Docket No. 30143,	Petition of El Paso Electric Company to Reconcile Fuel Costs (Initial and Rebuttal Testimonies),
Subject:	Fuel Reconciliation.
Docket No. 30706,	Application of CenterPoint Energy Houston Electric, LLC for A Competition Transition Charge,
Subject:	Competitive Transition Charge Structure.
Docket No. 31315,	Application of Entergy Gulf States, Inc. for Approval of Incremental Purchased Capacity Recovery Rider,
Subject:	Purchase Power Capacity Rates.
Docket No. 31544,	Application of Entergy Gulf States, Inc. for Recovery of Transition to Competition Costs,
Subject:	Allocation of Transition Costs.
Docket No. 31994,	Application of Texas-New Mexico Power Company's to Establish a Competition Transition Charge Pursuant to P.U.C. Subst. R. 25.263(N),
Subject:	Competition Transition Charge.
Docket No. 32475,	Application of AEP Texas Central Company for a Financing Order,
Subject:	Securitization of Stranded Costs.

Docket No. 32758,	Application of AEP Texas Central Company for a Competition Transition Charge Pursuant to P.U.C. Subst. R. 25.263(n),
Subject:	Competitive Transition Charge.
Docket No. 32795,	Staff's Petition to Initiate Generic Proceeding to Re-Allocate Stranded Costs Pursuant to PURA § 39.253(f),
Subject:	Stranded Costs Allocation.
Docket No. 32907,	Application of Entergy Gulf States, Inc. for Determination of Hurricane Reconstruction Costs,
Subject:	Cost Allocation.
Docket No. 32766,	Application of Southwestern Public Service Company for: (1) Authority to Change Rates; (2) Reconciliation of its Fuel Costs for 2004 and 2005; (3) Authority to Revise the Semi-Annual Formulae Originally Approved in Docket No. 27751 Used to Adjust its Fuel Factors; and (4) Related Relief,
Subject:	Cost Allocation/Rate Design.
Docket No. 33586,	Application of Entergy Gulf States, Inc. for a Financing Order,
Subject:	Financing Order Allocation.
Docket No. 32710,	Application of Entergy Gulf States, Inc. for Authority to Reconcile Fuel and Purchased Power Costs,
Subject:	Capacity Rider Allocation.
Docket No. 31461,	Application of AEP Texas North Company for a Competition Transition Charge Under to Subst. R. §25.263(N),
Subject:	Competition Transition Charge.
Docket No. 32795,	Staff's Petition to Initiate a Generic Proceeding to Re-Allocate Stranded Costs Pursuant to PURA § 39.253(f),
Subject:	Stranded Cost Allocation.
Docket No. 33309,	Application of AEP Texas Central Company for Authority to Change Rates,
Subject:	Rate Design and Energy Efficiency Costs.

Docket No. 33310,	Application of AEP Texas North Company for Authority to Change Rates,
Subject	Energy Efficiency Costs and Riders.
Docket No. 32902,	CenterPoint Energy Houston Electric, LLC Compliance Tariff,
Subject:	Allocation of Stranded Costs.
Docket No. 34077,	Joint Report and Application of Oncor and EFH Pursuant to § 14.101,
Subject:	Leveraged buyout of utility.
Docket No. 35105,	Compliance Tariff Filing of AEP Texas,
Subject:	Allocation of Stranded Costs.
Docket No. 35038,	Texas-New Mexico Power Company Tariff Filing in Compliance with the Final Order in Docket No. 33106,
Subject:	Allocation of Stranded Costs.
Docket No. 34800,	Application of Entergy Gulf States, Inc. for Authority to Change Rates and to Reconcile Fuel Costs,
Subject:	Cost Allocation & Rate Design.
*Docket No. 37482,	Application of Entergy Texas for a PCRF,
Subject:	Purchase Power.
*Docket No. 37744,	Application of Entergy Texas, Inc. for Authority to Change Rates,
Subject:	Cost allocation, rate design, proposed riders, & storm damage expense.
*Docket No. 38951,	Application of Entergy Texas, Inc. for Approval of CGS Tariff,
Subject:	Rate Design, Competitive Tariffs.
*Docket No. 46454,	Application of SPS for Revision of EECRF[1],
Subject:	Recovery of energy efficiency costs.

1 Asterick (*) denotes testimony for Texas OPC as a consultant.

TESTIMONY ON BEHALF OF STEERING COMMITTEE OF ONCOR CITIES	Docket No. 35634,	Re Oncor Electric Delivery's Request for an Energy Efficiency Cost Recovery Factor,
	Subject:	Energy Efficiency Cost Recovery.
	Docket No. 36958,	Application of Oncor Electric Delivery Company LLC for 2010 Energy Efficiency Cost Recovery Factor,
	Subject:	Energy Efficiency Cost Recovery.
	Docket No. 39375,	Application of Oncor Electric Delivery Company LLC for 2012 EECRF,
	Subject:	Energy Efficiency Cost Recovery.
TESTIMONY ON BEHALF OF ALLIANCE OF XCEL MUNICI-PALITIES	Docket No. 35664,	Application of SPS to Revise Interruptible Credit Option Tariff,
	Subject:	Interruptible Rate Avoided Costs.
	Docket No. 35763,	Application of SPS to Change Rates and Reconcile Fuel and Purchased Power Costs,
	Subject:	Energy Efficiency, Renewable Energy Credits, Power Cost Credits, and Interruptible Credits.
	Docket No. 37173,	Petition for Declaratory Order of Southwestern Public Service Company Regarding the Generation Demand Charge as a Cap on Compensation for Interruptible Resources
	Subject:	Interruptible Curtailable Option ("ICO").
	Docket No. 43695,	Application of SPS to Change Base Rates,
	Subject:	Cost Allocation / Rate Design/ Jurisdictional.
	Docket No. 47527,	Application of SPS to Change Base Rates,
	Subject:	Cost Allocation / Rate Design/ Jurisdictional
TESTIMONY ON BEHALF OF CERTAIN TNMP CITIES	Docket No. 36025,	Application of TNMP for Authority to Change Rates,
	Subject:	Cost Allocation and Rate Design.
	Docket No. 39362,	Application of TNMP for 2012 EECRF,
	Subject:	Energy Efficiency Cost Recovery.

TESTIMONY ON BEHALF OF ST.LAWRENCE COTTON GROWERS	Docket No. 41474,	Application of Sharyland Utilities for Unbundled Delivery Rates,
	Subject:	Cost Allocation, Rate Design, Unbundling.
TESTIMONY ON BEHALF OF LIVE OAK TENANTS	Docket No.41987,	Complaint Against Live Oak Resort,
	Subject:	Sub Metering Complaint Case.
TESTIMONY ON BEHALF OF GULF COAST COALITION OF CITIES	Docket No. 38339,	Application of CenterPoint Energy Houston Electric, LLC for Authority to Change Rates,
	Subject:	Cost Allocation, Rate Design, Riders.
TESTIMONY ON BEHALF OF PENNYSLVANIA OFFICE OF CONSUMER ADVOCATE	Docket No. R-2010-2161575, et. al.,	PECO Energy Co.-Electric Division Base Rate Case,
	Subject:	Cost Allocation and Rate Design.
	Docket No. R-2010-2179522,	Duquesne Light Company Base Rate Case,
	Subject:	Cost Allocation and Rate Design.
	Docket No. R-2014-248745,	Met Edison General Base Rate Case,
	Subject:	Cost Allocation and Rate Design.
	Docket No. R-2014-2478743,	Penelec Power General Base Rate Case,
	Subject:	Cost Allocation and Rate Design.
	Docket No. R-2014-2478744,	Penn Power General Base Rate Case,
	Subject:	Cost Allocation and Rate Design.
	Docket No. R-2014-248752,	West Penn Power General Base Rate Case,

Subject:	Cost Allocation and Rate Design.
Docket No. R-2016-2537349	<u>Met Edison General Base Rate Case</u>,
Subject:	Cost Allocation and Rate Design.
Docket No. R-2016-2537352	<u>Penelec Power General Base Rate Case</u>,
Subject:	Cost Allocation and Rate Design.
Docket No. R-2016-2537355,	<u>Penn Power General Base Rates,</u>
Subject:	Cost Allocation and Rate Design.
Docket No. R-2016-2537359	<u>West Penn Power General Base Rate Case</u>,
Subject:	Cost Allocation and Rate Design.
Docket No. R-2018-3000164	<u>PECO General Rate Case</u>
Subject:	Cost Allocation and Rate Design
Docket No. R-2021-3024601	<u>PECO General Rate Case</u>
Subject:	Cost Allocation and Rate Design

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TESTIMONY ON BEHALF OF SWEPCO CITIES	Docket No. 40443, Subject:	<u>Application of SWEPCO for Rate Change,</u> Cost Allocation, Rate Design, Fuel Rule, Revs.
TESTIMONY ON BEHALF OF SWEPCO CITIES (CARD)	Docket No. 46449, Subject:	<u>Application of SWEPCO for Rate Change,</u> Cost Allocation, Rate Design, Transmission.

Gas Utility (Railroad Commission):

TESTIMONY FOR CITY OF EL PASO	Docket No.10506 Subject:	<u>Texas Gas Services Co.-West Texas</u> Cost Allocation, Rate Design

TESTIMONY FOR CONNECTICUT CONSUMER COUNSEL	Docket No.14-05-06,	<u>CL&P Rate Increase Application,</u>
	Subject:	Cost Allocation, Rate Design, Decoupling.
TESTIMONY FOR TEXAS COAST UTILITIES COALITION	Docket No.44572,	<u>Centerpoint Application for DCRF,</u>
	Subject:	Distribution Cost Recovery Factor.
	Docket No. 47320,	<u>Centerpoint Application for DCRF,</u>
	Subject:	Distribution Cost Recovery Factor.
TESTIMONY FOR CITY OF EL PASO	Docket No.44941,	<u>El Paso Electric Co. Rate Request,</u>
	Subject:	Cost Allocation, Rate Design.
	Docket No. 46831	EPEC Rate Case
	Subject:	Cost Allocation/Rate Design
	Docket No. 48181	EPEC Community Solar Waiver
	Subject:	Regulatory Policy
TESTIMONY FOR TEXAS OPUC (2014 or later)	Docket No.44620,	<u>Sharyland Utilities Good Cause Request,</u>
	Subject:	Transmission Cost Recovery.
	Docket No. 45414, (base rate)	<u>Sharyland Utilities Rate Inquiry,</u>
	Subject:	Rev Req/Allocation/Rate Design.
	Docket No. 46025, (fuel)	<u>Southwestern Public Service Co.,</u>
	Subject:	Fuel and Purchased Power.
	Docket No. 48371,	<u>Entergy Texas Rate Application</u>
		Class Allocation/Rate Design/Riders
	Docket No. 49616,	<u>Southwestern Public Service Co.</u>
	Subject:	Fuel Factor Methodology

Docket No. 50058, El Paso Electric Co. Fuel Reconciliation
Subject: Off System Sales Margin in Fuel

Docket No. 51625, Southwestern Public Service Co.
Subject: Fuel Factor Methodology; Gas Prices

TESTIMONY FOR CITIES SERVED BY AEP	Docket No.49494,	Application of AEP Texas to Adjust Rates
	Subject:	Cost Allocation/Rate Design
TESTIMONY FOR MD. OFFICE OF PEOPLE COUNSEL	Case No.9610,	Application of Baltimore Gas & Electric Co.
	Subject:	Gas/Electric Cost Allocation/Rate Design

ATTACHMENT B

Adjustments to Demand and Energy Factors for COVID

Q. WHAT IS THE PURPOSE OF THIS ATTACHMENT?

A. This attachment is intended to provide additional explanation regarding the adjustment procedure I applied to demand and energy allocation factor, as discussed in Sec. III.C. of the testimony. As discussed in that section, the 2020 test year is used in the CCOS study to determine customer class allocation factors for demand and energy. The impact of COVID occurred in 2020.

Q. HOW DID COVID AFFECT ELECTRICITY USE IN 2020?

A. The primary impact is that residential electricity usage increased significantly in 2020 compared to previous years, and electricity for major business, industrial, and government office customers declined relative to previous years.[1] The most significant driver for this shifting of usage and revenues among customer classes was the governmental health orders which required non-essential workers to stay home and resulted in closure of many businesses. Many employees temporarily ceased workday commuting and if feasible worked from home. The stay at home restrictions were instituted in the last 10 days of March 2020. The principal energy impact of these measures occurred in the second quarter of 2020, with a gradual recovery occurring later in the year as governmental restrictions were eased. However, school closures during 2020 and the reoccurrence of epidemic cases also precluded a complete recovery of electricity usage patterns during 2020. At the national level, prior to the pandemic in

[1] See, Carrasco Testimony Ex. MC-5.

February 2020, 7.6% of households were working from home.[2] In the 2d Quarter of 2020 (May 2020), this figure quadrupled with 31.4% of households working from home. [3] The work from home percentage declined in each month subsequent to May 2020. [4] By December 2020, the 2d Quarter work from home percentage had declined by one-third to 20%.[5]

Q. WHICH CLASSES' ALLOCATION FACTORS DID YOU ADJUST?

A. The customer classes subject to adjustment were: Residential, Small General Service, General Service, Large General Service, Petroleum Refining, and City/County. COVID-19 increased residential electric usage and decreased electric usage by the five non-residential classes. The pandemic caused an increase in residential electric usage roughly equal to the combined reduction in electric usage by the five non-residential classes. For example, using the three year average for 2017-2019 as the benchmark, the residential energy allocation factor increase was 4.43 percentage points, compared to the cumulative 4.3 percentage decrease for the non-residential classes.[6] Only these major classes were adjusted in order to minimize revisions to 2020 data. By adjusting the allocation factors for COVID impact, the CCOS study can be used to evaluate the Company's proposed class cap and floor, which is the Company's rate making approach to the pandemic effect.

Q. PLEASE DESCRIBE THE BASIC APPROACH TO NORMALIZING THE ALLOCATION FACTORS.

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[2] "Work From Home Before And After the COVID 19 Outbreak, "Federal Reserve Bank of Dallas, Bick, Blandon, Merton, Working Paper 2017, Feb. 2021, Figure 1, page 10.
[3] Ibidem.
[4] Ibidem.
[5] Ibidem.
[6] Ex. MC-5, E-1 sheet.

A. For the six customer classes, above, the D1, D2, and E1 allocation factors were normalized based on three-year 2017-2019 allocation factors as set out in Mr. Carrasco's Ex. MC-5. To reflect differences between E1 and E2 allocation factors (which is based on interruptible sales), the affected classes are adjusted based on the E1 and E2 differentials in Schedule P-7. The three-year average period is reasonable, because the term is sufficient to avoid anomalies but avoids structural changes in class composition which may occur over periods longer than three years. The Company, itself, utilizes a three year period, 2017-2019, in order to normalize other operating revenues for COVID impact.[7] In some jurisdictions , utilities use three year averages, in the normal course of business, to develop the demand and energy factors for the CCOS study.[8]

Q. PLEASE DESCRIBE THE ADJUSTMENT FOR D-12 AND NCP ALLOCATION FACTORS.

A. For the selected classes, the three-year average E1 allocators were utilized to develop average demand. The 2020 12 CP and NCP load factors are applied to the average demand in order to develop D-12 and NCP allocation factors.

Q. WHAT ARE THE DEMAND AND ENERGY ALLOCATION FACTORS AFTER YOU INCORPORATED THE ADJUSTMENTS INTO THE COMPANY'S REGULATORY MODEL?

A. The allocation factors are shown on as follows:

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7 Carrasco at 13; Table MC-7.

8 See, for example, Baltimore Gas & Electric Co. in Maryland.

ADJUSTED ALLOCATION FACTORS

	RES	SGS	R. Light	Lighting	Traffic	Pumping	E. Refin.	Irrigation
D8DIST	67.26%	5.97%	0.29%	0.39%	0.01%	2.13%	0.00%	0.19%
D9DIST	54.08%	5.29%	0.41%	0.55%	0.01%	2.41%	0.00%	0.14%
DPROD12	47.78%	5.03%	0.19%	0.31%	0.02%	1.52%	0.65%	0.07%
DTRAN12	44.14%	4.88%	0.15%	0.27%	0.02%	1.89%	0.65%	0.07%
E1ENERGY	37.81%	4.80%	0.06%	0.61%	0.04%	2.91%	0.69%	0.07%

	GS	LPS	P. Refin.	A. Light	Furnace	Military	Cotton Gin	City/Coty	W. Heat
D8DIST	14.22%	6.03%	0.00%	0.30%	0.00%	0.00%	0.08%	2.74%	0.39%
D9DIST	24.02%	7.14%	0.00%	0.42%	0.00%	0.00%	0.12%	5.16%	0.24%
DPROD12	23.83%	8.74%	3.08%	0.23%	0.50%	3.95%	0.01%	4.05%	0.04%
DTRAN12	26.53%	8.88%	3.69%	0.20%	0.45%	4.04%	0.02%	4.09%	0.04%
E1ENERGY	26.64%	11.14%	5.38%	0.46%	0.35%	4.50%	0.03%	4.43%	0.09%

	RES	SGS	R. Light	Lighting	Traffic	Pumping	E. Refin.	Irrigation	GS
D1PROD	44.83%	5.70%	0.03%	0.30%	0.02%	1.62%	0.52%	0.10%	27.25%
D2PROD	45.27%	5.75%	0.00%	0.00%	0.01%	1.59%	0.52%	0.10%	27.41%
D2TRAN	45.27%	5.75%	0.00%	0.00%	0.01%	1.59%	0.52%	0.10%	27.41%

	GS	LPS	P. Refin.	A. Light	Furnace	Military	Cotton Gin	City/Coty	W. Heat
D1PROD	27.25%	7.88%	2.95%	0.23%	0.34%	3.51%	0.01%	4.67%	0.04%
D2PROD	27.41%	7.89%	2.93%	0.00%	0.34%	3.49%	0.00%	4.67%	0.03%
D2TRAN	27.41%	7.89%	2.93%	0.00%	0.34%	3.49%	0.00%	4.67%	0.03%

Q. WHY DO YOU INCLUDE A REVENUE ADJUSTMENT AMONG THE SIX CLASSES WHICH ARE SUBJECT TO ADJUSTED ALLOCATION FACTORS?

A. The allocation factor changes result in a revision to the amount of non-fuel costs assigned to the customer classes. However, theoretically the impact of COVID on allocation factors should be accompanied by shifts in revenues. In order to provide a more balanced view of class cost of service, the relationship of current revenues among classes should be adjusted. This estimation is challenging, but necessary. My approach is to estimate the portion of increased 2020 residential revenues which is likely due to COVID work from home impact. Residential current revenue will be reduced by this amount, and the same amount will be credited to the five non-residential classes subject to allocation factor adjustment.

Q. PLEASE DESCRIBE THE PROCEDURE FOR ADJUSTING RESIDENTIAL REVENUES FOR COVID IMPACT.

A. The first step is quantifying the increase in residential revenues between 2019 and 2020. The adjusted residential revenues from EPE's 2019 Earnings Monitoring Report (EMR) are compared to 2020 adjusted test year residential revenues from RFP Schedule Q-1.[9] The 2020 increase in residential revenues is $36.56 million. The second step is to estimate the portion of this residential increase which is COVID-related as opposed to growth for any other reasons or conditions. Because residential revenues are generated primarily by kWhs, the 2019 EMR's weather adjusted monthly residential kWh is compared to the adjusted test year monthly kWh in RFP Schedule O-1.04. The residential 2020 total kWh is 11.3% higher than 2019. The COVID impact begins in the second quarter of 2020. Therefore, a comparison between the first quarters of 2020 and 2019 can provide information regarding the non-COVID level of residential sales growth. The first quarter 2020 sales growth is 6.7%, which is assumed to be non-COVID-related. If this same percentage of non-COVID kWh growth occurred during the remaining three quarters of 2020, then 40.8% of the 2020 residential growth is COVID-related.[10] Based on this percentage, $14.99 million of 2020 residential revenue growth will be classified as COVID-related.[11]

[9] Both the EMR revenues and the Q-1 revenues are adjusted for weather and customer annualizations.

[10] 6.7% / 11.3%= 59.2%.

[11] $36.567 million X 41% = $14.99 million.

Q. WHAT IS THE NEXT STEP IN RECOGNIZING THE $14.9 MILLION OF RESIDENTIAL REVENUE IMPACT?

A. The $14.9 million is excluded from residential current revenues and credited to the five non-residential classes' current revenues in proportion to impact of the allocation adjustment on those classes. The revenue adjustment is as follows: Residential -$14.99 million; Small General $1.42 million; General Service $8.18 million; Large Power $2.19 million; Petroleum Refining $369 thousand; City/County $2.82 million.

Interruptible Non-Compliance

Re-billed Revenues

2016	$ 2,147,073
2017	$ 2,352,650
2018	$ 1,753,411
2019	$ -
2020	$ 1,212,341
Five Year Avg.	$ 1,493,095

source: CEP 14-9, Carrasco Direct at 11;
Sched. O-4.01 at 9

Company's EEP Revenue Adjustment By Class

			Revenue		
		kWh	Non-Fuel	Fuel	Total
Residential	01	(4,535,420)	$ (441,520)	$ (58,191)	$ (499,711)
Small General	02	(1,057,867)	$ (115,013)	$ (13,532)	(128,545)
Irrigation	22	(169,888)	$ (16,191)	$ (2,173)	(18,364)
General	24	(8,668,914)	$ (387,015)	$ (110,836)	(497,851)
Large Power	25	(4,640,216)	$ (58,505)	$ (65,461)	(123,966)
City /County	41	(2,585,047)	$ (83,562)	$ (33,121)	(116,683)
Total Texas		**(21,657,352)**	**$ (1,101,806)**	**$ (283,314)**	**$ (1,385,120)**

Adjusted CCOS Study: EPE Proposed Revenue Requirement

	Texas Retail	Residential Service	Small General	Recreat. Lighting	Street Light	Traffic Signs	Municipal Pumping	Electric Refining	Irrigation Service	General Service
Base Rev Req	574,531,417	288,019,784	33,625,124	597,006	2,975,707	96,927	10,298,839	1,802,863	589,724	137,035,498
Rev Adjustment		(14,992,000)	1,421,743							8,184,516
Current Revs	532,713,639	258,646,830	34,741,428	462,980	4,046,620	95,204	10,102,350	1,830,063	423,413	133,190,256
Required Change	41,817,778	29,372,954	(1,116,304)	134,026	(1,070,913)	1,723	196,489	(27,200)	166,311	3,845,242
Percentage	7.8%	11.4%	-3.2%	28.9%	-26.5%	1.8%	1.9%	-1.5%	39.3%	2.9%
Ratio to Total		145%	-41%	369%	-337%	23%	25%	-19%	500%	37%

	Large Power	Petroleum Refinery	Area Lighting	Electric Furnace	Military Reservation	Cotton Gin	City and County	Water Heating
Base Rev Req	41,703,625	13,822,426	2,666,757	1,492,901	14,844,028	175,427	23,945,144	839,636
Rev Adjustment	2,189,774	368,503					2,827,464	
Current Revs	38,145,438	11,333,273	2,932,614	1,191,760	13,009,892	132,972	21,953,964	474,582
Required Change	3,558,187	2,489,153	(265,857)	301,141	1,834,136	42,455	1,991,181	365,054
Percentage	9.3%	22.0%	-9.1%	25.3%	14.1%	31.9%	9.1%	76.9%
Ratio to Total	119%	280%	-115%	322%	180%	407%	116%	980%

Notes: Assumes EPE Proposed Interruptible Increase

Adjusted CCOS Study: CEP Proposed Revenue Reduction

	Texas Retail	Residential Service	Small General	Recreat. Lighting	Street Light	Traffic Signs	Municipal Pumping	Electric Refining	Irrigation Service
Total Revenue Requirement	703,739,734	334,691,932	39,113,818	648,783	3,681,293	141,379	13,877,249	3,134,053	658,257
Other Operating Revenues	(181,083,928)	(57,245,979)	(9,991,213)	(95,874)	(889,775)	(52,353)	(4,471,468)	(1,535,913)	(140,412)
Base Revenue Requirement	522,655,806	277,445,953	29,122,605	552,909	2,791,517	89,026	9,405,781	1,598,140	517,844
Current Revenues	$ 532,713,639	$ 273,638,830	$ 33,319,685	$ 462,980	$ 4,046,620	$ 95,204	$ 10,102,350	$ 1,830,063	$ 423,413
Indicated Revenue Change	$ (10,057,833)	$ 3,807,123	$ (4,197,080)	$ 89,929	$ (1,255,103)	$ (6,178)	$ (696,569)	$ (231,923)	$ 94,431
	-1.89%	1.39%	-12.60%	19.42%	-31.02%	-6.49%	-6.90%	-12.67%	22.30%

	General Service	Large Power	Petroleum Refinery	Area Lighting	Electric Furnace	Military Reservation	Cotton Gin	City and County	Water Heating
Total Revenue Requirement	169,902,632	55,763,038	22,118,685	3,184,302	5,504,524	21,843,106	202,607	28,328,688	945,390
Other Operating Revenues	(53,784,771)	(20,148,130)	(9,883,398)	(657,092)	(4,142,690)	(8,371,293)	(40,356)	(9,463,376)	(169,834)
Base Revenue Requirement	116,117,861	35,614,908	12,235,287	2,527,210	1,361,833	13,471,812	162,251	18,865,312	775,556
Current Revenues	$ 125,005,740	$ 35,955,664	$ 10,964,770	$ 2,932,614	$ 1,191,760	$ 13,009,892	$ 132,972	$ 19,126,500	$ 474,582
Indicated Revenue Change	$ (8,887,879)	$ (340,756)	$ 1,270,517	$ (405,404)	$ 170,073	$ 461,920	$ 29,279	$ (261,188)	$ 300,974
	-7.11%	-0.95%	11.59%	-13.82%	14.27%	3.55%	22.02%	-1.37%	63.42%

Source: Karl Nalepa Testimony
Incorporates Rev Adjustments

Recommended Class Revenue Increase Based On EPE Proposed Revenues

	Texas Retail	Residential Service	Small General	Recreat. Lighting	Street Light	Traffic Signs	Municipal Pumping	Electric Refining	Irrigation Service	General Service
CCOS Increase	$39,296,582	$27,832,376	($1,273,401)	$131,043	($1,088,149)	$1,299	$157,369	($35,131)	$164,023	$3,411,675
Percent Increase	7.38%	10.76%	-3.67%	28.30%	-26.89%	1.36%	1.56%	-1.92%	38.74%	2.56%
Revenue Change	$ 39,294,504	$ 27,314,285	$ -	$ 48,893	$ -	$ 1,329	$ 161,036	$ -	$ 44,714	$ 3,491,167
(Recommended)	7.38%	10.56%	0.00%	10.56%	0.00%	1.40%	1.59%	0.00%	10.56%	2.62%

	Large Power	Petroleum Refinery	Area Lighting	Electric Furnace	Military Reservation	Cotton Gin	City and County	Water Heating
CCOS Increase	$3,420,400	$2,442,539	($273,463)	$296,189	$1,781,711	$41,748	$1,927,314	$359,040
Percent Increase	8.97%	21.55%	-9.32%	24.85%	13.70%	31.40%	8.78%	75.65%
Revenue Change	$ 3,500,096	$ 1,196,845	$ -	$ 125,855	$ 1,373,904	$ 14,042	$ 1,972,220	$ 50,118
(Recommended)	9.18%	10.56%	0.00%	10.56%	10.56%	10.56%	8.98%	10.56%

Notes: *For Comparability, Company Increase Adjusted Based On Carrasco Table MC-8.*
Assumes Company proposed interruptible rates.
Rate moderation procedure resulted in rounding differences.

Recommended Class Revenue Change (Revenue Reduction)

	Texas Retail	Residential Service	Small General	Recreat. Lighting	Street Light	Traffic Signs	Municipal Pumping	Electric Refining	Irrigation Service
Class Revenue Change	$ (10,057,833)	$ -	$ (2,592,638)	$ -	$ (775,307)	$ (3,816)	$ (430,287)	$ (143,264)	$ -
Percentage Change	-1.89%	0.00%	-7.78%	0.00%	-19.16%	-4.01%	-4.26%	-7.83%	0.00%

	General Service	Large Power	Petroleum Refinery	Area Lighting	Electric Furnace	Military Reservatioı	Cotton Gin	City and County	Water Heating
Class Revenue Change	$ (5,490,257)	$ (210,493)	$ -	$ (250,428)	$ -	$ -	$ -	$ (161,342)	$ -
Percentage Change	-4.39%	-0.59%	0.00%	-8.54%	0.00%	0.00%	0.00%	-0.84%	0.00%

Compare to CEP CCOS, CJ-4

Incremental Generation Capacity Cost
Per U.S. EIA 2021 Outlook

	Per kW
EIA CT Capacity--2022 In Service Date	**$ 594.00**
Construction Cost El Paso Region	
(WECC-Southwest)	
Levelized Fixed Charge Rate	**7.39%**
Levelized Cost per kW	**$ 43.90**
Fixed O&M Expense Per EIA	**$7.04**
Sub Total	**$ 50.94**
Add Reserve Margin (15%)	**$ 58.58**
Monthly at Transmission Voltage	**$ 4.98**
Monthly at Primary Voltage	**$ 5.17**
Monthly at Transmission Voltage	**$ 5.27**

Sources:

U.S. Energy Information Administration "Assumptions to Annual Energy Outlook 2021"

February 2021, Tables 4 and 5.

WP/Q-7 (a)

DeAnn T. Walker
Chairman

Arthur C. D'Andrea
Commissioner

Shelly Botkin
Commissioner

John Paul Urban
Executive Director

Greg Abbott
Governor

Public Utility Commission of Texas

TO: Interested Persons

FROM: Therese Harris, Infrastructure Division

DATE: November 4, 2020

RE: Project No. 38578 - Energy Efficiency Implementation Project under 16 TAC § 25.181(q)

Avoided Cost of Capacity and Energy for the 2021 Program Year

Avoided Cost of Capacity

As shown below from the United States Department of Energy's Energy Information Administration's (EIA) Cost and Performance Characteristics of New Central Station Electricity Generating Technologies associated with EIA's Annual Energy Outlook 2020, the base overnight cost of a combustion turbine—industrial frame is $626 per kilowatt (kW) in the Texas Reliability Entity or Electric Reliability Council of Texas (ERCOT) region. Because this amount is less than the $700 per kW threshold set by 16 Texas Administrative Code (TAC) § 25.181(d)(2)(A)(ii), the avoided cost of capacity is $80 per kW-year for 2021.

Avoided Cost of Energy

As stated in its filing on November 2, 2020 in this project, ERCOT calculated the avoided cost of energy for 2021 using the methodology required in 16 TAC § 25.181(d)(3)(A). ERCOT's filing shows the avoided cost for energy for 2021 is $101.61/MWh, which is equivalent to $0.10161/kilowatt-hours (kWh).

Customer Charge Comparison

Electric Utility	Cus Ch	Meter Ch	Monthly
CEHE	2.3	2.09	$ 4.39
Oncor	0.9	2.52	$ 3.42
AEP TX	1.4	3.39	$ 4.79
TNMP	1.13	6.72	$ 7.85
SPS			$ 10.00
SWEPCO			$ 8.40
ETI			$ 10.00
Average			**$ 6.98**
EPE Proposed Charge: Ratio to Average			**151%**

Residential Customer Costs
For EPE Customer Charge

	Invested Capital	
Res Meters & Services (Gross)	$	78,022
Net Plant (Less Acc Deprec)	$	38,636
ADFIT	$	(6,597)
Customer Deposits , Advances	$	(2,447)
Rate Base	$	29,592
Times Fixed Charge	$	3,846
	O&M Expense	
Res Meters-Operations	$	881
Res Meters-Maintenance	$	60
Customer Accounting A901-903	$	11,812
Prorated pension & benefit	$	1,962
Total Expense	$	14,714
Total Customer Charge Costs	**$**	**18,561**
Residential Customers (annual)		3,665
Monthly Customer Charge	**$**	**5.06**

Note: Costs and Bills In Thousands

Develop Fixed Charge Rate	
EPE Proposed Rate of Return	7.98%
Including FIT Gross Up	10.9%
Depreciation	2.1%
Fixed Charge Rate	13.0%

Revised Residential Energy Rate Differential

	EPE Proposed	Revised	Difference
Energy Charge ($/kWh) Jun-Sep, First 600 kWh	$0.11827	$0.11388	($0.00439)
Energy Charge ($/kWh) Oct-May, Above 600 kWh	$0.12827	$0.12088	($0.00739)
Energy Charge ($/kWh) Non-Summer	$0.09827	$0.10388	$0.00561

The following files are not convertible:

DN 52195 Clarence Johnson Schedules-Direct Testimony.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.