Q. HOW ARE POWER PRODUCTION EXPENSES CLASSIFIED?

A. Fuel and purchased power expenses do not have a base-rate impact since they are recovered (off-set) by fuel-related revenues. All fuel-related expenses and revenues are assigned to the Energy-Fuel component. The remaining non-fuel, energy-related costs are assigned to the Energy-Other component. The demand-related production O&M costs like load-dispatching costs are assigned to the Demand Production component.

Q. HOW ARE TRANSMISSION O&M EXPENSES CLASSIFIED?

A. Similar to Transmission plant, all Transmission O&M expenses fall under the Transmission component of Demand.

Q. HOW ARE DISTRIBUTION O&M EXPENSES ALLOCATED TO DEC COMPONENTS?

A. Similar to the CCOS study, Distribution O&M expenses are allocated based on the related distribution plant account allocation. An exception is when using a blended allocator for supervision and engineering accounts and the miscellaneous distribution expense. Also, rents are allocated based on total distribution plant as in the CCOS study. Similar to distribution plant, distribution O&M expenses will have both Demand and Customer components.

Q. HOW ARE CUSTOMER SERVICE EXPENSES CLASSIFIED?

A. All customer service expenses will be classified as Customer-related. Account No. 902 - Meter Reading Expense is assigned to the Customer - 902 Meter Reading component. Account No. 903 - Customer Record & Collections is assigned to the Customer – 903 - Customer Rec & Collections component. Account No. 904 - Uncollectible Accounts, Account No. 905 - Misc. Customer Accounts Expenses, and Account No. 909 - Informational and Instructional Advertising Expenses are all classified under the Customer – Other component.

Q. HOW ARE ADMINISTRATIVE AND GENERAL EXPENSES ALLOCATED TO

DEC COMPONENTS?

A. Similar to the CCOS, if the A&G reg account description is detailed enough, allocation of such costs can be determined by function and classification. The remaining A&G expenses in which a specific function cannot be determined are allocated on the LABOR allocation factor spreading the costs among Demand, Energy, and Customer components.

Q. HOW DOES EPE ALLOCATE DEPRECIATION AND AMORTIZATION EXPENSES TO DEC COMPONENTS?

A. EPE allocates depreciation and amortization expenses by the function consistent with the allocation of the associated plant and accumulated depreciation accounts.

Q. HOW ARE INCOME TAXES ALLOCATED TO DEC COMPONENTS?

A. Consistent with the JCOS and CCOS, deferred income taxes are allocated using a net plant allocator unless another function is specified in the account and current income taxes are calculated by DEC component.

Q. HOW ARE TAXES OTHER THAN INCOME TAXES ALLOCATED TO DEC COMPONENTS?

A. Payroll and unemployment taxes are allocated based on a labor allocation factor. Assignment of property taxes to each DEC component is consistent with how each plant in service functional grouping is allocated. Revenue-related taxes are allocated on a rate-base allocation factor. Other taxes such as sales and use taxes are allocated based on a gross plant allocator.

Q. IS THERE A SCHEDULE THAT PRESENTS HOW THE EXPENSES ARE ASSIGNED TO DEMAND, ENERGY, AND CUSTOMER?

A. Yes. Schedule P-4 itemizes all of the expenses along with the allocator and presents them by the Demand, Energy, and Customer classifications.

Q. WHAT SCHEDULE SUMMARIZES THE OVERALL RESULTS OF DEMAND, ENERGY, AND CUSTOMER COMPONENTS STUDY FOR EACH RATE CLASS?

A. Schedule P-6 summarizes the results of the DEC Study by rate class and calculates the DEC components on a cost-per-unit basis.

VII. Baseline for Distribution Cost Recovery Factor

Q. WHAT IS THE DISTRIBUTION COST RECOVERY FACTOR?

A. A distribution cost recovery factor ("DCRF") is a rate mechanism under section 36.210 of the Public Utility Regulatory Act ("PURA") that allows an electric utility to periodically adjust its rates for changes in certain distribution costs. The Commission has adopted 16 Texas Administrative Code ("TAC") § 25.243 (the "DCRF Rule") to implement PURA section 36.210, which allows a utility not offering customer choice such as EPE to file a DCRF application.

Q. HAS EPE IMPLEMENTED A DCRF?

A. Yes. EPE's initial baseline was approved in EPE's last base rate case, Docket No. 46831, and EPE's first DCRF was approved in Docket 49395[2], and the Company's second DCRF application was approved by the Commission on May 21, 2021, in Docket No. 51348[3]. Mr. Carrasco discusses the inclusion of DCRF revenues in base rates in his testimony.

Q. WHAT IS EPE REQUESTING IN THIS CASE RELATED TO A DCRF?

A. EPE is requesting that the Commission establish a new baseline revenue requirement amount for EPE's distribution function, as defined by the DCRF Rule.

Q. WHAT FORMULA DOES 16 TAC § 25.243 PRESCRIBE FOR SETTING THE DCRF?

A. 16 TAC § 25.243 prescribes the following formula:

$$= [((DIC_C - DICR_C) * ROR_{AT}) + (DEPR_C - DEPR_{RC}) + (FIT_C - FIT_{RC}) + (OT_C - OT_{RC}) - \Sigma(DISTREV_{RC\text{-}CLASS} * \%GROWTH_{CLASS})] * ALLOC_{CLASS} / BD_{C\text{-}CLASS}$$

Where:

DIC_C = Current Net Distribution Invested Capital.

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[2] Application of El Paso Electric Company for a Distribution Cost Recovery Factor, Docket No. 49395, Order (Sept. 27, 2019).

[3] Application of El Paso Electric Company to Amend its Distribution Cost Recovery Factor, Docket No. 51348, Order (May 24, 2021).

DIC_{RC} = Net Distribution Invested Capital from the last comprehensive base-rate proceeding.

ROR_{AT} = After-Tax Rate of Return

$DEPR_{C}$ = Current Depreciation Expense

$DEPR_{RC}$ = Depreciation Expense

FIT_{C} = Current Federal Income Tax

FIT_{RC} = Federal Income Tax

OT_{C} = Current Other Taxes (taxes other than income taxes and taxes associated with the return on rate base), as related to DIC_{C}, calculated using current tax rates and the methodology, and not including municipal franchise fees.

OT_{RC} = Other Taxes, as related to DIC_{RC} and not including municipal franchise fees.

$DISTREV_{RC\text{-}CLASS}$ (Distribution Revenues by rate class based on Net Distribution Invested Capital from the last comprehensive base-rate proceeding) = ($DIC_{RC\text{-}CLASS}$ * ROR_{AT}) + $DEPR_{RC\text{-}CLASS}$ + $FIT_{RC\text{-}CLASS}$ + $OT_{RC\text{-}CLASS}$.

%GROWTHCLASS (Growth in Billing Determinants by Class)

$DIC_{RC\text{-}CLASS}$ = Net Distribution Invested Capital allocated to the rate class from the last comprehensive base-rate proceeding.

Q. HOW IS DISTRIBUTION INVESTED CAPITAL ("DIC") DEFINED IN 16 TAC § 25.243?

A. 16 TAC § 25.243(b)(3) defines distribution invested capital as

> parts of the electric utility's invested capital, as described in PURA § 36.053, that are categorized as distribution plant, distribution-related intangible plant, and distribution-related communication equipment and networks properly recorded in Federal Energy Regulatory Commission (FERC) Uniform System of Accounts 303, 352, 353, 360 through 374, 391 and 397. Distribution invested capital includes only costs: for plant that has been placed into service; that comply with PURA, including § 36.053 and § 36.058; and that are prudent, reasonable, and necessary.

Q. HOW DID YOU CALCULATE THE BASELINE DISTRIBUTION REVENUE REQUIREMENT?

A. The baseline distribution revenue requirement is calculated as defined in the DCRF Rule at 16 TAC § 25.243(d)(1) for DISTREV. It states that Distribution Revenue by Rate

Class on net distribution capital from the last comprehensive base-rate proceeding is the product of Distribution Invested Capital (DIC_{RC}) and after tax Rate of Return (ROR) plus current depreciation (DEP_{RC}), current Federal Income Tax ($FIT_{RC\text{-}CLASS}$), and Other Current Taxes ($OT_{RC\text{-}CLASS}$). Accordingly, Net Distribution Invested Capital is the sum (Σ) for all rate classes as expressed by the full DCRF formula above. Also, 16 TAC § 25.243(d)(1) is a description of the DCRF formula assuming that a baseline for the cost recovery factor has already been established. However, the data utilized is from the current case, extracted to establish the baseline within this proceeding. Exhibit AH-5 itemizes the calculation in lines 2-29 with the total DISTREV being represented on line 29.

Q. PLEASE DESCRIBE THE CALCULATION OF THE RETURN ON DIC IN MORE DETAIL.

A. The return component is calculated from net distribution invested capital multiplied by the after-tax rate of return. 16 TAC § 25.243(d)(2) defines the after-tax rate of return as "the rate of return approved by the commission in the electric utility's last comprehensive base-rate proceeding if the final order (which may be an order on rehearing) approving the rate of return was filed less than three years before the application for a DCRF was filed." As indicated in the rule, only the FERC accounts delineated in section 16 TAC § 25.243(b)(3) of the rule are included in the equation. The balance of these accounts can be seen in Exhibit AH-5, line 2. Thereafter, this balance is adjusted for accumulated depreciation and amortization, and accumulated deferred income tax. This new total (DIC_C) shown in line 8 of Exhibit AH-5 is then multiplied by the rate of return to produce the required return on Distribution Invested Capital. No transmission costs are included in this calculation.

Q. HOW ARE THE DEPRECIATION, INCOME TAX, AND PROPERTY TAX BASELINE COMPONENTS OF THE DISTRIBUTION REVENUE REQUIREMENT DETERMINED?

A. 16 TAC § 25.243(d)(1) defines the depreciation, federal income tax, and other tax baseline components as values from the last comprehensive base-rate proceeding.

Depreciation expense is listed on line 12 of Exhibit AH-5. Property Taxes and Federal Income Tax are expressed on lines 13 and 22, respectively, of Exhibit AH-5. To appropriately allocate the distribution functions share of these taxes, allocators are produced in Exhibit AH-5.

Q. HOW DID YOU CALCULATE THE ADIT AMOUNT USED IN THE CALCULATION OF THE DIC?

A. Plant-related Accumulated Deferred Income Taxes ("ADIT") is reflected on Schedule P-3. This balance is allocated to produce the distribution portion of ADIT. The distribution balance of ADIT is seen on line 7 of Exhibit AH-5 and the associated allocations are seen and developed within Exhibit AH-5.

Q. WHAT RATE OF RETURN DID YOU USE?

A. The Company requested WACC of 7.985% is the rate of return used to calculate the return on Distribution Invested Capital. See line 9 of Exhibit AH-5.

Q. WHERE IS THE DATA LOCATED THAT IS BEING USED FOR THE DIC?

A. As a part of its comprehensive rate-case filing, EPE has submitted Schedules P-2, P-3, P-10, and K-1 that support the total Texas Jurisdictional Company data quantifying its current distribution investment costs.

Q. WHAT IS THE RETURN ON DISTRIBUTION INVESTED CAPITAL?

A. The return on distribution invested capital is $51,260,850 and it is shown in Exhibit AH-5, line 10.

Q, HOW DID YOU CALCULATE THE DCRF BASELINE VALUES INCLUDED IN EXHIBIT AH-5?

A. The Texas jurisdictional values included in the DCRF baseline are taken from Schedules P-2 and P-3. These jurisdictional values are allocated to the distribution function in Exhibit AH-5 with support from Schedule P-10.

Q. 16 TAC § 25.243 REQUIRES A CALCULATION OF DISTRIBUTION REVENUES BY RATE CLASS FROM THE LAST COMPREHENSIVE BASE-RATE PROCEEDING. HAVE YOU MADE THAT CALCULATION?

A. Yes. Please see lines 41–110, column $DISTREV_{RC\text{-}CLASS}$, of Exhibit AH-5. These calculations are produced to establish a baseline for this rate case proceeding.

Q. 16 TAC § 25.243(d)(1) REQUIRES A CALCULATION OF DISTRIBUTION RATE CLASS ALLOCATORS FROM THE LAST COMPREHENSIVE BASE RATE PROCEEDING. HAVE YOU MADE THAT CALCULATION?

A. Yes. These calculations are produced to establish a baseline for this rate case proceeding. Please see lines 41–110, column $ALLOC_{CLASS}$, of Exhibit AH-5.

Q. WHAT REVENUE REQUIREMENT IS EPE ASKING THE COMMISSION TO SET FOR PURPOSES OF ESTABLISHING A DCRF BASELINE?

A. The total amount is $92,711,343 million and can be found on page 1, line 29 of Exhibit AH-5. The same amount is produced as a sum of each rate class on page 2, line 110, column $DISTREV_{RC\text{-}CLASS}$, of the DCRF baseline values calculation provided in Exhibit AH-5.

Q. DOES EPE INTEND TO FILE A DCRF RATE RIDER IN THIS PROCEEDING?

A. No. EPE seeks approval of a revised DCRF baseline in this proceeding allowing for future cost recovery of "prudent, reasonable, and necessary" distribution invested capital as set forth by PURA section 36.053 and pursuant to 16 TAC § 25.243 by calculating the distribution revenue requirement and the associated rates by customer rate class. Establishing a new baseline in this case will allow EPE to evaluate whether a DCRF proceeding in the future is warranted.

VIII. Baseline for Transmission Cost Recovery Factor

Q. WHAT IS THE TRANSMISSION COST RECOVERY FACTOR?

A. A Transmission Cost Recovery Factor ("TCRF") is a rate mechanism provided for by the PUCT under PURA section 36.209 that allows an electric utility to periodically adjust its rates for changes in certain transmission costs via a tariff. PURA section 36.209 describes the purpose of the TCRF as:

> to recover its reasonable and necessary costs for transmission infrastructure improvement and changes in wholesale transmission charges to the electric utility under a tariff approved by the federal regulatory authority to the extent that the costs or charges have not otherwise been recovered and are incurred after December 31, 2005."

The Commission adopted 16 TAC § 25.239 (the "TCRF Rule") to implement this factor.

Q. HAS EPE IMPLEMENTED A TCRF?

A. Yes. EPE's initial baseline was approved in EPE's last base rate case, Docket No. 46831, and EPE's first TCRF was approved in Docket No. 49148[4].

Q. WHAT IS EPE REQUESTING IN THIS CASE RELATED TO A TCRF?

A. EPE is requesting that the Commission establish a new baseline revenue requirement amount for EPE's transmission function as defined by the TCRF Rule.

Q. WHAT FORMULA DOES 16 TAC § 25.239 PRESCRIBE FOR SETTING THE TCRF?

A. 16 TAC § 25.239 prescribes the following formula:

$$TCRF = \frac{RR * ClassALLOC}{BD}$$

Where:

TCRF = transmission cost recovery factor in dollars per unit, for billing each customer class.

RR = transmission cost recovery factor revenue requirement (see formula in response to next question below).

ClassALLOC = the customer class allocation factor used to allocate the transmission revenue requirement in the utility's most recent base rate case.

BD = each customer class's annual billing determinant (kilowatt-hour, kilowatt, or kilovolt-ampere) for the previous calendar year.

[4] Application of El Paso Electric Company for a Transmission Cost Recovery Factor, Docket No. 49148, Order (Dec. 16, 2019).

Q. WHAT PART OF THIS FORMULA IS EPE PROVIDING IN THIS PROCEEDING?

A. EPE is providing transmission cost recovery factor revenue requirement ("RR") as required by 16 TAC § 25.239(e) using the following equation:

$$RR = [revreqt + ATC]*ALLOC$$

Where:

Revreqt = the sum of the return on TIC, net of accumulated depreciation and associated accumulated deferred income taxes, plus investment-related expenses such as income taxes, other associated taxes, depreciation, and transmission–related miscellaneous revenue credits, but not including operation and maintenance expenses or administrative expenses. The return on TIC shall be calculated by multiplying the TIC by the utility's weighted-average cost of capital ("WACC") as established for the utility in a final commission order in a base rate case,

ATC = Approved Transmission Charges

ALLOC = the utility's Texas retail allocation of transmission revenue requirements

Q PLEASE EXPLAIN THE "REVREQT" COMPONENT OF THE REVENUE REQUIREMENT FORMULA.

A. This component of the formula is broken down into the following sections in Exhibit AH-6:

- Return on TIC (line 1 through 8)
- Operating Expenses (lines 10 and 12)
- Income and Other Taxes (lines 13 through 26)
- Revenue Credits (lines 27 through 30)

Further details on this calculation are discussed below.

Q. WHAT ARE THE "APPROVED TRANSMISSION CHARGES" OR "ATC" IN THE FORMULA?

A. ATC are wholesale transmission charges allocated to Texas customers that have been approved by the FERC and that the Company is not recovering through other retail or wholesale rates. These transmission charges are the cost of purchasing transmission from other utilities in order to bring EPE's remote generation and purchased power to its retail customers including its Texas customers. They are charged to FERC Account 565, Transmission of Electricity by Others.

Q. HOW IS THE "ALLOC" ELEMENT OF EPE'S REVENUE REQUIREMENT CALCULATION DETERMINED?

A. Texas retail allocation of transmission revenue requirements are determined in EPE's rate case schedules in this proceeding. Schedules P-2, P-3, and P-10 are presented at the Texas jurisdictional level.

Q. HOW DOES THE TCRF RULE DEFINE TRANSMISSION INVESTED COSTS?

A. 16 TAC § 25.239(b)(2) defines "transmission invested costs" ("TIC") as the "net change in the electric utility's transmission investment costs including additions, upgrades, and retirements as booked in FERC Accounts 350-359, and accumulated depreciation." This component of the formula is seen on line 4 of Exhibit AH-6.

Q. HOW DID YOU CALCULATE THE ADIT AMOUNT USED IN THE CALCULATION OF THE TIC?

A. The Texas jurisdictional allocation of ADIT is reflected on Schedule P-3. As shown on page 2 of Exhibit AH-6. This balance is allocated to the transmission function to produce the transmission related ADIT. The transmission balance of ADIT is seen on page 1, line 5 of Exhibit AH-6.

Q. WHAT IS THE WACC BEING USED TO CALCULATE THE RETURN ON TIC?

A. The Company's requested WACC of 7.985% is used to calculate return on TIC as shown on line 7 of Exhibit AH-6.

Q. PLEASE DESCRIBE THE CALCULATION OF EPE'S TRANSMISSION INVESTMENT-RELATED EXPENSES IN MORE DETAIL.

A. As indicated in the TCRF Rule, these include: "investment-related expenses such as income taxes, other associated taxes, depreciation, and transmission–related miscellaneous revenue credits, but [do] not includ[e] operation and maintenance expenses or administrative expenses". Depreciation expense for transmission plant is shown on line 10 and property taxes are shown on line 12 of Exhibit AH-6.

Q. HOW DID YOU CALCULATE THE INCOME TAX AND OTHER ASSOCIATED TAXES USED IN THE CALCULATION OF THE TIC?

A. Income taxes (federal and state) are calculated in lines 13 through 21 of Exhibit AH-6. Taxable Income is multiplied by the income tax factor to produce income taxes before credits. Thereafter, amortization of excess deferred income tax is added to this balance to produce the income tax expense.

Revenue-related taxes are calculated in lines 22 through 26 of Exhibit AH-6. The sum of the revenue requirement at that point grossed up by the revenue tax gross up factor then multiplied times the Texas revenue-related tax rates.

Q. WHAT ARE THE "TRANSMISSION-RELATED MISCELLANEOUS REVENUE CREDITS" REFERRED TO IN 16 TAC § 25.239(e)?

A. Transmission–related miscellaneous revenue credits are revenues EPE received from the sale of wholesale transmission service under its Open Access Transmission Tariff approved by the FERC. These transmission revenues reduce the revenue requirement that would otherwise be collected from retail customers. This Texas jurisdictional allocation of transmission revenues is seen on line 30 of Exhibit AH-6.

Q. WHAT IS THE "REVREQT" COMPONENT AMOUNT OF THE REVENUE REQUIREMENT FORMULA?

A. After having worked through each of the sections of Exhibit AH-6, the revreqt amount of $15,579,431 is calculated on line 31.

Q. DOES EPE HAVE ANY VARIABLE-APPROVED TRANSMISSION CHARGES ("ATC") TO INCLUDE IN THE BASELINE CALCULATION?

A. Yes. EPE purchases transmission wheeling from other utilities to deliver power from Palo Verde and for power it purchases to serve retail customers. Transmission wheeling expense charged to FERC Account 565, Transmission of Electricity by Others, is allocated to Texas and reflected as ATC on line 33 of Exhibit AH-6.

Q. HOW IS THE TCRF REVENUE REQUIREMENT (RR) CALCULATED?

A. As previously stated, the RR is calculated as:

RR = [revreqt + ATC]*ALLOC

The numbers shown in Exhibit AH-6 are already presented at the Texas jurisdictional level. Therefore, the final RR of $20,934,779 is calculated on line 34 of Exhibit AH-6 by adding the revreqt of $15,579,431 (line 31) plus the ATC of $5,355,348 (line 33).

Q. WHAT IS THE "CLASSALLOC" ELEMENT OF THE TCRF CALCULATION FOR EPE?

A. As described by the TCRF Rule, 16 TAC § 25.239(d), ClassALLOC is the customer class allocation factors used to allocate the transmission revenue requirement in the utility's most recent base-rate case. The rate class allocators are shown at the bottom of page 1 of Exhibit AH-6 (lines 43 through 61).

Q. WHAT TCRF REVENUE REQUIREMENT IS EPE ASKING THE COMMISSION TO SET FOR PURPOSES OF ESTABLISHING A TCRF BASELINE?

A. The total baseline amount calculated above is $20,934,779 as shown on line 61 (column RR) of Exhibit AH-6.

Q DOES EPE INTEND TO FILE A TCRF RATE RIDER IN THIS PROCEEDING?

A. No. EPE seeks approval of a new TCRF baseline in this proceeding allowing for future cost recovery "for reasonable and necessary costs for transmission infrastructure improvement and changes in wholesale rates that are appropriately allocated to Texas retail customers." Any future rate rider filing will be made pursuant to 16 TAC § 25.239(d) and will calculate the incremental transmission revenue requirement and the associated TCRF rates by customer rate class. Revising the baseline in this case will allow EPE to evaluate whether a TCRF proceeding in the future is warranted.

IX. Generation Cost Recovery Rider

Q. WHAT IS A GENERATION COST RECOVERY RIDER?

A. Generation Cost Recovery Rider ("GCRR") is a rate mechanism approved by the Texas Legislature that allows an electric utility to recover its investment in a power generation facility outside of a base-rate proceeding.

Q. HAS THE COMMISSION ADOPTED A RULE TO IMPLEMENT A GCRR?

A. Yes. The Commission has adopted 16 TAC § 25.248 ("GCRR Rule") to implement a GCRR as described by PURA § 36.2135.

Q. WHAT RELIEF IS EPE SEEKING IN THIS PROCEEDING WITH RESPECT TO THE ESTABLISHMENT OF THE GCRR?

A. In this proceeding, EPE is establishing the GCRR baseline values for the components that are used for a subsequent implementation of the GCRR. Accordingly, with the approval and implementation of base rates reflecting EPE's Test Year adjusted generation costs, the GCRR rates will also be set to zero.

Q. WHAT BASELINE VALUES ARE REQUIRED BY THE SUBSTANTIVE RULE?

A. The GCRR Rule requires the following baseline values based on those utilized to establish rates in the Company's most recent base-rate proceeding.

(1) TRAF – the Texas retail jurisdictional production allocation factor,

(2) $BD_{RC\text{-}CLASS}$ – the rate class billing determinants used to establish generation base rates with energy-based billing determinants used for those rate classes that do not include any demand charges and demand-based billing determinants for those rate classes that include rate-demand charges,

(3) ROR_{RC} – the after-tax rate of return approved by the Commission, and

(4) $ALLOC_{RC\text{-}CLASS}$ – the rate class allocation factor values.

Q. HAVE YOU PREPARED AN EXHIBIT THAT SETS FORTH THE BASELINE

[5] Two sections number 36.213 were added by the 86th Texas Legislature.

VALUES DESCRIBED ABOVE?

A. Yes. Exhibit AH-7 sets forth the GCRR baseline values described above that can be utilized by EPE in a subsequent GCRR proceeding, which are derived from information included in this base rate case.

X. Summary and Conclusion

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. The JCOS for the test year ended December 31, 2020, results in a total revenue requirement of $751.6 million and a base revenue requirement of $578.7 million for the Texas jurisdiction. The base revenue deficiency is $41.8 million.

The CCOS shows the assignment of the revenue requirements discussed above to each rate class. Exhibit AH-4 summarizes the CCOS and the resulting rate increase required to achieve an equalized rate of return across rate classes. The resulting firm base revenue requirements (net of non-firm revenues) for each class are shown on line 4 of Schedule P-1.04.

The DEC study results in the assignment of the $574.5 million firm base revenue requirement (net of non-firm revenues) to each DEC component by Texas rate class. The summary of these results can be seen on Schedule P-6.

Finally, I established the baseline revenue requirements and values for potential future filings of the DCRF, TCRF, and GCRR rates.

Q. IN YOUR OPINION, ARE THE ALLOCATION METHODS AND THE RESULTS OF THE ALLOCATIONS EMPLOYED IN EPE'S COST-OF-SERVICE STUDIES FAIR AND REASONABLE?

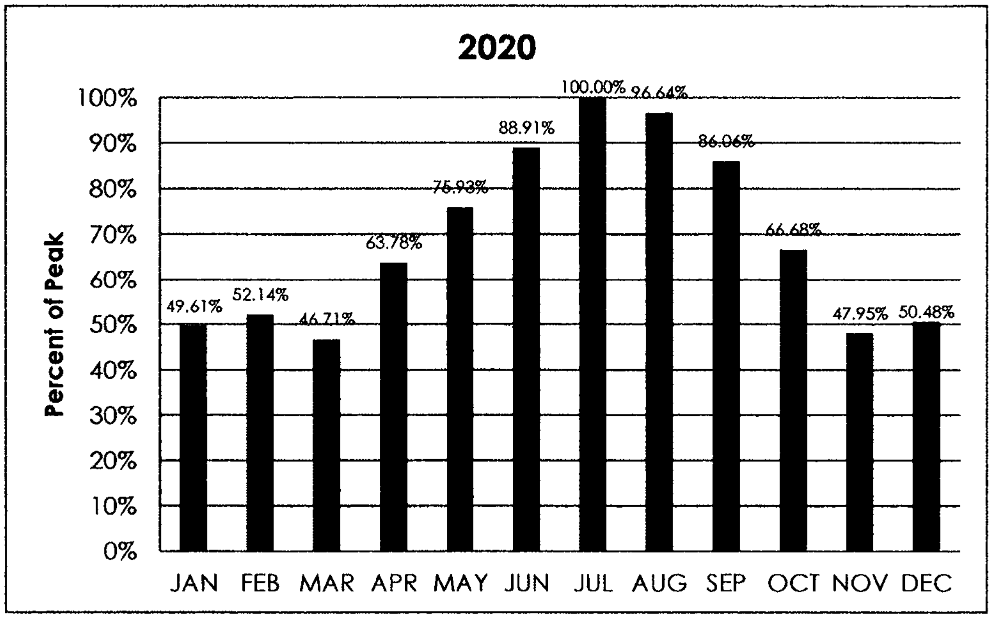
A. Yes. The allocation methods employed in EPE's cost-of-service studies are fair and reasonable and accurately present the costs to serve each jurisdiction and rate class. Furthermore, the methods that have been employed in conducting the cost-of-service studies utilize well-reasoned methods which are commonly employed in the electric utility industry.

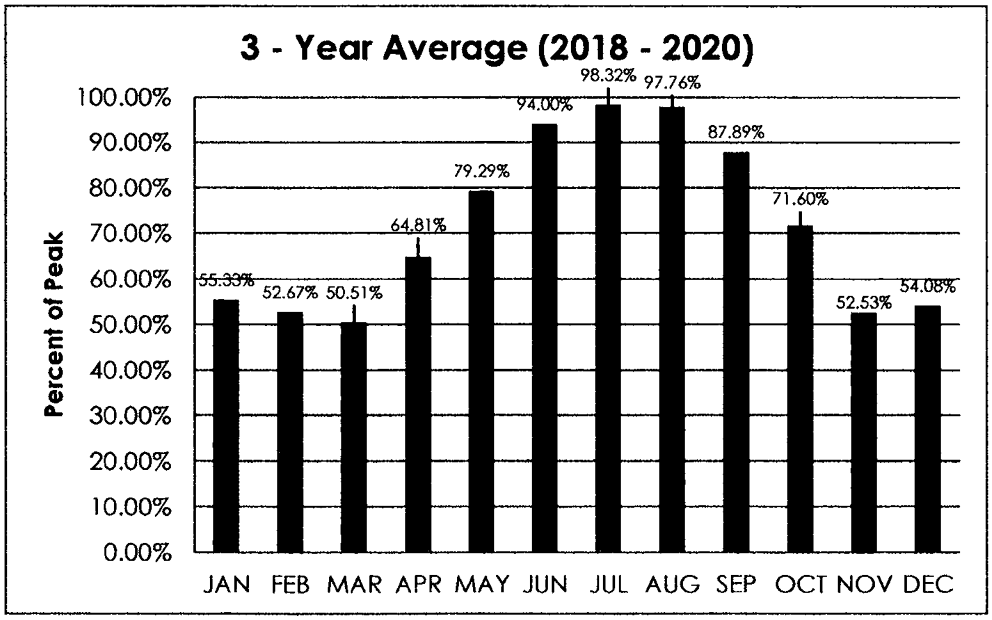
Q. DOES THIS CONCLUDE YOUR TESTIMONY?

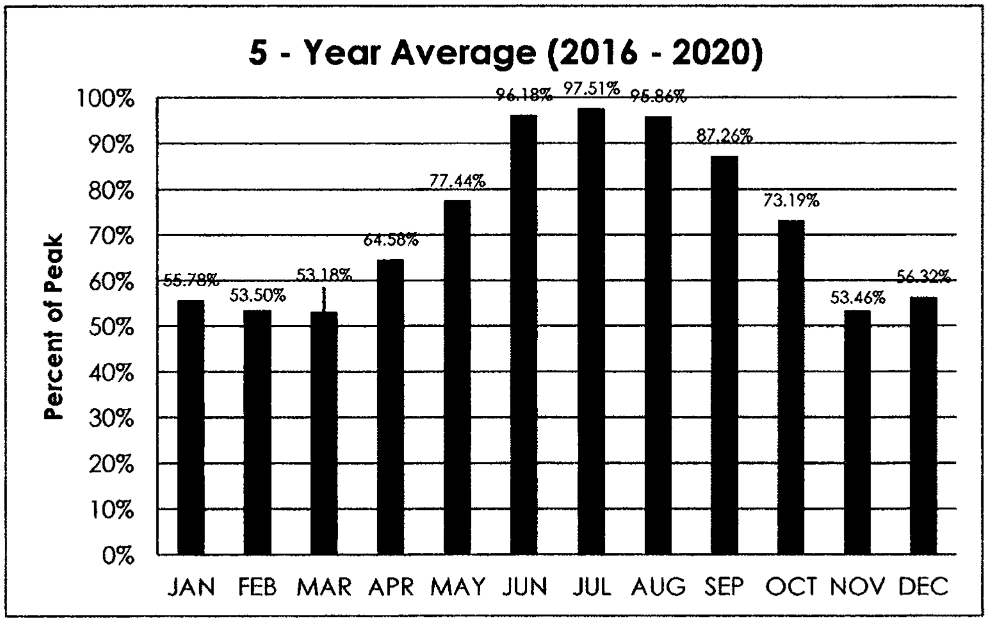
A. Yes, it does.

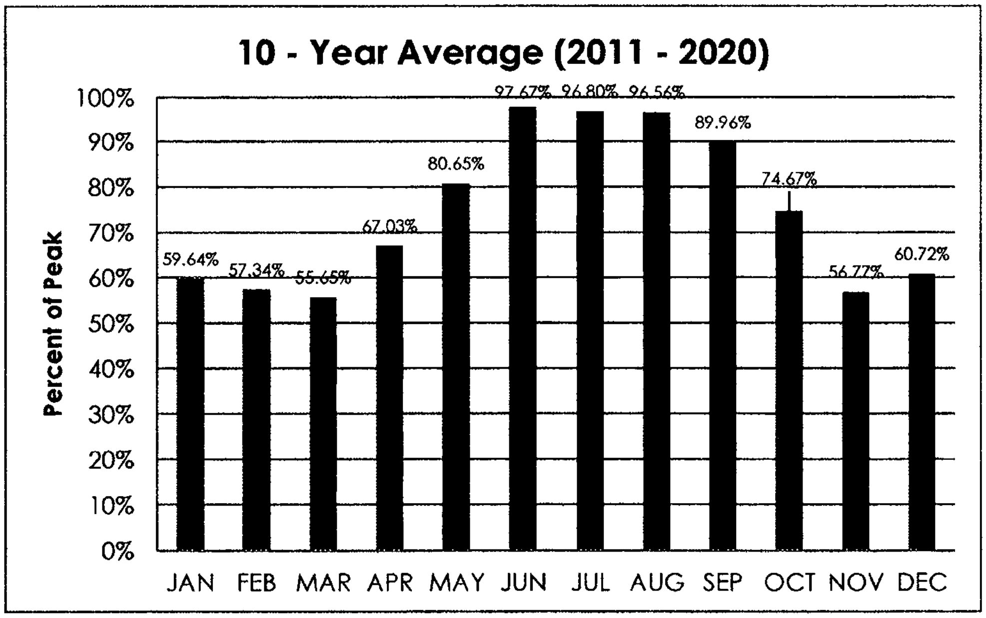
SCHEDULES SPONSORED BY A. HERNANDEZ

Schedule	Description	Sponsorship
A-1	COST OF SERVICE - TEXAS RETAIL	Sponsor
B-1.1	TEXAS RETAIL	Sponsor
O-5	VARIABILITY OF AVERAGE FUEL COSTS WITH KWH SALES	Sponsor
P	CLASS COST OF SERVICE ANALYSIS	Sponsor
P-1.1	PROPOSED RATE SCHEDULES / PROPOSED RATE CLASSES	Sponsor
P-1.2	EXISTING RATE SCHEDULES / PROPOSED RATE CLASSES	Sponsor
P-1.3	EXISTING RATE SCHEDULES / EXISTING RATE CLASSES	Sponsor
P-1.4	PROPOSED RATE SCHEDULES / EXISTING RATE CLASSES	Sponsor
P-1.5	FINANCIAL DATA FOR NON-INVESTOR-OWNED UTILITIES	Sponsor
P-2	ALLOCATION OF EXPENSES TO PROPOSED RATE CLASSES	Sponsor
P-3	ALLOCATION OF RATE BASE TO PROPOSED RATE CLASSES	Sponsor
P-4	SEPARATION OF EXPENSES	Sponsor
P-5	SEPARATION OF RATE BASE	Sponsor
P-6	UNIT COST ANALYSIS	Sponsor
P-7	ALLOCATION FACTORS	Sponsor
P-8	CLASSIFICATION FACTORS	Sponsor
P-10	PAYROLL EXPENSE DISTRIBUTION	Sponsor
P-11	DISTRIBUTION PLANT STUDY	Sponsor
P-12	SUPPORT FOR PRODUCTION ALLOCATION METHODOLOGY	Sponsor
P-13	SUMMARY OF CHANGES IN ALLOCATION FACTORS	Sponsor
Q-2	POWER COST RECOVERY	Sponsor


2020
Percent of Peak
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
49.61%
52.14%
46.71%
63.78%
75.93%
88.91%
100.00%
96.64%
86.06%
66.68%
47.95%
50.48%
JAN FEB MAR APR MAY JUN JUL AUG SEP OCT NOV DEC


3 - Year Average (2018 - 2020)
Percent of Peak
100.00%
90.00%
80.00%
70.00%
60.00%
50.00%
40.00%
30.00%
20.00%
10.00%
0.00%
55.33%
52.67%
50.51%
64.81%
79.29%
94.00%
98.32%
97.76%
87.89%
71.60%
52.53%
54.08%
JAN FEB MAR APR MAY JUN JUL AUG SEP OCT NOV DEC


5 - Year Average (2016 - 2020)
Percent of Peak
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
55.78%
53.50%
53.18%
64.58%
77.44%
96.18%
97.51%
95.86%
87.26%
73.19%
53.46%
56.32%
JAN FEB MAR APR MAY JUN JUL AUG SEP OCT NOV DEC


10 - Year Average (2011 - 2020)
Percent of Peak
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
59.64%
57.34%
55.65%
67.03%
80.65%
97.67%
96.80%
96.56%
89.96%
74.67%
56.77%
60.72%
JAN FEB MAR APR MAY JUN JUL AUG SEP OCT NOV DEC

EL PASO ELECTRIC COMPANY
2021 TEXAS RATE CASE
JURISDICTIONAL COST OF SERVICE STUDY SUMMARY
(000's)

Revenues and Expenses

	Total Company Test Year Total	Texas Test Year Total	Other Test Year Total
Operating Revenues	967,939	751,632	216,307
Operation & Maintenance Expenses			
Fuel & Purchased Power	199,908	147,436	52,472
Production (Excl. Fuel & Purchased Power	145,625	116,625	29,000
Transmission	23,792	18,928	4,864
Distribution	26,230	19,733	6,497
Customer Services	19,362	15,530	3,831
Administration & General	100,679	72,323	28,356
Other	83	34	49
Total Operation & Maintenance Expenses	515,678	390,610	125,068
Depreciation & Amortization			
Production	61,556	49,427	12,129
Transmission	9,421	7,498	1,923
Distribution	31,521	23,107	8,414
General Plant	16,005	12,636	3,369
Intangible Amortization	8,142	6,421	1,721
Total Depreciation & Amortization	126,644	99,089	27,555
Taxes Other Than Income Taxes	76,885	68,512	8,374
Regulatory Debits and Credits	5,020	2,986	2,034
Decommissioning and Accretion Expense	138	112	26
Pre-tax Expenses	724,365	561,309	163,056
Income Taxes			
State	4,506	3,529	977
Federal	30,572	23,584	6,988
Total Income Taxes	35,078	27,113	7,965
Total Operating Expenses	759,443	588,422	171,021
Operating Income	208,497	163,210	45,286
Total Cost of Service	967,939	751,632	216,307
Excluding Fuel & Purchased Power and Other Operating Revenue	248,128	172,926	75,201
Less: Non-Fuel Base Revenues @ Present Rates	665,230	536,888	128,342
Non-Fuel Base Revenue Deficiency @ Equalized Rate of Return	54,582	41,818	12,765
Percent Increase Required	8.2%	7.8%	9.9%

EL PASO ELECTRIC COMPANY
2021 TEXAS RATE CASE
JURISDICTIONAL COST OF SERVICE STUDY SUMMARY
(000's)

Rate Base and Return

	Total Company Test Year Total	Texas Test Year Total	Other Test Year Total
Plant In Service			
Intangible	119,028	93,956	25,071
Production	2,330,454	1,875,351	455,103
Transmission	555,283	441,950	113,333
Distribution	1,427,591	1,050,173	377,418
General Plant	258,130	203,780	54,350
Total Plant In Service	4,690,486	3,665,210	1,025,276
Accumulated Depreciation & Amortization			
Intangible	(78,414)	(61,463)	(16,951)
Production	(746,857)	(604,613)	(142,245)
Transmission	(242,771)	(193,221)	(49,549)
Distribution	(411,153)	(287,838)	(123,315)
General Plant	(97,020)	(76,630)	(20,389)
Total Accumulated Depr & Amort.	(1,576,215)	(1,223,766)	(352,449)
Net Plant In Service	3,114,271	2,441,445	672,826
Additions (Deductions) to Rate Base			
Working Capital	78,554	62,124	16,430
Other Additions	171,864	129,511	42,353
Other Deductions	(753,664)	(589,178)	(164,486)
Rate Base	2,611,025	2,043,902	567,123
Operating Income	208,497	163,210	45,286
Rate of Return	7.985%	7.985%	7.985%

Totals may not tie to other schedules due to rounding.

EL PASO ELECTRIC COMPANY
2021 TEXAS RATE CASE FILING
CLASS COST OF SERVICE STUDY SUMMARY
(000's)

	Texas Test Year Total	Rate 01 Residential	Rate 02 Small General Service	Rate 07 Recreational Lighting	Rate 08 Street Lighting	Rate 09 Traffic Signals	Rate 11 Municipal Pumping	Rate 15 Electric Refining	Rate 22 Irrigation Service
Operating Revenues	**751,632**	402,303	38,092	713	3,970	151	14,648	4,129	678
Operation & Maintenance Expenses									
Fuel & Purchased Power	**147,436**	58,764	6,418	86	845	49	4,014	1,768	91
Production (Excl. Fuel & Purchased Power)	**116,625**	57,397	5,462	51	484	29	2,544	696	96
Transmission	**18,928**	10,309	900	4	7	3	311	102	18
Distribution	**19,733**	12,454	1,115	59	364	2	347	0	23
Customer Services	**15,530**	13,071	1,458	11	8	2	22	0	9
Administration & General	**72,323**	44,177	4,498	81	464	12	1,110	234	65
Other	**34**	30	3	0	0	0	0	0	0
Total Operation & Maintenance Expenses	**390,610**	196,202	19,853	292	2,173	97	8,348	2,800	302
Depreciation & Amortization									
Production	**49,427**	27,029	2,337	12	114	8	800	257	47
Transmission	**7,498**	4,141	356	0	0	1	120	39	7
Distribution	**23,107**	14,212	1,201	77	304	2	468	0	31
General Plant	**12,636**	7,721	787	15	86	2	196	40	11
Intangible Amortization	**6,421**	3,889	389	8	44	1	101	21	6
Total Depreciation & Amortization	**99,089**	56,993	5,070	112	549	15	1,684	356	103
Taxes Other Than Income Taxes	**68,512**	38,094	3,448	64	345	12	1,232	308	66
Regulatory Debits and Credits	**2,986**	1,773	174	3	17	1	47	11	3
Decommissioning and Accretion Expense	**112**	61	5	0	0	0	2	1	0
Pre-tax expenses	**561,309**	293,123	28,551	471	3,085	124	11,313	3,476	474
Income Taxes									
State	**3,529**	2,024	177	4	17	1	62	12	4
Federal	**23,584**	13,603	1,197	31	115	3	414	78	25
Total Income Taxes	**27,113**	15,627	1,374	36	131	4	475	90	29
Total Expenses	**588,422**	308,750	29,925	507	3,216	128	11,788	3,566	503
Operating Income	**163,210**	93,553	8,167	207	754	23	2,860	563	176
Total Cost of Service	**751,632**	402,303	38,092	713	3,970	151	14,648	4,129	678
Excluding Fuel & Purchased Power and Other Operating Revenue	**172,926**	73,752	7,755	97	891	52	4,384	1,870	115
Less: Non-Fuel Base Revenues @ Present Rates	**536,888**	275,944	33,518	463	4,047	96	10,169	1,852	427
Non-Fuel Base Revenue Deficiency @ Equalized Rate of Return	**41,818**	52,607	(3,182)	154	(968)	3	95	407	136
Percent Increase Required	**7.8%**	19.1%	-9.5%	33.2%	-23.9%	3.6%	0.9%	22.0%	31.7%

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EL PASO ELECTRIC COMPANY
2021 TEXAS RATE CASE FILING
CLASS COST OF SERVICE STUDY SUMMARY
(000's)

	Rate 24 General Service	Rate 25 Large Power	Rate 26 Petroleum Refinery	Rate 28 Area Lighting	Rate 30 Electric Furnace	Rate 31 Military Reservation	Rate 34 Cotton Gin	Rate 41 City and County	Rider WH Water Heating
Operating Revenues	154,234	54,908	22,165	3,301	5,661	23,095	219	22,387	978
Operation & Maintenance Expenses									
Fuel & Purchased Power	34,120	15,817	8,561	629	4,073	7,485	37	4,559	120
Production (Excl Fuel & Purchased Power)	26,429	9,797	4,442	360	404	4,601	22	3,742	71
Transmission	4,045	1,331	545	6	68	678	1	596	5
Distribution	3,336	898	0	476	0	0	16	537	105
Customer Services	774	64	0	36	0	0	1	44	30
Administration & General	12,444	3,958	1,364	212	146	1,547	19	1,833	160
Other	1	0	0	0	0	0	0	0	0
Total Operation & Maintenance Expenses	81,149	31,865	14,913	1,719	4,691	14,311	96	11,311	491
Depreciation & Amortization									
Production	10,442	3,423	1,391	85	169	1,733	5	1,557	19
Transmission	1,584	515	208	0	26	262	0	237	2
Distribution	4,434	1,199	0	365	0	0	22	713	78
General Plant	2,173	691	234	38	25	263	4	320	30
Intangible Amortization	1,131	359	120	19	13	137	2	167	15
Total Depreciation & Amortization	19,764	6,186	1,952	507	233	2,395	32	2,994	145
Taxes Other Than Income Taxes	13,957	4,629	1,690	274	298	1,918	19	2,071	85
Regulatory Debits and Credits	545	175	63	8	7	73	1	80	6
Decommissioning and Accretion Expense	24	8	3	0	0	4	0	4	0
Pre-tax expenses	115,438	42,862	18,621	2,509	5,230	18,701	148	16,459	726
Income Taxes									
State	719	223	66	15	8	82	1	110	5
Federal	4,770	1,476	424	100	51	524	9	729	34
Total Income Taxes	5,488	1,699	490	115	59	606	10	839	38
Total Expenses	120,926	44,562	19,111	2,624	5,289	19,306	158	17,298	765
Operating Income	33,308	10,346	3,054	677	372	3,789	61	5,089	213
Total Cost of Service	154,234	54,908	22,165	3,301	5,661	23,095	219	22,387	978
Excluding Fuel & Purchased Power and Other Operating Revenue	39,114	17,344	9,108	658	4,140	8,173	40	5,265	167
Less: Non-Fuel Base Revenues @ Present Rates	125,888	36,243	11,080	2,933	1,206	13,156	133	19,258	476
Non-Fuel Base Revenue Deficiency @ Equalized Rate of Return	(10,768)	1,321	1,976	(290)	315	1,766	45	(2,136)	335
Percent Increase Required	-8.6%	3 6%	17.8%	-9.9%	26 1%	13 4%	34.0%	-11 1%	70 5%

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EL PASO ELECTRIC COMPANY
2021 TEXAS RATE CASE FILING
CLASS COST OF SERVICE STUDY SUMMARY
(000's)

	Texas Test Year Total	Rate 01 Residential	Rate 02 Small General Service	Rate 07 Recreational Lighting	Rate 08 Street Lighting	Rate 09 Traffic Signals	Rate 11 Municipal Pumping	Rate 15 Electric Refining	Rate 22 Irrigation Service
Plant In Service									
Intangible	**93,956**	62,971	6,950	120	590	15	1,142	200	82
Production	**1,875,351**	1,025,253	88,657	453	4,440	309	30,367	9,752	1,796
Transmission	**441,950**	244,078	20,998	0	0	57	7,045	2,289	428
Distribution	**1,050,173**	646,860	54,663	3,562	14,455	110	21,350	1	1,391
General Plant	**203,780**	124,520	12,698	241	1,393	34	3,162	641	185
Total Plant In Service	**3,665,210**	2,103,682	183,966	4,376	20,878	526	63,065	12,883	3,882
Accumulated Depreciation & Amortization									
Intangible	**(61,463)**	(37,941)	(3,758)	(94)	(569)	(9)	(973)	(158)	(59)
Production	**(604,613)**	(329,968)	(28,559)	(171)	(1,675)	(103)	(9,816)	(3,146)	(578)
Transmission	**(193,221)**	(106,711)	(9,180)	0	0	(25)	(3,080)	(1,001)	(187)
Distribution	**(287,838)**	(180,092)	(15,521)	(911)	(6,529)	(29)	(5,341)	(0)	(358)
General Plant	**(76,630)**	(46,825)	(4,775)	(91)	(524)	(13)	(1,189)	(241)	(70)
Total Accumulated Depr & Amort.	**(1,223,766)**	(701,538)	(61,793)	(1,267)	(9,297)	(180)	(20,399)	(4,547)	(1,251)
Net Plant In Service	**2,441,445**	1,402,144	122,172	3,110	11,581	346	42,666	8,336	2,630
Additions (Deductions) to Rate Base									
Working Capital	**62,124**	35,147	3,108	80	400	10	1,112	231	65
Other Additions	**129,511**	75,345	6,743	175	719	19	2,238	419	137
Other Deductions	**(589,178)**	(341,067)	(29,746)	(778)	(3,258)	(83)	(10,204)	(1,935)	(632)
Rate Base	**2,043,902**	1,171,569	102,277	2,587	9,443	291	35,812	7,051	2,200
Operating Income	**163,210**	93,553	8,167	207	754	23	2,860	563	176
Rate of Return	**7.985%**	7 985%	7 985%	7.985%	7.985%	7.985%	7 985%	7 985%	7.985%

Totals may not tie to other schedules due to rounding

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EL PASO ELECTRIC COMPANY
2021 TEXAS RATE CASE FILING
CLASS COST OF SERVICE STUDY SUMMARY
(000's)

	Rate 24 General Service	Rate 25 Large Power	Rate 26 Petroleum Refinery	Rate 28 Area Lighting	Rate 30 Electric Furnace	Rate 31 Military Reservation	Rate 34 Cotton Gin	Rate 41 City and County	Rider WH Water Heating
Plant In Service									
Intangible	13,034	3,802	1,133	268	129	1,321	24	1,920	257
Production	396,183	129,889	52,786	3,303	6,412	65,753	201	59,059	738
Transmission	93,390	30,370	12,241	0	1,517	15,453	5	13,965	113
Distribution	203,080	55,118	4	12,487	1	5	990	32,742	3,356
General Plant	35,044	11,137	3,768	615	400	4,237	57	5,162	486
Total Plant In Service	740,732	230,315	69,931	16,672	8,459	86,769	1,277	112,848	4,949
Accumulated Depreciation & Amortization									
Intangible	(10,562)	(3,254)	(923)	(219)	(100)	(1,047)	(23)	(1,583)	(190)
Production	(127,724)	(41,932)	(17,064)	(1,246)	(2,066)	(21,209)	(75)	(19,030)	(252)
Transmission	(40,830)	(13,278)	(5,352)	0	(663)	(6,756)	(2)	(6,105)	(49)
Distribution	(51,355)	(13,571)	(2)	(4,610)	(1)	(3)	(244)	(8,200)	(1,071)
General Plant	(13,178)	(4,188)	(1,417)	(231)	(151)	(1,593)	(22)	(1,941)	(183)
Total Accumulated Depr & Amort.	(243,650)	(76,222)	(24,758)	(6,306)	(2,980)	(30,608)	(365)	(36,860)	(1,745)
Net Plant In Service	497,082	154,093	45,173	10,366	5,479	56,161	912	75,988	3,204
Additions (Deductions) to Rate Base									
Working Capital	12,657	4,025	1,269	310	178	1,507	24	1,914	89
Other Additions	25,655	7,942	2,299	572	273	2,812	50	3,910	203
Other Deductions	(118,276)	(36,496)	(10,495)	(2,766)	(1,272)	(13,034)	(225)	(18,088)	(823)
Rate Base	417,118	129,564	38,246	8,483	4,658	47,447	760	63,725	2,672
Operating Income	33,308	10,346	3,054	677	372	3,789	61	5,089	213
Rate of Return	7.985%	7.985%	7.985%	7.985%	7.985%	7.985%	7.985%	7.985%	7.985%

Totals may not tie to other schedules due to rounding

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Line	Description	Total Texas Distribution Function	Reference
1	**Distribution Invested Capital (DIC)**		
2	Distribution Gross Plant In Service	$ 1,090,792,394	L35
3	Distribution Accum Depr (Plant ACCT 360-374)	$ (287,838,113)	Schedule P-3
4	Distribution Accum Amort (Plant ACCT 303)	$ (25,653,349)	Schedule P-3 Dist related amount (plus share of general)
5	Distribution Accum Depr (Plant ACCT 391)	$ (5,327,119)	Schedule P-3* LABOR
6	Distribution Accum Depr (Plant ACCT 397)	$ (3,161,508)	Schedule P-3* LABOR
7	Accumulated Deferred Income Taxes	$ (126,867,295)	Schedule P-3
8	Current Net Distribution Invested Capital (DIC_C)	$ 641,945,010	L2+L3+L4+L5+L6+L7
9	Rate of Return on Invested Capital (ROR)	7.985%	Schedule K-1
10	Return on Distribution Invested Capital	$ 51,260,850	L8*L9
11	**Distribution Expenses**		
12	Distribution Depreciation Expense ($DEPR_C$)	$ 26,698,250	Schedule P-2
13	Property taxes	$ 5,080,118	Schedule P-2
14	**Federal Income Tax Expense**		
15	Return	$ 51,260,850	L10
16	Interest synchronization	$ (17,539,478)	L8* Interest Sync Rate
17	Permanent and flow through differences	$ 1,444,849	(Federal Perms + Excess Deferred Taxes) * L39
18	Taxable income	$ 35,166,221	L15+L16+L17
19	Income tax factor	0.265823	
20	Taxes before credits	$ 9,347,983	L18*L19
21	Excess deferred income taxes	$ (944,851)	Schedule P-2 * L39
22	Federal Income Tax Expense	$ 8,403,132	L20+L21
23	**Revenue Related Taxes Excl. Municipal Franchise Fees**		
24	Revenue Requirements before revenue taxes	$ 91,442,350	L10+L12+L13+L22
25	Revenue tax gross up factor	1 050385214	
26	Revenue Requirements before credits	$ 96,049,692	L24*L25
27	Texas revenue tax rate excluding municipal franchise fees	0 013211834	
28	Revenue taxes excluding municipal franchise fees	$ 1,268,993	L26*27
29	Total Distribution Baseline Revenue Requirement (DISTREV)	$ 92,711,343	L24+L28
30	**Development of Gross Distribution Plant Allocator**		
31	Distribution Plant In Service (Plant Acct 360-374)	$ 1,050,173,478	Schedule P-3
32	Intangible Distribution Plant (Plant Acct 303)	$ 25,950,882	Schedule P-3, See WP
33	General Plant (Plant Acct 391)	$ 7,003,900	P-3 Acct 391 x Dist % of LABOR
34	General Plant (Plant Acct 397)	$ 7,664,133	P-3 Acct 399 x Dist % of LABOR
35	Distribution Gross Plant In Service	$ 1,090,792,394	L31+L32+L33+L34
36			
37	Gross Plant In Service	$ 3,665,210,259	Schedule P-3
38	Gross Distribution Plant Allocator	28.65%	L31/L37
39	Net Distribution Plant Allocator	31.22%	P-3

40	**Development of Distribution Rate Class Allocators**	Balances	$ALLOC_{CLASS}$	$DISTREV_{RC\text{-}CLASS}$	Reference (Balances column)	Reference (DISTREV Column)
41	Rate 01 Residential	$ 646,860,483			Schedule P-3	
42	Rate 01 Residential Intangible	$ 16,968,759			Line 32 * DISTLABOR	
43	Rate 01 Residential General Plant 391	$ 4,579,709			Line 33 * DISTLABOR	
44	Rate 01 Residential General Plant 397	$ 5,011,422	61.7368%	$ 57,237,021	Line 34 * DISTLABOR	$L29*ALLOC_{CLASS}$
45	Rate 02 Small General Service	$ 54,663,028			Schedule P-3	
46	Rate 02 Small General Service Intangible	$ 1,546,150			Line 32 * DISTLABOR	
47	Rate 02 Small General Service General Plant 391	$ 417,291			Line 33 * DISTLABOR	
48	Rate 02 Small General Service General Plant 397	$ 456,628	5.2332%	$ 4,851,749	Line 34 * DISTLABOR	$L29*ALLOC_{CLASS}$
49	Rate 07 Recreational Lighting	$ 3,561,867			Schedule P-3	
50	Rate 07 Recreational Lighting Intangible	$ 76,182			Line 32 * DISTLABOR	
51	Rate 07 Recreational Lighting General Plant 391	$ 20,561			Line 33 * DISTLABOR	
52	Rate 07 Recreational Lighting General Plant 397	$ 22,499	0 3375%	$ 312,874	Line 34 * DISTLABOR	$L29*ALLOC_{CLASS}$
53	Rate 08 Street Lighting	$ 14,455,484			Schedule P-3	
54	Rate 08 Street Lighting Intangible	$ 505,661			Line 32 * DISTLABOR	
55	Rate 08 Street LightingGeneral Plant 391	$ 136,473			Line 33 * DISTLABOR	
56	Rate 08 Street LightingGeneral Plant 397	$ 149,338	1.3978%	$ 1,295,907	Line 34 * DISTLABOR	$L29*ALLOC_{CLASS}$
57	Rate 09 Traffic Signals	$ 109,578			Schedule P-3	
58	Rate 09 Traffic Signals Intangible	$ 2,587			Line 32 * DISTLABOR	
59	Rate 09 Traffic Signals General Plant 391	$ 698			Line 33 * DISTLABOR	
60	Rate 09 Traffic Signals General Plant 397	$ 764	0.0104%	$ 9,658	Line 34 * DISTLABOR	$L29*ALLOC_{CLASS}$
61	Rate 11-TOU Municipal Pumping	$ 21,349,909			Schedule P-3	
62	Rate 11-TOU Municipal Pumping Intangible	$ 437,642			Line 32 * DISTLABOR	
63	Rate 11-TOU Municipal Pumping General Plant 391	$ 118,116			Line 33 * DISTLABOR	
64	Rate 11-TOU Municipal Pumping General Plant 397	$ 129,250	2 0201%	$ 1,872,846	Line 34 * DISTLABOR	$L29*ALLOC_{CLASS}$

2021 TEXAS RATE CASE FILING
DISTRIBUTION BASELINE REVENUE REQUIREMENT

			$ALLOC_{CLASS}$	$DISTREV_{RC\text{-}CLASS}$	Reference	
65	**Development of Distribution Rate Class Allocators**					
66	Rate 15 Electric Refining	$ 645			Schedule P-3	
67	Rate 15 Electric Refining Intangible	$ 82			Line 32 * DISTLABOR	
68	Rate 15 Electric Refining General Plant 391	$ 22			Line 33 * DISTLABOR	
69	Rate 15 Electric Refining General Plant 397	$ 24	0 0001%	$ 66	Line 34 * DISTLABOR	L29*$ALLOC_{CLASS}$
70	Rate 22 Irrigation Service	$ 1,390,954			Schedule P-3	
71	Rate 22 Irrigation Service Intangible	$ 30,179			Line 32 * DISTLABOR	
72	Rate 22 Irrigation Service General Plant 391	$ 8,145			Line 33 * DISTLABOR	
73	Rate 22 Irrigation Service General Plant 397	$ 8,913	0 1318%	$ 122,238	Line 34 * DISTLABOR	L29*$ALLOC_{CLASS}$
74	Rate 24 General Service	$ 203,080,230			Schedule P-3	
75	Rate 24 General Service Intangible	$ 4,237,447			Line 32 * DISTLABOR	
76	Rate 24 General Service General Plant 391	$ 1,143,647			Line 33 * DISTLABOR	
77	Rate 24 General Service General Plant 397	$ 1,251,455	19 2257%	$ 17,824,431	Line 34 * DISTLABOR	L29*$ALLOC_{CLASS}$
78	Rate 25 Large Power	$ 55,117,745			Schedule P-3	
79	Rate 25 Large Power Intangible	$ 1,128,514			Line 32 * DISTLABOR	
80	Rate 25 Large Power General Plant 391	$ 304,575			Line 33 * DISTLABOR	
81	Rate 25 Large Power General Plant 397	$ 333,287	5 2149%	$ 4,834,837	Line 34 * DISTLABOR	L29*$ALLOC_{CLASS}$
82	Rate 26 Petroleum Refinery	$ 3,743			Schedule P-3	
83	Rate 26 Petroleum Refinery Intangible	$ 474			Line 32 * DISTLABOR	
84	Rate 26 Petroleum Refinery General Plant 391	$ 128			Line 33 * DISTLABOR	
85	Rate 26 Petroleum Refinery General Plant 397	$ 140	0 0004%	$ 381	Line 34 * DISTLABOR	L29*$ALLOC_{CLASS}$
86	Rate 28 Area Lighting	$ 12,486,520			Schedule P-3	
87	Rate 28 Area Lighting Intangible	$ 157,429			Line 32 * DISTLABOR	
88	Rate 28 Area Lighting General Plant 391	$ 42,489			Line 33 * DISTLABOR	
89	Rate 28 Area Lighting General Plant 397	$ 46,494	1 1673%	$ 1,082,729	Line 34 * DISTLABOR	L29*$ALLOC_{CLASS}$
90	Rate 30 Electric Furnace	$ 1,032			Schedule P-3	
91	Rate 30 Electric Furnace Intangible	$ 131			Line 32 * DISTLABOR	
92	Rate 30 Electric Furnace General Plant 391	$ 35			Line 33 * DISTLABOR	
93	Rate 30 Electric Furnace General Plant 397	$ 39	0 0001%	$ 105	Line 34 * DISTLABOR	L29*$ALLOC_{CLASS}$
94	Rate 31 Military Reservation	$ 4,904			Schedule P-3	
95	Rate 31 Military Reservation Intangible	$ 622			Line 32 * DISTLABOR	
96	Rate 31 Military Reservation General Plant 391	$ 168			Line 33 * DISTLABOR	
97	Rate 31 Military Reservation General Plant 397	$ 184	0.0005%	$ 500	Line 34 * DISTLABOR	L29*$ALLOC_{CLASS}$
98	Rate 34 Cotton Gin	$ 989,680			Schedule P-3	
99	Rate 34 Cotton Gin Intangible	$ 20,102			Line 32 * DISTLABOR	
100	Rate 34 Cotton Gin General Plant 391	$ 5,425			Line 33 * DISTLABOR	
101	Rate 34 Cotton Gin General Plant 397	$ 5,937	0.0936%	$ 86,792	Line 34 * DISTLABOR	L29*$ALLOC_{CLASS}$
102	Rate 41 City and County	$ 32,742,029			Schedule P-3	
103	Rate 41 City and County Intangible	$ 680,163			Line 32 * DISTLABOR	
104	Rate 41 City and County General Plant 391	$ 183,570			Line 33 * DISTLABOR	
105	Rate 41 City and County General Plant 397	$ 200,874	3 0993%	$ 2,873,378	Line 34 * DISTLABOR	L29*$ALLOC_{CLASS}$
106	RWH Water Heating	$ 3,355,648			Schedule P-3	
107	RWH Water Heating Intangible	$ 158,759			Line 32 * DISTLABOR	
108	RWH Water Heating General Plant 391	$ 42,848			Line 33 * DISTLABOR	
109	RWH Water Heating General Plant 394	$ 46,887	0.3304%	$ 306,332	Line 34 * DISTLABOR	L29*$ALLOC_{CLASS}$
110	Distribution Gross Plant In Service	$ 1,090,792,394	100 0000%	$ 92,711,343		

EL PASO ELECTRIC COMPANY
2021 TEXAS RATE CASE FILING
TRANSMISSION BASELINE REVENUE REQUIREMENT

Line	Description		TCRF Baseline - Texas Jurisdiction	Reference
1	**Return on Transmission Invested Costs (TIC)**			
2	Transmission Gross Plant In Service	$	441,950,185	Schedule P-3; & L36
3	Transmission Accum Depr (Plant ACCT 350-359)	$	(193,221,217)	Schedule P-3
4	Transmission Invested Costs (TIC)	$	248,728,968	L2+L3
5	Accumulated Deferred Income Taxes	$	(48,589,682)	See Page 2
6	TIC net of ADIT	$	200,139,286	L4+L5
7	Weighted Average Cost of Capital (WACC)		7.985%	Schedule K-1
8	Return on TIC net of ADIT	$	15,981,602	L6*L7
9	**Operating Expenses**			
10	Transmission Depreciation Expense	$	7,497,814	Schedule P-2
11				
12	Property taxes		7,461,029	See Page 2
13	**Income and Other Taxes**			
14	Return	$	15,981,602	L8
15	Interest synchronization	$	(5,468,286)	L6* Interest Sync rate
16	Permanent and flow through differences	$	471,414	(Federal Perms - Excess Deferred Taxes) * L41
17	Taxable income	$	10,984,731	L14+L15+L16
18	Income tax factor		0.266966	Federal and State
19	Taxes before credits	$	2,932,547	
20	Excess deferred income taxes	$	(308,279)	Schedule P-2 * L41
21	Income tax expense	$	2,624,269	L19+L20
22	Revenue Requirements before revenue taxes and credits	$	33,564,714	L8+L15+L17+L21
23	Revenue tax gross up factor		1.050385214	WP A-3 Adj. 01
24	Revenue Requirements before credits	$	35,255,879	L22*L23
25	Texas revenue tax rate		0.043244309	WP A-3 Adj. 17
26	Revenue taxes	$	1,524,616	L24*L25
27	**Revenue Credits**			
28	Transmission of electricity for others	$	(19,509,898)	WP A-3 Adj. 01
29	Transmission-related Misc. Revenue Credit	$	-	
30	Revenue credits	$	(19,509,898)	L28+L29
31	**Revreqt**	$	**15,579,431**	L22+L26+L30
32	**Approved Transmission Charges (ATC)**			
33	Transmission of electricity by others (Account 565)		5,355,348	Schedule P-2
34	Total TCRF Baseline **(RR)**	$	20,934,779	L31+L33 (revreqt + ATC)
35	**Development of Transmission Plant Allocators**			
36	Transmission Gross Plant In Service	$	441,950,185	Schedule P-3
37	Gross Plant In Service	$	3,665,210,259	Schedule P-3
38	Transmission Gross Plant Allocator		12.06%	L36/L37
39	Transmission Net Plant In Service	$	248,728,968	Schedule P-3
40	Net Plant In Service	$	2,441,444,717	Schedule P-3
41	Transmission Net Plant Allocator		10.19%	L39/L40
42				

Line	Description		Balances	*Class* ALLOC	RR	Reference (Balances column)	Reference (RR Column)
43	**Development of Transmission Rate Class Allocators**						
44	Rate 01 Residential		244,078,320	55.2276%	$ 11,561,768	Schedule P-3	L34*ClassALLOC
45	Rate 02 Small General Service		20,997,823	4.7512%	$ 994,648	Schedule P-3	L34*ClassALLOC
46	Rate 07 Recreational Lighting		0	0.0000%	$ -	Schedule P-3	L34*ClassALLOC
47	Rate 08 Street Lighting		0	0.0000%	$ -	Schedule P-3	L34*ClassALLOC
48	Rate 09 Traffic Signals		57,399	0.0130%	$ 2,719	Schedule P-3	L34*ClassALLOC
49	Rate 11-TOU Municipal Pumping		7,044,641	1.5940%	$ 333,698	Schedule P-3	L34*ClassALLOC
50	Rate 15 Electric Refining		2,289,138	0.5180%	$ 108,434	Schedule P-3	L34*ClassALLOC
51	Rate 22 Irrigation Service		428,418	0.0969%	$ 20,294	Schedule P-3	L34*ClassALLOC
52	Rate 24 General Service		93,390,460	21.1314%	$ 4,423,821	Schedule P-3	L34*ClassALLOC
53	Rate 25 Large Power		30,370,066	6.8718%	$ 1,438,602	Schedule P-3	L34*ClassALLOC
54	Rate 26 Petroleum Refinery		12,241,284	2.7698%	$ 579,859	Schedule P-3	L34*ClassALLOC
55	Rate 28 Area Lighting		0	0.0000%	$ -	Schedule P-3	L34*ClassALLOC
56	Rate 30 Electric Furnace		1,516,920	0.3432%	$ 71,855	Schedule P-3	L34*ClassALLOC
57	Rate 31 Military Reservation		15,453,238	3.4966%	$ 732,006	Schedule P-3	L34*ClassALLOC
58	Rate 34 Cotton Gin		5,030	0.0011%	$ 238	Schedule P-3	L34*ClassALLOC
59	Rate 41 City and County		13,964,721	3.1598%	$ 661,496	Schedule P-3	L34*ClassALLOC
60	RWH Water Heating		112,726	0.0255%	$ 5,340	Schedule P-3	L34*ClassALLOC
61	Transmission Gross Plant In Service	$	441,950,185	100.0000%	$ 20,934,779		

EL PASO ELECTRIC COMPANY
Generation Cost Recovery Rider
Baseline Values
For the Test Year Ended December 31, 2020

			Non-Peaking D1PROD	Peaking D2PROD
1	Texas Retail Jurisdictional Production Allocation Factor (TRAF)		81.161%	81.125%

			kWh	kW
2	Rate Class Billing Determinants ($BD_{RC\text{-}CLASS}$)			
	TXRT01	Residential Service	2,478,851,326	
	TXRT02	Small General Service	272,309,109	
	TXRT07	Outdoor Recreational Lighting Service	3,676,526	
	TXRT08	Street Lighting	36,054,763	
	TXRT09	Traffic Signals	2,655,162	
	TXRT11TOU	Municipal Pumping Service - TOU	172,350,354	
	TXRT15	Electrolytic Refining Service	42,604,774	90,000
	TXRTWH	Water Heating Service	5,123,640	0
	TXRT22	Irrigation Service	3,840,029	0
	TXRT24	General Service	1,450,801,644	4,599,057
	TXRT25	Large Power Service	906,460,438	2,150,041
	TXRT26	Petroleum Refining Service	314,641,719	484,800
	TXRT28	Private Area Lighting Service	26,829,319	0
	TXRT30	Electric Furnace Rate	21,568,632	62,983
	TXRT31	Military Reservation Service	376,198,707	738,599
	TXRT34	Cotton Gin Service	1,596,380	5,904
	TXRT41	City and County Service	193,240,554	618,580
			6,308,803,076	8,749,964

3	Rate of Return (ROR_{RC})	7.985%

		Non-Peaking D1PROD	Peaking D2PROD
4	Rate Class Allocation Factors ($ALLOC_{RC\text{-}CLASS}$)		
		54.509784%	55.227531%
		4 720715%	4.751144%
		0.031061%	0.000000%
		0 304683%	0 000000%
		0 017541%	0.013009%
		1.626529%	1.593972%
		0.520633%	0.517953%
		0.043298%	0.025526%
		0.095424%	0.096966%
		21.124188%	21.131447%
		6.941673%	6.871827%
		2.827593%	2.769863%
		0.226723%	0.000000%
		0.341522%	0.343250%
		3.508930%	3.496609%
		0.013490%	0.001128%
		3.146212%	3.159777%
		100.000000%	100.000000%

DOCKET NO. ______

APPLICATION OF EL PASO ELECTRIC COMPANY TO CHANGE RATES	§ § §	PUBLIC UTILITY COMMISSION OF TEXAS

DIRECT TESTIMONY

OF

MANUEL CARRASCO

FOR

EL PASO ELECTRIC COMPANY

JUNE 2021

EXECUTIVE SUMMARY

Mr. Manuel Carrasco is Manager of Rate Research in El Paso Electric Company's ("EPE" or "Company") Regulatory Affairs Department. In his testimony, Mr. Carrasco describes the process by which energy sales, class demands, and revenues were adjusted to reflect normal, recurring operating conditions in determining test period, and non-fuel base revenues for the Texas jurisdiction. Mr. Carrasco also describes and supports the rates and rate structures that EPE proposes in this application, based on the cost of service studies developed by EPE, and the analyses of the impact of the proposed rates on EPE customers. Finally, he supports the proposed revisions to rate schedule provisions.

TABLE OF CONTENTS

EXHIBITS

I. Introduction and Qualifications

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

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

Q. HOW ARE YOU EMPLOYED?

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

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL AND PROFESSIONAL QUALIFICATIONS.

A. I hold both a Bachelor in Accounting and a Master in Economics from New Mexico State University ("NMSU"). I graduated from NMSU's Accounting program, with honors, in 1995 and from NMSU's Regulatory Economics program in 1999. NMSU's Regulatory Economics program consists of specific courses related to public utilities such as revenue requirements, cost allocation, and pricing in the utility industry. This concentrated graduate program is offered by only a few universities nationwide.

My professional career began in 1993 as a rate analyst with the Utilities Department of the City of Las Cruces, New Mexico, where my responsibilities included performing cost of service and rate design studies; preparing fiscal budget and financial forecasts; and developing forecasts of customers, consumption, and revenues. During my tenure with the City of Las Cruces, I received increasing levels of responsibility culminating with a promotion to Manager of the Rate & Economic Analysis section. My experience also includes working as an Accountant/Analyst at Sierra Pacific Power Company and as a Senior Pricing Analyst at Colorado Springs Utilities.

I began working for EPE in 2009 as a Rate Analyst Specialist. In 2011, I was promoted to Senior Rate Analyst; promoted to Supervisor in 2015; and in 2018, I was promoted to my current position.

In addition to my professional experience and education, I have attended professional development seminars sponsored by National Economic Research Associates (also known as NERA Economic Consulting, Inc.), Electric Utility Consultants Inc., The Brattle Group, NMSU's Center for Public Utilities, American Gas Association, Edison Electric Institute, Association of Edison Illuminating Companies, and American Water Works Association.

Q. PLEASE DESCRIBE YOUR CURRENT RESPONSIBILITIES WITH EPE.

A. As Manager of Rate Research, my responsibility is to provide oversight of the preparation of economic, statistical, cost and rate design studies; development of models and methodologies for cost of service, profitability and pricing studies; and performing annualization and revenue forecasts.

Q. HAVE YOU PREVIOUSLY PRESENTED TESTIMONY BEFORE UTILITY REGULATORY BODIES?

A. Yes, I have previously filed testimony with the Public Utility Commission of Texas ("PUCT" or "Commission") and testified before the New Mexico Public Regulation Commission.

II. Purpose of Testimony

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. My testimony presents EPE's adjustments of total company (i.e., both Texas and New Mexico jurisdictions) billing determinants and the computation of adjusted Test Year base revenues at present rates. I also explain the process EPE undertook for estimating the proposed final class revenue allocation, as supported by the Class Cost of Service ("CCOS") study, including the process of "capping" the base revenue impact on certain rate classes.[1] My testimony describes EPE's rate design based on this base revenue allocation for all rate classes and an evaluation of the impact of EPE's rate proposals on customers. I discuss revisions to miscellaneous service charges. Finally, I discuss EPE's proposals to revise the terms of service for rate schedules.

Q. ARE YOU SPONSORING ANY EXHIBITS IN YOUR TESTIMONY?

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[1] EPE witness James Schichtl also discusses the Company's criteria used for the base revenue impact moderation or "capping" process.

A. Yes. I am sponsoring the following exhibits, which are attached to this testimony:

- Exhibit MC-1: Sponsored Schedules
- Exhibit MC-2: DCRF and TCRF Revenue
- Exhibit MC-3: Energy Efficiency Annualization Adjustment
- Exhibit MC-4: Base Revenue Increase Allocation by Rate Class
- Exhibit MC-5: Historical Allocator Comparison
- Exhibit MC-6: Comparison of Current to Proposed Rates
- Exhibit MC-7: Residential Monthly Bill Impacts
- Exhibit MC-8: Excess ADIT Refund by Rate Class
- Exhibit MC-9: COVID-19 Amortization by Rate Class

Q. WHAT SCHEDULES DO YOU SPONSOR OR CO-SPONSOR?

A. Exhibit MC-1 lists the required PUCT's Electric Utility Rate-Filing Package for Generating Utilities ("RFP") schedules I sponsor or co-sponsor.

Q. WERE THE RFP SCHEDULES AND EXHIBITS YOU ARE SPONSORING PREPARED BY YOU OR UNDER YOUR DIRECT SUPERVISION?

A. Yes, they were.

III. Adjustments to Base-Rate Revenues

A. Overview

Q. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?

A. In this section of my testimony, I discuss EPE's adjustments to base-rate revenues (i.e., Base and Non-firm Base-Rate Revenues). The adjustments applied to the Texas jurisdiction are shown in Schedule A-1 as the difference between Total Per Books and At Existing Rates, As Adjusted amounts, in the Adjustments column (c), lines 1 and 2. Adjustments to EPE's fuel revenues are discussed in the Direct Testimony of EPE witness Adrian Hernandez.

Q. ARE ADJUSTMENTS TO HISTORICAL TEST YEAR DATA AUTHORIZED BY THE PUCT?

A. Yes. 16 Texas Administrative Code ("TAC") § 25.234(b) states that "[r]ates will be determined using revenues, billing, and usage data for a historical test year adjusted for known and measurable changes, and costs of service as defined in TAC § 25.231 of this title (relating to Cost of Service)."

Q. WHAT IS THE HISTORICAL TEST YEAR THAT THE PROPOSED ADJUSTMENTS ARE MADE TO?

A. EPE's Historical Test Year for this case is the twelve-month period ended December 31, 2020.

Q. WHAT TYPES OF ADJUSTMENTS HAVE BEEN MADE TO EPE'S HISTORICAL TEST YEAR DATA TO DETERMINE ADJUSTED TEST YEAR REVENUES?

A. To ensure that the Test Year is indicative of what is likely to occur under normal, recurring operating conditions, EPE has annualized and normalized historical Test Year billing and usage data to determine adjusted Test Year base revenues at present rates. The adjustments, tabulated in RFP Schedule O-4.1, are explained below and primarily enumerate the impact of (1) annualizing year-end customer growth or decline; (2) normal weather; (3) the impact of Commission-approved energy efficiency programs; and (4) other known and measurable changes. The adjusted Test Year billing and usage data are inputs into the jurisdictional and class cost of service allocations and form the basis for the billing determinants on which rates are designed. An explanation of each of these adjustments is provided in this section.

Additionally, I explain base-rate revenue adjustments because of changes in base rates during the Test Year. I co-sponsor workpaper Adj. No. 1 to Schedule A-3 which contains the reference to the base revenue adjustments I describe in this testimony.

Q. DO THE BASE REVENUES IN SCHEDULE A-1 REFLECT THE EFFECT OF THE TAX CUTS AND JOBS ACT OF 2017 ("TCJA")?

A. Yes. The Total Per Book and the At Existing Rates, As Adjusted base revenues amounts shown in Schedule A-1 reflect the effect of the TCJA. On April 1, 2018, an interim rate rider was implemented that provided for the refunding of income tax expense through credits to Texas customers base charges on bills issued beginning on that date. On December 10, 2018 in its order in Docket No. 48124,[2] the Commission confirmed EPE's compliance with the Settlement Agreement ("Settlement") and the Commission's Final Order ("Final Order") in EPE's last base rate case, Docket No. 46831.[3] The interim rate rider effectively reduced base revenue by 4.5515%, commensurate to the reduction in federal income tax expense corresponding to the Company's Texas jurisdiction. This reduction in base revenue is to remain in place until the effective date of rates in EPE's next base rate case, which is the current case. The 4.5515% was applied to the base-rate revenue resulting from the adjusted billing and usage discussed in this section of this testimony, which reduced the adjusted base revenue by $23,847,054.

Q. DO THE BASE REVENUES IN SCHEDULE A-1 REFLECT THE EFFECT OF THE TRANSMISSION COST RECOVERY FACTORS AND DISTRIBUTION COST RECOVER FACTORS THAT EPE IMPLEMENTED SINCE ITS LAST BASE RATE CASE FILING?

A. Yes. The Total Per Book base-rate revenue amount shown in Schedule A-1 reflects the transmission cost recovery factors ("TCRF") and the distribution cost recovery factors ("DCRF") that were in effect during 2020. The At Existing Rates, As Adjusted base-rate revenue amount shown in Schedule A-1 also reflects the transmission cost recovery factors that were in effect during 2020 and, as explained later in this testimony, the recently approved distribution cost recovery factors. Both TCRF and DCRF are applied to the adjusted billing and usage discussed in this section of this testimony in the determination of adjusted base revenue and total $7.6 million and $20.2 million, respectively, as shown in Exhibit MC-2.

Q. HOW ARE BASE REVENUES RELATED TO EPE'S COMMUNITY SOLAR SERVICE HANDLED IN THIS FILING?

A. For this filing, the base revenue related to the community solar service monthly capacity

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[2] *Application of El Paso Electric Company to Implement a Refund Tariff for Federal Income Tax Rate Decrease in Compliance with Docket No. 46831*, Docket No. 48124, Order (Dec. 10, 2018).

[3] *Application of El Paso Electric Company to Change Rates*, Docket No. 46831, Order (Dec. 18, 2017).

charge are excluded from the Texas jurisdiction revenues and not shown in Schedule A-1. This is consistent with the handling of the costs related to this service.

Q. WERE BILLING AND USAGE ADJUSTMENTS MADE TO ALL JURISDICTIONS SERVED BY EPE?

A. Yes. Adjusting billing and usage of all jurisdictions served by EPE ensures that the Company's total cost of service is properly allocated to the jurisdictions.

1. Description of Adjustments to Base-Rate Revenues

Q. WHAT ARE THE TEST YEAR BASE-RATE REVENUES RESULTING FROM THESE ADJUSTMENTS?

A. The table below summarizes the base-rate revenues at present rates resulting from these adjustments.

Table MC-1

Adjustment to	Texas
Per Book Base-Rate Revenue	$532,530,138
Base-Rate Revenue Adjustments	$4,357,844
As Adjusted Base-Rate Revenue	$536,887,982

a. Year-End Customer Annualization

Q. WHAT IS THE TEST YEAR-END CUSTOMER ANNUALIZATION?

A. Test Year-end customer annualization is the process by which historical Test Year data has been adjusted to account for known and measurable changes in the number of customers or known changes in energy and demand usage.

Q. WHAT IS THE PURPOSE OF TEST YEAR-END CUSTOMER ANNUALIZATION?

A. The purpose of annualizing the Test Year customers, revenues, sales, and demand is to adjust these items to a level representative of ongoing conditions had the number of customers at year-end been served for the entire year.

Q. WHICH RATE CLASSES WERE ANNUALIZED FOR TEST YEAR-END CUSTOMERS?

A. The following Texas rate classes exhibited a significant change in total number of customers or energy and demand usage during the Test Year, making them subject to an annualization adjustment:

- Residential Service,
- Small General Service,
- General Service,
- Interruptible Service, and
- City and County Service.

Some rate classes exhibited less significant changes but were also subject to an annualization adjustment:

- Street Lighting Service,
- Water Heating Service,
- Irrigation Service,
- Large Power Service, and
- Area Lighting Service.

Schedule O-4.1, pages 3 and 4, provides the energy, billing demands, and revenue impacts by rate class due to the Test Year-end customer annualization adjustment. Schedule O-3.3 provides the change in annual customers by rate class. A similar annualization adjustment was made to New Mexico rate classes because those billing and usage data are used in conjunction with Texas in calculating the jurisdictional allocation factors.

Q. WHAT IS THE BASE-RATE REVENUE ADJUSTMENT DUE TO THE YEAR-END CUSTOMER ANNUALIZATION ADJUSTMENT?

A. The table below summarizes the adjustment to base-rate revenues at present rates and billing determinants resulting from the year-end customer annualization adjustment.

Table MC-2

Adjustment To:	Texas
Base-Rate Revenue	$4,943,556
Billed kilowatt-hours	35,882,010
Billed kilowatts	(9,021)
Annual Customers	40,402

b. Weather Normalization

Q. WHY IS TEST YEAR DATA WEATHER NORMALIZED?

A. Test Year data is normalized to reflect normal weather conditions.

Q. WHICH RATES CLASSES WERE WEATHER NORMALIZED?

A. The energy sales of the following Texas rate classes were weather normalized:

- Residential Service,
- Small General Service,
- Irrigation Service,
- General Service,
- Military Service, and
- City and County Service.

Energy sales of weather-sensitive rate classes in the New Mexico jurisdiction were also weather normalized, because those sales are used in conjunction with Texas energy sales in calculating the energy jurisdictional allocation factors.

Q. PLEASE DESCRIBE THE WEATHER NORMALIZATION ADJUSTMENT PROCESS.

A. Weather normalization of energy use is performed by EPE's Economic Research group, which is led by EPE witness George Novela. Please refer to EPE witness Novela's direct testimony for specific discussion of the weather normalization methodology.

The base-rate revenue adjustment is calculated by the Rate Research group, based on the weather normalization data provided by Economic Research. The calculation simply applies the appropriate energy charge to each rate class' monthly energy sales adjustment.

Q. WHAT IS THE BASE-RATE REVENUE ADJUSTMENT DUE TO WEATHER NORMALIZATION ADJUSTMENT?

A. During 2020, energy sales were higher than normal by over 104.7 million kilowatt-hours ("kWh") due to the weather. Thus, to make the Test Year revenues reflect normal weather, an adjustment to decrease base-rate revenue was made. The following table summarizes the adjustment to base-rate revenues at present rates and billing determinants resulting from the weather normalization adjustment.

Table MC-3

Adjustment To:	Texas
Base-Rate Revenue	($9,435,724)
Billed kWh	(104,734,699)

Schedule O-4.1 provides the energy and revenue impacts by rate class due to weather normalization.

Q. WHY IS NO ADJUSTMENT MADE TO BILLED KILOWATTS ("KW") FOR WEATHER?

A. No adjustments were made to billed kW because individual customer's non-coincident kW load of heating and cooling equipment is not weather sensitive. Rather, the equipment's cycling and duration of those cycles is what is assumed to be weather-sensitive, thus only affecting energy usage. Billed kW is based on non-coincident kW load, a minimum kW, or a ratcheted kW amount.

c. Energy Efficiency Program Annualization

Q. WHAT ADJUSTMENT WAS MADE TO ANNUALIZE FOR THE IMPACT OF TEXAS ENERGY EFFICIENCY PROGRAMS?

A. The Energy Efficiency Rule ("EE Rule"), 16 TAC §§ 25.181 and 25.183, mandates that investor-owned electric utilities administer a portfolio of energy efficiency programs. To comply with the EE Rule, EPE submitted its 2021 Energy Efficiency Plan and Report[4] ("EEPR") detailing its achievements for 2019 and 2020 and EPE's plans for achieving its 2021 projected energy efficiency savings goals. The EEPR indicates that EPE achieved unverified annual kWh savings of 30,669,898 in 2020.

To recognize the impact of the implementation of these energy efficiency programs, energy billing determinants for the Texas jurisdiction were annualized by reducing kWh sales by 21,657,352 kWh to reflect kWh savings for the full twelve-month period of the Test Year. Actual savings from the installed measures that are included in recorded billed energy during the Per Book Period are estimated at 9,012,537 kWh. Exhibit MC-3

[4] *See* Schedule N-6.

provides the detailed calculations of the kWh adjustment for the impact of the Texas energy efficiency programs.

Energy savings, at full customer participation at the end of the Test Year, is estimated to be 2.7 million kWh per month in the summer months (June through September) and 2.5 million kWh per month in the non-summer months.

The table below summarizes the non-fuel, base revenue adjustments at present rates resulting from energy savings brought about by the approved energy efficiency programs.

Table MC-4

Adjustment To:	Texas
Base Revenue	$(1,101,806)
Billed kWh	(21,657,352)

A similar adjustment to reduce New Mexico kWh sales for the energy efficiency programs in that jurisdiction was made because those sales are used in conjunction with Texas energy sales in calculating the energy jurisdictional allocation factors. Schedule O-4.1 provides the energy and revenue impacts by rate class.

Q. WHAT IS THE SOURCE OF INFORMATION FOR THE ENERGY EFFICIENCY ANNUALIZATION ADJUSTMENT?

A. I obtained the information for the energy efficiency annualization adjustment from EPE's Energy Efficiency Department. The Energy Efficiency Department compiles energy savings based on program expenditures throughout the year, which are then verified by the Commission approved Measurement and Verification Evaluator. As of the writing of this testimony, the annual energy savings from the preliminary analysis of the installed measures for the 2020 program year had not yet been measured and verified by the evaluator.

d. Changes in Base Rates

Q. WHAT BASE RATE CHANGES OCCURRED DURING THE TEST YEAR IN EPE'S TEXAS RETAIL JURISDICTION?

A. Revision 1 of Schedule No. TCRF – Transmission Cost Recovery Factor[5] took effect in the Texas retail jurisdiction on March 1, 2020.

Q. HAVE YOU ANNUALIZED THE CHANGES IN BASE RATES THAT OCCURRED DURING THE TEST YEAR?

A. No. The revision to Schedule No. TCRF was to implement a relate-back surcharge over a 12-month period, but the amounts the surcharge intended to recover were recognized as base revenue in 2019.

e. Other Known and Measurable Changes

Q. WHAT IS THE PRO FORMA REVENUE ADJUSTMENT DUE TO OTHER KNOWN AND MEASURABLE CHANGES IN EPE'S FILING?

A. Adjustments due to other items are summarized in the following table.

Table MC-5

Adjustment To:	Texas
Base Revenue	($1,210,882)
Billed kWh	1,688,856
Billed kW	0

These adjustments include other known and measurable adjustments. One of them is to remove the effect of normalizing the firm service of a major interruptible customer that failed to curtail consumption during an interruption, which resulted in the interruptible portion of the customer's usage being billed at firm rates under the terms of the customer's service. EPE applied the non-compliance provision of Schedule No. 38 to assess this customer with an additional billed amount of $1,212,341. To normalize the Test Year revenue, this amount is removed from the base revenues.

The other is to show the less significant out-of-period adjustments made to per book data to account for energy recorded during the Test Year that is associated with months outside of the Test Year. Due to the seasonal rate structures of some rate classes, out-of-period adjustments are also made to months within the Test Year. Out-of-period

[5] The original Schedule No. TCRF – Transmission Cost Recovery Factor took effect on July 30, 2019.

adjustments may be needed due to missed meter reads or incorrect input of the meter reading data for a prior month that were corrected in subsequent months' bills. The revenue adjustment for the out-of-period adjustments amounted to an increase of only $1,458.

Q. ARE THERE ANY OTHER ADJUSTMENTS MADE TO BASE REVENUES?

A. Yes. Other adjustments to base revenues include the removal of unbilled base revenue, reflection of the recent Commission-approved update of Schedule No. DCRF, and the expiration of Schedule No. RCES.

Revision 1 of Schedule No. DCRF – Distribution Cost Recovery Factor[6] took effect in the Texas retail jurisdiction on March 1, 2021. Although the effective date is post-Test Year, EPE has adjusted base revenues upward by $12,431,284 to reflect this recent change. Additionally, Schedule No. RCES – Rate Case Expense Surcharge expired in January 2021. Revenue from this surcharge is considered base revenue, thus an adjustment was made to remove from base revenues $1,586,584 of RCES revenue billed during the Test Year.

Unbilled base revenues, which are intended to recognize revenue for estimated consumption yet to be billed in a month, are removed from base revenues. In the current Test Year, EPE recorded $318,000 in net unbilled base revenue for Texas. This adjustment increased the amount of recorded base revenue.

2. Base Revenue Adjustment Recap

Q. WHAT ARE THE HISTORICAL TEST YEAR PERIOD BASE REVENUES RESULTING FROM THESE ADJUSTMENTS?

A. The table below summarizes the Texas jurisdiction base-rate revenues at present rates resulting from these adjustments.

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[6] The original Schedule No. Schedule No. DCRF – Distribution Cost Recovery Factor took effect on October 1, 2019.

Table MC- 6

	Texas
Per Book Base Revenue[7]	$532,530,138
Base Revenue Adjustments:	
Year-End Customer Annualization[8]	$4,943,556
Weather Normalization[9]	(9,435,724)
Energy Efficiency Program Impact[10]	(1,101,806)
Other Known and Measurable Changes[11]	(1,210,882)
DCRF Update[12]	12,431,284
Rate Case Expense Surcharge[10]	(1,586,584)
Unbilled Base Revenues	318,000
Total Base Revenue Adjustments	$4,357,844
Adjusted Base Revenue (at present rates)	$536,887,982

IV. Adjustments to Other Operating Revenues

Q. WHAT ADJUSTMENTS WERE MADE TO OTHER OPERATING REVENUES?

A. An adjustment in the amount of $844,298 was made to increase Other Operating Revenues is the result of the normalization of late payment penalty fees. Consistent with the COVID-19 expense adjustments that EPE witness Cynthia S. Prieto discusses in her Direct Testimony, it is necessary to adjust late payment penalty fees to pre-pandemic levels. To arrive at the pre-pandemic amount, EPE used a three-year average of the amounts recorded as Forfeited Discounts (FERC Account 450) for years 2017 through 2019, which resulted in an increase of $844,298 in Other Operating Revenues. See Table MC-7 below for details on this calculation.

Table MC-7

(450) Forfeited Discounts [13]	Texas
2017	$1,504,634
2018	1,208,316
2019	1,115,585
3-year Average	$1,276,178
2020	431,880
Difference (Adjustment)	$844,298

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7 Per Book Base Revenue includes amounts billed through base rates and Commission-approved riders (e.g., TCRF, DCRF, RCES, etc.). It also includes $318,000 for unbilled revenue recognized as a reduction in base revenue.

8 RFP Schedule Q-4.1, pages 3 and 4.

9 RFP Schedule Q-4.1, page 5.

10 RFP Schedule Q-4.1, page 7.

11 RFP Schedule Q-4.1, pages 8 and 9 include the adjustment for the non-compliant interruptible customer; page 10 includes the out-of-period adjustment.

12 RFP Schedule Q-4.1, page 2.

13 Source: FERC Form 1, page 300, line number 16.

V. Proposed Base Revenue Allocation By Rate Class

Q. WHAT IS EPE'S TOTAL SYSTEM AVERAGE BASE REVENUE INCREASE PROPOSED IN THIS CASE?

A. As detailed in the Direct Testimony of EPE witness Hernandez, and as shown in Schedule A-1, EPE's revenue deficiency is $41.097 million. This equates to a proposed total base-rate revenue increase, including non-firm revenues, of $41.818 million or a system average increase of 7.79%[14] and a proposed $721 thousand reduction in miscellaneous charges. Approximately $2.196 million of the base-rate revenue increase will be provided by the proposed COVID-19 surcharge, which I discuss later in my testimony.

Q. WHAT IS EPE'S PROPOSAL TO LIMIT THE RATE CLASS IMPACT OF ITS PROPOSED BASE REVENUE INCREASE?

A. As addressed in the Direct Testimony of EPE witness Schichtl, because of the effect of the COVID-19 pandemic, EPE is proposing in this case an initial limit or "cap" of the indicated base revenue increase for certain rate classes to a maximum of one and a half (1.5) times the non-fuel base revenue increase for all retail rates, or 11.07%[15] and a floor for certain other rate classes that EPE's CCOS indicated base-rate revenue decreases. No cap or floor was applied to the remaining rate classes.

Q. WHICH RATE CLASSES WOULD BE SUBJECT TO EPE'S PROPOSED CAP OR FLOOR TO THE BASE REVENUE INCREASE OR DECREASE?

A. Under EPE's proposed cap for the base revenue increase, the Residential Service and the Water Heating rate classes will be subject to the capped non-fuel increase of 11.07%. Under EPE's proposed floor, the Small General Service, the General Service, and the City & County Service rate classes will be subject to the floor applied to their decrease.

Q. WHAT PROCESS WAS USED BY EPE TO IMPOSE A CAP OR FLOOR TO THE

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[14] EPE is proposing a non-firm base rate revenue increase at the system average or $325 thousand. The base-rate revenue increase from the rate classes, net of the non-firm base rate revenue increase, is $41.493 million.

[15] ($41,818 million total base rate increase – $2.196 million for COVID-19 surcharge – $0.325 million for non-firm base rate revenue increase) / $532.714 in base rate revenue at present rates = 7.38% × 1.5 = 11.07%.

PROPOSED BASE REVENUE INCREASE TO RATE CLASSES?

A. Exhibit MC-4 shows the derivation of the proposed class base revenue allocation, including the caps or floors discussed above. The application of the proposed cap (or "capping" process) starts with each rate class' full cost allocation as calculated by EPE witness Hernandez and shown in Schedule P-6 as supported by the CCOS study. Then, EPE applied the proposed cap of 11.07% to the resulting base revenue increase determined for each capped rate class and a floor of 50% of the indicated decrease for each floored rate class. To the extent that the allocated base revenue increase at full cost for any given rate class results in a percentage increase exceeding the proposed cap and floor, EPE redistributed that excess revenue to all rate classes proportional to their combined total revenue.

Q. WHAT DO YOU MEAN BY "PROPORTIONALLY TO THEIR COMBINED TOTAL REVENUE"?

A. "Proportionally to their combined total revenue" means that any rate class's base-rate revenue requirement in excess of the cap and floor was redistributed to the all rate classes using the ratio resulting from dividing each class's specific revenue requirement (after the initial cap or floor, as applicable) by the total revenue requirement (after the initial cap or floor, as applicable). For example, if after applying the cap and floor, the base-rate revenue requirement for a class, such as General Service, was 10% of the total initially capped and floored revenue requirement, the class would receive 10% of the revenue requirement in excess of the cap and floor.

Q. WHY IS EPE PROPOSING TO HAVE ONLY AN UPPER AND LOWER LIMIT FOR ITS PROPOSED BASE REVENUE INCREASE OR DECREASE FOR CERTAIN CLASSES?

A. EPE's rationale to apply caps and floors is based on the observation of significant changes in certain class allocation factors, which is suspected to be most likely due to the COVID-19 pandemic shutdown during 2020, as discussed by EPE witness Novela. For example, Exhibit MC-5 shows the Test Year energy and demand allocation factors of the residential rate class experienced an increase of 500 to 1,100 basis points from historical allocation factors. Conversely, the energy and demand allocation factors of the General

Service rate class experienced decreases of 200 to 600 basis points. This means cost shifting has occurred from nonresidential rate classes to the residential rate class.

From a rate design perspective, and due to the resulting revenue allocation at full cost of service, EPE's proposal to cap the upper limit of the base revenue increase and a lower limit to base revenue decreases attends to the generally accepted principle of gradualism that will mitigate potential rate shocks for customers within the residential rate class. Also, by proposing a cap and floor at a reasonable level in this case, EPE is still making some progress to align cost causation with cost recovery by moving rate classes closer towards full cost revenue allocation and rate design.

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

A. Table MC-8 below summarizes both the base revenue allocation by class at full cost of service, and after the proposed "capping and flooring" process discussed above. The Capped/Floored cost of service amounts of each class presented in the table are the targeted revenue for the rate design process.

Table MC- 8

Rate	Rate Class	Base Rate Revenue @ Present Rates	Full Cost of Service *	Full Cost % Revenue Increase	Capped/Floor Cost of Service	Cap/Floor Revenue Increase %	Capped/Floored Revenue Increase $
01	Residential Servcie	$ 273,638,830	$ 324,724,406	18.67%	$ 310,823,371	13.59%	$ 37,184,541
02	Small General Service	33,319,685	29,985,897	-10.01%	32,372,084	-2.84%	(947,601)
07	Outdoor Recreational Lighting	462,980	613,998	32.62%	627,951	35.63%	164,971
08	Government Street Lighting	4,046,620	3,063,775	-24.29%	3,133,398	-22.57%	(913,222)
09	Traffic Signals	95,204	98,208	3 16%	100,440	5.50%	5,236
11TOU	Municipal Pumping TOU	10,102,350	10,158,249	0.55%	10,389,089	2.84%	286,739
15	Electrolytic Refining Service	1,830,063	2,228,715	21.78%	2,279,361	24.55%	449,298
WH	Water Heating Service	474,582	804,466	69.51%	539,073	13 59%	64,491
22	Irrigation Service	423,413	556,623	31.46%	569,272	34.45%	145,859
24	General Service	125,005,740	113,791,588	-8.97%	122,111,933	-2.31%	(2,893,807)
25	Large Power Service	35,955,664	37,134,334	3.28%	37,978,192	5.63%	2,022,528
26	Petroleum Refinery Service	10,964,770	12,891,636	17.57%	13,184,591	20.25%	2,219,821
28	Area Lighting Service	2,932,614	2,636,450	-10 10%	2,696,362	-8.06%	(236,252)
30	Electric Furnace Rate	1,191,760	1,500,889	25.94%	1,534,996	28.80%	343,236
31	Military Reservation Service	13,009,892	14,718,900	13.14%	15,053,379	15.71%	2,043,487
34	Cotton Gin Service	132,972	177,564	33.53%	181,599	36.57%	48,627
41	City and County Service	19,126,500	16,924,524	-11.51%	18,435,132	-3.61%	(691,368)
Total		$ 532,713,639	$ 572,010,221	7.38%	$ 572,010,221	7.38%	$ 39,296,582

* Net of $325,136 increase to Non-Firm Revenue and $2,196,060 amount COVID19 expenses to be recovered through a rider

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Rate	Rate Class	Base Rate Revenue @ Present Rates	Full Cost of Service *	Full Cost % Revenue Increase	Capped/Floor Cost of Service	Cap/Floor Revenue Increase %	Capped/Floored Revenue Increase $
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* Net of $325,136 increase to Non-Firm Revenue and $2,196,060 amount COVID19 expenses to be recovered through a rider.

VI. Proposed Rate Design

A. Overview

Q. WHAT ARE THE PRIMARY GOALS EPE SEEKS TO ACHIEVE WITH THE PROPOSED RATE DESIGN PRESENTED IN THIS CASE?

A. EPE seeks to achieve a variety of goals through its proposed rate design. These goals for rate design include the following, in no particular order of significance:

- Minimizing subsidies within rate classes and sending accurate price signals by ensuring classification component costs (i.e., demand, energy, and customer costs) are recovered consistently with how these costs are incurred;
- Ensuring rate structures are supported by cost causation principles and, to the extent possible, encourage energy conservation and potentially reduce contributions to EPE's system peak demand;
- Providing stable rates for customers; and
- Promoting stability of revenues to allow EPE the opportunity to recover its costs of providing safe and reliable service to Texas customers.

Q. HOW DOES THE COMPANY PROPOSE TO MINIMIZE SUBSIDIES WITHIN EACH RATE CLASS?

A. Subsidies within a rate class occur when the components of the rates charged do not adequately reflect the underlying costs to serve. EPE proposes to minimize intra-class subsidies, to the extent possible, by ensuring that the proposed rates adequately recover each classification component cost in a manner that appropriately reflects their cost causation. Recovering costs based on factors that reasonably reflect their cost causation results in price efficiency and reduces the potential that some customers within a rate class will subsidize other customers within the same rate class.

Q. ARE THERE CHANGES PROPOSED BY EPE DESIGNED TO ADDRESS THE INTRA-CLASS SUBSIDIZATION THAT ARE COMMON ACROSS RATE CLASSES?

A. Yes. The Company is proposing to move the monthly customer charges closer to the full cost of service and in some cases to fully recover all the customer-related costs identified in the CCOS from the customer charges. Increasing the customer charge to full cost of service, where possible, reduces intra-class subsidies and improves the accuracy of the price signal provided by the volumetric energy charge.

Similarly, the Company proposes to set demand charges to reflect the costs of providing the associated electric service more accurately. For all rate classes with demand charges, EPE is proposing to set demand charges to the full cost of service and in some cases to fully recover all the demand-related costs identified in the CCOS from the demand charges. Therefore, aligning the monthly customer and demand charges with their underlying costs, reduces intra-class subsidies and improves the accuracy of the price signals.

Q. IS EPE PROPOSING RATE STRUCTURES THAT ENCOURAGE ENERGY CONSERVATION AND POTENTIALLY REDUCE CUSTOMERS' CONTRIBUTION TO EPE'S SYSTEM PEAK?

A. Yes. Accurate price signals communicate customers cost differences between seasons and time periods, which allows customers to make economic decisions, promote energy conservation, and encourage customers to shift usage from peak periods to off-peak periods. EPE's proposed changes to demand and energy charges are intended to produce more accurate price signals that communicate those price differentials to customers, particularly during summer months. EPE is proposing to set demand charges to collect demand-related cost in both the summer and the non-summer months (previously referred to as "Winter"), by assigning demand-related costs to seasons as a function of the system loads. For those rate classes with a time variant pricing structure, energy charges are developed with on-peak period energy price differentials that reflect the incremental generation costs, which has the intended effect of reducing contributions to EPE's system peak. Finally, EPE proposes to remove those declining-block energy rate structures that do not have any cost justification, which otherwise do not support energy efficiency and conservation.

Q. DO EPE'S PROPOSED RATES ENHANCE RATE STABILITY FOR CUSTOMERS?

A. Yes. Because EPE's cost of service and cost responsibility by rate class generally do not vary widely from year-to-year, cost-based rates should be similarly stable, avoiding significant rate volatility for customers. Rates that more closely follow their underlying cost, which would thus provide customers with more accurate price signals, would normally allow customers to reasonably anticipate what their electric bills will be and make economic decisions regarding their electric consumption.

Q. DO THE PROPOSED RATES PROMOTE STABILITY OF REVENUES FOR EPE?

A. Yes. The proposed rates link revenues more closely to costs, thereby ensuring that the costs are reasonably matched with revenues. That is, by sending customers more accurate price signals, EPE anticipates that future cost increases (or decreases) will better track future revenue increases (or decreases). In addition, EPE's proposed rates attempt to provide a better recovery of fixed costs (i.e., costs that do not vary with the amount of kWh) through more accurate customer and demand charges.

Q. HOW HAS EPE EMPLOYED THE RESULTS OF ITS CLASS COST-OF-SERVICE STUDY IN ITS PROPOSED RATES?

A. Based on a review of EPE's cost of service, the associated rate class revenue deficiencies by customer class identified in that review and the proposed "capping and flooring" previously discussed in this testimony, EPE has proposed a number of changes to its rates that are necessary to better reflect the costs of providing service, particularly in determining the individual rate components: customer, demand, and energy charges. EPE's proposed changes to these charges and contained in its proposed tariffs were developed to more accurately reflect the customer, demand, and energy classification component unit costs calculated for each rate class, as provided in the cost of service schedule P-6.

Q. WHAT RATES OR RATE CHANGES IS EPE PROPOSING IN THIS CASE TO IMPROVE ACCURATE PRICE SIGNALS?

A. The Company is proposing a variety of rate structure modifications that will provide more accurate price signals to customers. These proposed modifications include:

- Moving customer charges to full cost of service, collecting all the customer-related costs in the customer charge.
- Aligning the recovery of demand-related costs with demand charges while limiting seasonal demand charges to collect no more than 100% of the demand-related costs.
- Shortening the summer season from six months (May through October) to four months (June through September) for all applicable retail standard tariffs.[16]
- Modifying the Summer on-peak period and off-peak period price differentials for TOD rates to reflect EPE's incremental capacity cost and provide more effective incentives to consumers to shift load or reduce peak consumption during the entire summer season.

Q. DESCRIBE EPE'S GENERAL PROCESS TO DESIGN ITS PROPOSED BASE RATES IN THIS CASE?

A. Although rates can be theoretically developed following any sequence with respect to the different cost elements, EPE chose to start the rate design process with the determination of the customer charge for each rate class. As a general principle, EPE targeted a customer charge that would allow for the recovery of 100% of the customer-related costs for each rate class.

Next, if applicable, EPE proceeded to the design of the demand charges, using EPE's incremental capacity cost, for most rate classes, to recognize seasonal cost

[16] For example, the standard service under the Residential Service Schedule No. 01, Small General Service Schedule No. 02, Irrigation Service Schedule No. 22, General Service Schedule No. 24, and City and County Service Schedule No. 41, currently define the summer season as the months from May through October of each year.

differences for generation costs. EPE limited its proposed seasonal demand charges at the estimated cost of service, so that demand charges will not collect more than 100% of the demand-related costs as indicated by its embedded class cost of service study.

Lastly, EPE designed the volumetric rates for both non-TOD and TOD service, either for mandatory rates or optional rates when applicable. In general, volumetric rates were designed to provide a more homogenous seasonal pricing among rate classes, with a resulting total summer to non-summer price ratio in the 1.2 and above range, while at the same time, using marginal costing information to determine a reasonable peak-to-off-peak price ratio that would reflect the incremental capacity costs in the Summer on-peak period rates. The volumetric rates were the "catch-all" price category, that would include any costs not recovered through the customer or demand-related components, to arrive at the total revenue requirement by rate class as proposed by EPE in this case.

Q. OVERALL, WHAT IS THE END RESULT OF EPE'S PROPOSED CHANGES TO SEASONS AND PRICE DIFFERENTIALS BETWEEN SUMMER AND NON-SUMMER OFF-PEAK PERIODS?

A. All the proposed changes to EPE's current rate structures mentioned above will provide customers with an improved pricing structure that better reflects the differences and variations in electricity costs throughout the year and, therefore, provide more accurate and effective price signals. The changes to EPE's pricing structures proposed in this case will allow customers to make economic decisions about their electric usage based on rates that more accurately reflect the underlying costs and that will provide economic incentives to conserve energy and potentially improve the utilization of EPE's electric grid by increasing the overall system load factor.

Q. HOW DO THE PROPOSED RATES PROVIDE EPE WITH AN OPPORTUNITY TO RECOVER ITS COST?

A. As demonstrated by Schedule Q-7, Proof of Revenues, the proposed rates are designed to recover EPE's proposed revenue requirement in this case. The Test Year billing determinants employed in developing rates have been adjusted as discussed in Section III of this testimony and accurately reflect the way customers will be billed once the proposed rates go into effect.

As explained above, EPE's overall rate design approach for all rate classes is to move the monthly customer charge and demand charges toward cost-based levels as well.

Q. HAS EPE PREPARED COMPARISONS OF CURRENT AND PROPOSED RATES AND IMPACTS ON CUSTOMERS?

A. Yes. Exhibit MC-6 compares the proposed base rates to current base rates for each customer class and shows the percentage changes to those rates. In addition, I provide several exhibits which analyze the bill impact of proposed rates for particular rate classes and customer groups.

Q. IN ADDITION TO REVISING THE APPLICABLE BASE RATES, IS EPE PROPOSING ANY OTHER CHANGES TO ITS RETAIL TARIFFS IN THIS RATE CASE?

A. Yes. EPE is proposing language revisions to multiple tariffs. A more detailed discussion about these changes is provided in Schedule Q-4.2 and discussed in Section VII of this testimony.

1. Customer Charges

Q. WHAT IS EPE'S RATIONALE TO PROPOSE IN THIS CASE THE FULL RECOVERY OF THE CUSTOMER-RELATED COSTS FROM CUSTOMER CHARGES FOR SOME CLASSES?

A. As explained above, this proposal is intended to mitigate intra-class subsidization and provide all customers with better price signals. For example, if a significant portion of fixed costs are recovered through volumetric energy charges, that is, costs that do not vary with the amount of energy or kWh used such as customer-related costs, customers who reduce their usage avoid paying those fixed costs incurred to provide service to them. Unless costs are recovered through appropriate fixed charges and variable energy charges, other customers in the class bear the portion of the fixed costs avoided by customers who install energy efficiency measures, purchase distributed renewable generation, or otherwise reduce their energy consumption.

Customer-related costs are associated with maintaining the customer on the EPE system and can be characterized generally as costs related to the metering and billing functions, and to providing customer service. The important characteristic here is that these costs do not vary based on the energy consumption of the customer.

Q. DOES INCREASING THE CUSTOMER CHARGES MEAN THAT EPE WILL BE ABLE TO RECOVER ALL OF ITS FIXED COSTS ALLOCATED TO RATE CLASSES?

A. No. Because several rates, such as Residential rates, are assessed to customers using a fixed monthly customer charge and volumetric rates per kWh of electricity used to recover all other costs (also known as a two-part tariff) including generation, transmission, and distribution system costs.

Q. WHY IS IT IMPORTANT TO ESTABLISH CUSTOMER CHARGES THAT ARE COST-BASED OR THAT MOVE CLOSER TOWARDS COST-BASED LEVELS FOR ALL CUSTOMER CLASSES?

A. Increasing the customer charges to full cost of service, where possible, reduces intra-class subsidies and improves the accuracy of the price signal provided by other charges, particularly the volumetric energy charge. Intra-class subsidization for customer-related costs can occur when the customer charge does not reflect 100% of the costs. That is because any customer-related costs not recovered through the customer charge, are normally recovered from the volumetric rates. Thus, everything else being equal, higher-than-average usage customers would pay an amount higher than the cost-based level towards customer-related costs; lower-than-average usage customers, would pay an amount less than the cost-based level towards customer-related costs, creating the intra-class subsidy referenced above. The higher-than-average usage customer would be subsidizing the lower-than-average usage customer with regard to customer-related costs.

Q. IN YOUR OPINION, WILL EPE'S PROPOSED INCREASES TO CUSTOMER CHARGES HAVE A LARGE BILL IMPACT ON CUSTOMERS?

A. Not likely. For the Residential Service rate class, the proposed customer charges represent approximately 12% of the base rate charges, which also means that residential customers will keep control over more than 87% of their monthly bill. For low income customers, that qualify for the Low Income Rider, the customer charge will represent 0% of their monthly bill. This relative impact of customer charges on residential customers' bills is lessened further when other rates and riders are taken into account when calculating the customers' bills.

2. Peak and Off-Peak Seasons

Q. WHY IS EPE PROPOSING TO CHANGE THE SUMMER SEASON TO BE UNIFORMLY DEFINED AS THE MONTHS OF JUNE THROUGH SEPTEMBER ACROSS ALL CUSTOMER CLASSES?

A. EPE's proposal to reduce in some instances the number of months included in the summer season aligns the pricing structures offered in Texas with EPE's summer season and system peak hours. Doing so provides a stronger price signal during times when EPE's system generally experiencs its peak demands. A 4-month summer season for billing purposes will also align with the time period that supports the allocators used for the assignment of generation and transmission costs to rate classes as explained in more detail in the Direct Testimony of EPE witness Hernandez. Having a shorter, more uniform and clearly defined "peak" summer season, applied consistently across most customer classes, will convey to customers more transparent and stronger price signals.

3. Time-of-Day (TOD) On-Peak Period Hours

Q. IS EPE PROPOSING TO CHANGE THE ON-PEAK PERIOD HOURS FOR TOD SCHEDULES TO ALIGN WITH THE HOURS THAT EPE'S SYSTEM EXPERIENCES IT HIGHEST LOADS?

A. No. EPE has determined that during the summer weekdays, the electric system is approximately 24 times more likely to peak between 6:00 P.M. and 7:00 P.M., than between 12:00 P.M. and 1:00 P.M., which warrants a change in the on-peak period applicable to TOD tariffs. However, with the eminent change in the AMS metering technology that EPE recently filed an application with the Commission for approval to implement across its service area, EPE determined that it is not cost effective to propose a change to the on-peak period hours in this proceeding. This is due to the amount of programming that is required on its current time-of-use meters, which will soon be replaced with AMS meters.

4. Demand Charges

Q. WHAT IS EPE'S RATIONALE FOR THE RECOVERY OF DEMAND-RELATED COSTS FROM DEMAND CHARGES?

A. EPE's goal in determining demand charges is to propose charges that align cost causation with cost recovery, that is, demand charges that more closely reflect all the underlying demand-related costs, such as those associated with the generation, transmission, substations, primary, and secondary distribution systems. Furthermore, in setting demand charges, EPE is also taking into consideration the seasonal bill impacts of those changes to demand charges in the affected classes, especially for customers with different load factors and seasonal usage within each customer class. Therefore, EPE's proposed demand charges to collect different amounts of demand-related costs by rate class balance the stated goal of aligning cost with rates and the potential seasonal bill impacts within each customer class under a three-part tariff (i.e., with customer, demand and energy charges).

In other non-residential rate classes, these types of costs are generally recovered through a demand charge applied to the billed kW or maximum load drawn by customers in any given month. Because electric systems are built and sized to meet the electric needs of customers at every point in time, including periods when electricity demand reaches its maximum, demand charges allow utilities to recover these fixed costs through a rate element that more accurately reflects the way these costs are incurred to meet the customers' instantaneous demand. In EPE's rate structures, these demand charges are assessed to customers based on their highest level of electric usage at any given moment during each billing period, a demand ratchet based on the customer's load during the summer months, or a minimum demand specified in the rate schedule.

Q. IS EPE PROPOSING FULL COST-OF-SERVICE DEMAND CHARGES FOR RESIDENTIAL AND SMALL GENERAL SERVICE?

A. No. At this time, EPE is proposing demand charges for the Residential and Small General Service optional demand charge rate option that reflects only the distribution-related costs (i.e., the costs associated with the secondary voltage distribution system).

Q. WHY IS EPE PROPOSING TO CHARGE HIGHER DEMAND CHARGE RATES DURING THE SUMMER OFF-PEAK PERIOD WHEN COMPARED TO NON-SUMMER OFF-PEAK PERIODS?

A. A higher demand charge rate during the summer off-peak hours will provide customers with better price signals by recognizing the higher loads experienced on average during the off-peak hours in the summer months, when compared to off-peak hours in the non-summer months. Also, assessing a moderately higher price during all the summer months could encourage customers to invest in energy efficiency and conservation targeting summer usage and obtain a faster payback on their investment, while helping reduce the peak loads experienced in the summer season, which is normally the time of the year when growth in demand over time may trigger the need for additional generation capacity.

5. Non-TOD Energy Charges

Q. WHAT FUNDAMENTAL APPROACH DID EPE TAKE IN CALCULATING THE NON-TOD ENERGY CHARGES?

A. EPE's approach in calculating the non-TOD energy charges was to ensure that those charges provide a strong pricing signal toward conservation during the summer months. Another potential consequence of this stronger pricing signal is to reduce the loads that have contributed to EPE's declining load factor. EPE witness Novela addresses the declining load factor in his direct testimony.

Q. DON'T EPE'S CURRENT NON-TOD ENERGY CHARGE STRUCTURES ALREADY PROVIDE THIS CONSERVATION PRICING SIGNAL?

A. Most of them do. However, the energy charge rate structures of Schedule Nos. 24 and 41 is in the form of a declining-block structure. This means that the average price declines as energy consumption increases. Schedule No. 41's current rate structure exhibits this average price decline most profoundly and militates against achieving energy efficiency and conservation goals.

6. TOD Energy Charges

Q. HOW WERE THE ON-PEAK PERIOD AND OFF-PEAK PERIOD ENERGY CHARGES CALCULATED?

A. The on-peak period energy price adder, which is the incremental charge for consumption during the on-peak period hours, was designed to recover a percentage of EPE's incremental capacity cost of $113.81 per kW-year. This amount was divided by the average consumption for the rate class during the proposed on-peak period hours to derive the on-peak period energy price adder per kWh. The on-peak period energy price adder is added to the Off-Peak Period Energy Charge to produce the On-Peak Period Energy Charge. The percentage of total incremental capacity cost differs by rate class. The Off-Peak Period Energy charge per kWh was calculated to recover the remaining cost that is not recovered through the Customer, Demand, and On-Peak Period Energy Charges. The Off-Peak Period Energy Charge is applicable during all other hours of the year.

Q. HOW DID EPE DETERMINE THE INCREMENTAL CAPACITY COST OF $113.81 PER KW-YEAR?

A. In EPE's most recent rate cases in Texas and New Mexico, EPE relied on the costs for the Rio Grande Unit 9 combustion turbine to estimate the incremental capacity cost used in rate design, and thus, EPE used that unit's levelized costs in this base rate case filing for consistency purposes. This is consistent with the electric utility industry where the cost of a combustion turbine has been used as a proxy for the marginal generation costs. Development of the incremental capacity cost is shown in Workpaper Q-7(a).

Q. PLEASE EXPLAIN WHY THE ON-PEAK PERIOD ENERGY PRICE ADDER IS BASED ON PERCENTAGES OF THE INCREMENTAL CAPACITY COST THAT DIFFER BY RATE CLASS.

A. The percentages of EPE's incremental capacity cost by class that the TOD on-peak period energy price adders are based on, are a part of EPE's tools in its rate design process. In balancing gradualism, as well as developing On-Peak Period Energy Charges with the intent to influence certain consumption behaviors, it is necessary that the percentages differ among rate classes. If the percentages are set too high, rate shock is introduced and if the percentages are set too low then the intended effect of the on-peak period charges will be insufficient. The on-peak energy price adders by rate class, along with the percentages can be found in EPE's rate design model, Workpaper Q-7(a).

Q. WHY IS EPE PROPOSING TO CHARGE HIGHER ENERGY CHARGE RATES DURING THE SUMMER OFF-PEAK PERIOD WHEN COMPARED TO NON-SUMMER OFF-PEAK PERIODS?

A. As discussed above for seasonal demand charges, a higher energy charge rate during the summer off-peak hours will provide customers with better price signals by recognizing the higher loads experienced on average during the off-peak hours in the summer months, when compared to off-peak hours in the non-summer months.

Q. WHAT IS EPE'S APPROACH TO CALCULATE THE OPTIONAL TOD RATES?

A. The optional TOD rates were designed to be revenue neutral relative to the annual charges under the standard service rate. This approach will result in the annual rate class base-rate revenue to be the similar amount whether all customers in the rate class choose to take service under the standard rate or under the TOD rate.[17] Revenue neutrality results from comparing the total "annual" non-fuel revenue allocated to the class, either for the Standard or the Optional TOD rate designs. More importantly, the revenue neutrality between the Standard and Optional TOD rates applies to the "average" annual bill and not to each month or season.

VII. Rate Schedule Revisions

A. Overview

Q. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?

A. In this section of my testimony, I discuss the more significant revisions to EPE's existing rate schedules that are proposed in this proceeding. A detailed discussion about changes to each rate schedules is provided in Schedule Q-4.2.

[17] Although the approach is to make the revenues "neutral" between standard and optional rate options, due to rounding, the amounts will not necessarily be equal.

Q. IN ADDITION TO REVISING THE APPLICABLE BASE RATES AND STRUCTURES, IS EPE PROPOSING ANY OTHER SIGNIFICANT CHANGES TO ITS RETAIL RATE SCHEDULES IN THIS RATE CASE?

A. Yes. EPE is proposing language changes to clarify and improve the structure of the rate schedules and better align the language between certain rate schedules applicable in EPE's Texas and New Mexico service territories to ensure consistency in the criteria applied to the electric service in both service territories.

Q. ARE THERE ANY LANGUAGE CHANGES APPLICABLE TO ALL OR MOST PROPOSED RATE SCHEDULES?

A. Yes. There are four language changes applicable to all or most of the proposed rate schedules: (1) where applicable, the description of all "Time-Of-Use" (TOU) rates will be changed to "Time-Of-Day" (TOD), (2) the addition of a provision to signify that each rate schedule may be subject to other riders, (3) the addition of a new provision for certain rate schedules that bill calculations are subject to proration adjustments, and (4) clarification of the definition of maximum demand for rate schedules that include a determination of a billing demand provision.

Q. WHAT IS THE EFFECT OF RENAMING A "TIME-OF-USE" RATE TO "TIME-OF-DAY"?

A. The tariff language change of descriptions from "Time-Of-Use (TOU)" to "Time-Of-Day (TOD)" is intended to better communicate and promote time varying rates to current and potential customers, particularly residential customers. The industry trend is to use TOD, which is a concept that customers can more easily grasp when considering rates that are charged based on the time of the day.

Q. WHAT IS THE PURPOSE OF ADDING A GENERAL REFERENCE TO ALL APPLICABLE RIDERS?

A. Adding a general reference to all applicable riders that the rate schedule could be subject to reduces the administrative effort of revising each rate schedule as riders are implemented.

Q. EXPLAIN THE PROPOSED PRORATION PROVISION.

A. This new provision is to explain that the service under a rate schedule is subject to proration of the bill calculations under each service. This provision simply formalizes in the rate schedule a process that EPE already has in place. Proration of bill calculations is common for utility services and is intended to bill customers more fairly for service under rates that are designed on monthly billing determinants. For example, proration may occur when (1) a new service is begun in between normal billing periods, (2) service is terminated between normal billing periods, and (3) a change in rate options is made during normal billing periods. For example, demand charges are designed as a dollar amount per kW month, say $12.00/kW month. In this example, if a new customer signs up for utility service in the middle of a normal billing month, then the demand charge for that billing month will be based on $6.00 per kW. Another example is for consumption-based charges, an energy charge. EPE's residential rate schedule uses a two-tier block structure to bill for energy consumption: The first 600 kWh during a normal billing period is priced at a certain rate, and all kWh exceeding 600 kWh is priced at a higher rate. If a customer starts service in the middle of a billing period, then the first tier is prorated to 300 kWh for that billing month.

Q. WHY IS IT NECESSARY TO CLARIFY THE MAXIMUM DEMAND DEFINITION?

A. In the determination of billing demand of the rate schedules that contain a demand charge, maximum demand is currently defined as the highest measured average kW load over some period of time (typically thirty minutes). Some customers have interpreted this definition as an average of all the thirty-minute intervals in the billing cycle

EPE is proposing to replace the term "average" with "interval" and ensure the phrase "during the billing period" is appended to the definition sentence. The definition of maximum demand in the determination of billing demand provision, therefore, is revised to clarify that it is based on the highest measured interval kW (i.e., one data point, not all thirty-minute readings) instead of the highest measured average. This method of calculating maximum demand is currently applied in EPE's metering configuration, thus it has no impact under the proposed rate schedule. This clarification of the maximum demand definition is made to all rate schedules that include such definition.

Q. HAVE YOU PROVIDED COPIES OF THE PROPOSED RATE SCHEDULES?

A. Yes. EPE's proposed rate schedules are presented in RFP Schedule Q-8.8.

Q. WHEN WERE EPE'S CURRENTLY EFFECTIVE BASE-RATE SCHEDULES APPROVED AND IMPLEMENTED?

A. EPE's currently effective base-rate schedules were approved in PUCT's Final Order in Docket No. 46831 ("2017 Rate Case") on December 18, 2017. They became effective July 18, 2017, but were implemented for billing on January 1, 2018.

1. Schedule No. 01 – Residential Service

Q. PLEASE DESCRIBE THE EXISTING SCHEDULE NO. 01 – RESIDENTIAL SERVICE RATE SCHEDULE.

A. This rate schedule is applicable to single-family residences or individually metered apartments for primarily domestic or home use. The rate schedule includes three monthly rate options: a Standard Service Monthly Rate, an Alternate Time-Of-Use (TOU) Monthly Rate, and an Experimental Distributed Generation Demand Charge Monthly Rate. A clause is included that offers bill protection to the first 500 customers that elect to take service under the TOU Monthly Rate for an initial twelve-month period under that rate option.

The rate schedule also includes a provision for a monthly minimum charge, including special charges applicable to distributed generation ("DG") customers. It also includes reference to other applicable riders, as well as terms and conditions that apply to service under this schedule. Other provisions currently offered under Schedule No. 01 include an Off-Peak Water Heating Rider, which is closed to new service applications, and a Low Income Rider.

Q. PLEASE DESCRIBE THE EXISTING STRUCTURE OF RATES OFFERED UNDER SCHEDULE NO. 01.

A. The Standard Service Monthly Rate structure consists of a monthly Customer Charge and seasonal, inclining two-block Energy Charges. The inclining block rate structure applies in the six summer months of May through October. The first block of the summer Energy

Charge includes a one cent per kWh price differential over the winter Energy Charge. The second block of the summer Energy Charge includes a half cent per kWh price differential over the first block.

The Alternate TOU Monthly Rate consists of a monthly Customer Charge and Energy Charges that apply based on the month, day, and hour that usage occurs. The On-Peak Period Energy Charge applies from noon to 6:00 P.M. Mountain Daylight Time (unless otherwise indicated, all times listed are Mountain Daylight Time) weekdays during the summer season, and the Off-Peak Period Energy Charge applies during all other hours of the year. Like EPE's other TOU rates, the summer season is defined as June through September.

The Experimental Distributed Generation Demand Charge Monthly Rate consists of a monthly Customer Charge, a flat Demand Charge, and Energy Charges that apply based on the month, day, and hour that usage occurs. The On-Peak Period Energy Charge applies from noon to 6:00 P.M. Mountain Daylight Time (unless otherwise indicated, all times listed are Mountain Daylight Time) weekdays during the summer season, and the Off-Peak Period Energy Charge applies during all other hours of the year.

Q. WHAT SIGNIFICANT LANGUAGE CHANGES ARE PROPOSED FOR SCHEDULE NO. 01?

A. EPE proposes to make the Experimental Distribution Generation Demand Charge Rate available to all customers served under this rate schedule. Thus, the term "Distributed Generation" is removed from the description of this rate option. Additionally, the monthly minimum charge applicable to DG customers is consolidated to one minimum charge rather than the current two. Finally, clarifying language is added to the type of service and the terms and conditions provisions.

Q. WHAT RATE CHANGES DOES EPE PROPOSE FOR SCHEDULE NO. 01 RATES AND RATE STRUCTURES?

A. For the Standard Service Rate, EPE is proposing to:

(1) set the monthly Customer Charge to collect all the customer-related costs;

(2) shorten the summer season from six months (May through October) to four months (June through September);

(3) increase the price differential between summer and non-summer Energy Charges; and

(4) to the extent possible, increase the price differential between the first and second blocks of the summer Energy Charges.

For the TOD Rate, EPE is proposing to:

(1) set the monthly Customer Charge equal to the Standard Service Rate monthly Customer Charge;

(2) set the non-summer Energy Charge equal to the Standard Service Rate non-summer Energy Charge; and

(3) to the extent possible, increase the price differential between On-Peak Period and Off-Peak Period summer Energy Charges.

For the Experimental Demand Charge Rate, EPE is proposing to:

(1) set the monthly Customer Charge equal to the Standard Service Rate monthly Customer Charge;

(2) set the Demand Charge to reflect only the distribution-related cost, at full-cost;

(3) set the non-summer Energy Charge equal to the Standard Service Rate non-summer Energy Charge, less an amount commensurate to the distribution-related costs recovered through the Demand Charge; and

(4) to the extent possible, increase the price differential between On-Peak Period and Off-Peak Period summer Energy Charges.

Exhibit MC-6 provides a comparison of current and proposed rate components for each of the rate options of all the proposed rate schedules.

Q. WHY IS EPE PROPOSING TO INCREASE THE CUSTOMER CHARGE FOR THE RESIDENTIAL SERVICE RATE?

A. As noted previously, charges that reflect the cost of providing service communicate accurate price signals to customers. EPE is proposing to increase the monthly Customer Charge for Residential Service from $8.25 to $10.54 to reflect customer-related costs more accurately for Residential Service customers. These are costs that are associated with maintaining the customer on the EPE system and can be characterized generally as costs related to the metering and billing functions, and to providing customer service. The important characteristic here is that these costs do not vary as a function of the energy consumption of the customers.

Q. HOW DOES EPE'S CURRENT AND PROPOSED CUSTOMER CHARGE FOR THE RESIDENTIAL SERVICE RATE NO. 01 COMPARE TO OTHER NON-ERCOT INVESTOR-OWNED UTILITIES IN TEXAS?

A EPE's current residential Customer Charge is $8.25 per meter/month for the Standard Service Rate option and proposed at $10.54. EPE's current charge is currently the second lowest among investor owned electric utilities in Texas, when compared to Entergy's $10.00,[18] Southwestern Electric Power Company's $8.00,[19] and Xcel Energy Texas' (or Southwestern Public Service) $10.50.[20] Therefore, EPE's proposed cost-based Customer Charge for the Schedule No. 01 is within a zone of reasonableness when compared to other monthly charges for residential electric service in Texas.

Q. DOES INCREASING THE RESIDENTIAL CUSTOMER CHARGE MEAN THAT EPE WILL BE ABLE TO RECOVER ALL OF ITS FIXED COSTS ALLOCATED TO THIS RATE CLASS?

A. No. Because the Residential rates, and several other rates, are assessed to customers using a fixed monthly Customer Charge and volumetric rates per kWh of electricity used (also known as a two-part tariff), all other fixed costs incurred to serve these customers, such as generation, transmission, and distribution costs, will be recovered from the variable Energy Charge in customers' bills.

Q. WHY IS EPE PROPOSING TO INCREASE THE PRICE DIFFERENTIAL BETWEEN

[18] Schedule RS, Residential Service, effective for service on and after 10-17-18. Accessed on May 5, 2021 at https://cdn.entergy-texas.com/userfiles/content/price/tariffs/eti_rs.pdf?_ga=2.260254093.1427452262.1620243496-1085871750.1598978337

[19] Schedule Residential Service (RS), effective for service on December 20, 2018. Accessed on May 5, 2021 at https://www.swepco.com/lib/docs/ratesandtariffs/Texas/Texas%20Rates%20Charges%20and%20Fees%2002-14-2020.pdf

[20] Residential Service, effective for service on January 10, 2020. Accessed on May 5, 2020 at https://www.xcelenergy.com/staticfiles/ccqr/Knowledgebase/Rates/tx_sps_e_entire.pdf

SUMMER AND NON-SUMMER ENERGY CHARGES?

A. Also, as noted previously, EPE is proposing rate structures that encourage energy conservation and potentially reduce customers' contribution to EPE's system peak. Seasonal Energy Charges are useful to send pricing signals that communicate the higher production and transmission-related operating costs that have been incurred by EPE to meet the summer months loads. The price differential between the Standard Service Rate summer first block and the non-summer Energy Charge is proposed to increase to two cents from the current one cent differential to provide a stronger price signal for the proposed four-month summer season.

Q. WHY IS EPE PROPOSING TO INCREASE THE PRICE DIFFERENTIAL BETWEEN THE FIRST AND SECOND BLOCKS OF THE SUMMER ENERGY CHARGES?

A. Like the purpose of seasonal Energy Charges, an inclining-block structure intends to encourage energy conservation and potentially reduce customers' contribution to EPE's system peak. The price differential between the Standard Service Rate summer first and second block Energy Charge is proposed to increase to a full cent from the current half cent differential.

Q. HAS THE COMPANY ADJUSTED BILLING DETERMINANTS FOR ENERGY CONSERVATION AND POTENTIAL REDUCTION IN THE CUSTOMERS' CONTRIBUTION TO EPE'S SYSTEM PEAK AS A RESULT OF THE INCREASED PRICE DIFFERENTIALS?

A. No. Although the increase in the price differentials are expected to result in customers modifying their consumption behavior, price elasticity data specific to EPE is not available to make any reasonable estimation of an adjustment to billing determinants of any rate.

Q. HAS THE COMPANY ANALYZED THE IMPACT OF THE PROPOSED STANDARD SERVICE RATES ON RESIDENTIAL SERVICE CUSTOMERS WITH VARIOUS USAGE CHARACTERISTICS?

A. Yes. RFP Schedule Q-8.9 provides bill impacts based on various levels of electric usage. The monthly bill impact of the higher Customer Charge and the increase to the Energy

Charge in the summer months is mitigated to some extent by EPE's proposed rate structure. The proposed rate structure provides a lower Energy Charge for kWh consumption in non-summer months, which is proposed to be an eight-month period instead of the current six-month period. This change results in an appropriately higher rate for energy consumption for higher use in the summer, the period when EPE experiences its system peak load and when growth in peak demand over time requires additional capacity. The combined result of this rate structure change is rates that more accurately reflect the cost of providing service across the Residential class.

Q. WHAT IS THE IMPACT OF THIS RATE STRUCTURE ON LOW INCOME RIDER CUSTOMERS?

A. EPE's existing Low Income Rider under Schedule No. 01 provides for a waiver of the monthly Customer Charge for qualifying customers. Because EPE is not proposing any change to the provisions of the existing rider, the impact of the higher Customer Charge is to increase the discount provided under the rider.

Q. WILL THE INCREASE IN THE CUSTOMER CHARGE FOR THE RESIDENTIAL SERVICE RATE AFFECT THE CUSTOMERS' ABILITY TO CONTROL THEIR ENERGY USAGE?

A. No. Even with the proposed monthly Customer Charge, residential customers are still able to maintain control of their electric bill by managing energy consumption and taking advantage of opportunities aimed at reducing their energy usage through energy efficiency programs or conservation. Under EPE's proposed residential rate design, for most customers the predominant charge on the customer's bill will still be the volumetric Energy Charge, which is under the customer's control.

Q. HAS THE COMPANY COMPARED THE RESIDENTIAL BILLS UNDER CURRENT AND PROPOSED STANDARD SERVICE RATES BY BILL COMPONENT?

A. Yes. Exhibit MC-7 shows a comparison of monthly residential bills, using the average Residential monthly consumption for the Test Year of 686 kWh. As shown in the exhibit's Chart 1, for non-summer months, the bills under proposed rates is roughly $73 under the proposed rates, compared to $63 under current rates. For summer months, the bills under proposed rates are roughly $153 under the proposed rates, compared to $116 under current rates.

The exhibit's Chart 2 provides the change in average bill for each month. For low average usage months, the increase in electric bills is slightly less than $6. For higher average usage months, the bills are roughly $21 more per month, indicating a pricing signal to encourage power conservation. An interesting observation in the graph is the low bill impact for May and October, which are months that are now non-summer months in EPE's proposed rate structure.

Q. WHAT CHANGES ARE PROPOSED FOR THE RESIDENTIAL TOD RATE OPTION?

A. EPE is proposing to set the customer charge equal to proposed Standard Service Rate customer charge. As explained previously, recovering these customer costs in the most appropriate manner means that the TOD Energy Charges offered under the rate provide accurate price signals.

In addition, the non-summer Energy Charge for the TOD Rate is also set equal to the proposed non-summer Energy Charge for the Standard Service Rate. This is because there is no reason for TOD customers to receive the benefit of a lower Energy Charge as compared to non-TOD customers during non-summer months, when EPE's system has sufficient capacity to serve both types of customers.

Finally, the Company is proposing to modify the On-Peak Period to Off-Peak Period Charge differential to reflect EPE's current generation costs. The on-peak periods and off-peak periods of the existing TOD option will remain unchanged.

Q. HOW DO EPE'S PROPOSED TOD RATES FOR ITS RESIDENTIAL CUSTOMERS COMPARE TO OTHER SIMILAR TIME-VARIANT RATE OFFERINGS IN THE COUNTRY?

A. A recent survey report published by The Brattle Group on Residential Time-Of-Use (or TOD) rates offered by electric utilities found that the median on-peak period to off-peak period price ratio for TOD rates is 2.7-to-1, where 71% of the TOU rates have a price ratio of at least 2-to-1; and for TOU rates designed recently (i.e., those developed for pricing pilots in the past decade) typically have a peak period of six hours or less. EPE's proposed on-peak period to off-peak period ratio is in fact much higher, at 3.34-to-1 (slightly up from the current 3.09-to-1 ratio), with a peak period of six hours. Therefore, EPE's proposed TOD price signals for Residential customers are in line with many other time-variant rate offerings in the country and provide a reasonable economic incentive for customers to consider participation in the TOD rate offering and to change their usage patterns.

Q. HOW HAS EPE ENCOURAGED PARTICIPATION IN THE TOD OPTION?

A. EPE's Schedule No. 01 offers a bill protection clause that removes the risk of severe bill impact in the initial twelve months after a customer switches to the TOD option. If, at the conclusion of the initial 12-month period of service under the TOU option, the total billings exceed billings for the same period under the Standard Service rate, the customer may opt to revert to the Standard Service rate. In this event, the Company will reset the customer's account to the Standard Service rate and provide a credit to the customer for the difference in billings under the TOU option and the Standard Service rate for the 12-month review period.

This bill protection provision is limited to the first 500 new customers to enroll in TOU, as it is necessary to first gauge how such rates will be received by customers and to ensure the Company has the resources available to timely prepare analyses for each customer. Limited participation will help EPE determine whether adjustments in the rates can help make the TOU option attractive to additional participants. EPE proposes to maintain this provision in the schedule as-is.

Q. WHAT CHANGES ARE PROPOSED FOR THE EXPERIMENTAL OPTIONAL DEMAND CHARGE RATE?

A. EPE is proposing to set the customer charge equal to the proposed Standard Service Rate Customer Charge. The rate structure will maintain the flat Demand Charge per kW applicable in all months. The Demand Charge will be complemented with Energy Charges that account for the recovery of the distribution-related costs of the Residential Service rate class through the Demand Charge. In addition, the Company is proposing to modify the On-Peak Period to Off-Peak Period Energy Charge differential to reflect EPE's current incremental capacity costs. The on-peak periods and off-peak periods of the existing Experimental Demand Charge Rate option will remain unchanged.

Q. WHY IS THE EXPERIMENTAL DEMAND CHARGE RATE OFFERED AS AN EXPERIMENTAL RATE OPTION?

A. Residential demand charge rates are not very common, although some utilities have had them in place for several years. As an optional offering to EPE residential customers, it is necessary to first gauge how such rates will be received by customers, therefore, EPE proposes to limit participation to only 500 customers at this time. Limited participation will help EPE determine whether adjustments in the rates can help make this option attractive to additional participants.

In other non-residential rate classes, these demand-related costs are generally recovered through a demand charge applied to the billed kW or maximum load drawn by customers in any given month. Because electric systems are built and sized to meet the electric needs of customers at every point in time, including periods when electricity demand reaches its maximum, demand charges allow utilities to recover these fixed costs through a rate element that more accurately reflects the way these costs are incurred to meet the customers' instantaneous demand. In EPE's rate structures, these demand charges are assessed to customers based on their highest level of electric usage at any given moment during each billing period.

Q. PLEASE ELABORATE ON THE MONTHLY MINIMUM CHARGE PROVISION.

A. The monthly minimum charge provision in the currently effective Schedule No. 01 was implemented because of the settlement stipulation in EPE's 2017 Texas Rate Case, Docket No. 46831. For non-DG customers and grandfathered DG customers, the Monthly Minimum Charge is the Customer Charge. For non-grandfathered DG customers, the Monthly Minimum Charge depends on which Schedule No. 01 rate option they select to take service under. Discussion of the grandfathering provision was included in Attachment 7 of the stipulation and agreement in Docket No. 46831.

Q. HOW WERE CHARGES APPLICABLE TO NON-GRANDFATHERED DG

CUSTOMERS IN THE MONTHLY MINIMUM CHARGE PROVISION DETERMINED?

A. Those charges were the result of the settlement stipulation negotiations. One component of the Monthly Minimum Charge is the Customer Charge that all Schedule No. 01 customers are subjected to.

Q. IS EPE PROPOSING TO REVISE THE MONTHLY MINIMUM CHARGES APPLICABLE TO NON-GRANDFATHERED DG CUSTOMERS? IF SO, PLEASE EXPLAIN THE RATIONALE FOR THE REVISED CHARGES.

A. Yes. The proposed Monthly Minimum Charge applicable to DG customers that are not taking service under the Experimental Demand Charge Rate will be based on (1) the proposed Customer Charge, and (2) like the Demand Charge of the Experimental Demand Charge Rate, the distribution system-related costs for the Residential Service rate class coupled with the average non-coincident demand for that rate class. A monthly minimum charge applicable to DG customers ensures that these customers contribute toward the cost of EPE's distribution system that serves them.

Q. WHAT CHANGES DOES THE COMPANY PROPOSE TO THE OFF-PEAK WATER HEATING SERVICE RIDER?

A. EPE is proposing to increase the monthly Customer Charge from $2.56 to the full cost of $4.84 per month. In addition, as discussed previously, EPE is also proposing an increase in the Energy Charge for this service to recover the cost of serving Off-Peak Water Heating Service Rider customers more adequately.

2. Schedule No. 02 – Small General Service Rate

Q. PLEASE DESCRIBE THE EXISTING SCHEDULE NO. 02 – SMALL GENERAL SERVICE RATE SCHEDULE.

A. This rate schedule is applicable to customers with peak demand not exceeding 15 kW monthly. The rate schedule includes three monthly rate options: a Standard Service Monthly Rate, an Alternate TOU Monthly Rate, and an Experimental Demand Charge Monthly Rate. A clause is included that offers bill protection to the first 150 customers that elect to take service under the TOU Monthly Rate for an initial twelve-month period under that rate option.

The rate schedule also includes provisions for determination of billing demand and for a Monthly Minimum Charge, including special applicable charges to DG customers. It also includes a reference to other applicable riders, as well as terms and conditions that apply to service under this schedule. Other rate provisions currently offered under Schedule No. 02 include an Off-Peak Water Heating Rider, which is closed to new service applications, and a provision for non-metered service.

Q. PLEASE DESCRIBE THE EXISTING STRUCTURE OF RATES OFFERED UNDER SCHEDULE NO. 02.

A. The Standard Service Monthly Rate structure consists of a monthly Customer Charge and seasonal Energy Charges in which the summer Energy Charge includes a one cent per kWh price differential over the winter Energy Charge. The summer Energy Charge applies in the six summer months of May through October.

The Alternate TOU Monthly Rate consists of a monthly Customer Charge and Energy Charges that apply based on the month, day, and hour that usage occurs. The On-Peak Period Energy Charge applies from noon to 6:00 P.M. Mountain Daylight Time (unless otherwise indicated, all times listed are Mountain Daylight Time) weekdays during the summer season, and the Off-Peak Period Energy Charge applies during all other hours of the year.

The Experimental Demand Charge Monthly Rate consists of a monthly Customer Charge, a flat Demand Charge, and Energy Charges that apply based on the month, day, and hour that usage occurs. The On-Peak Period Energy Charge applies from noon to 6:00 P.M. Mountain Daylight Time (unless otherwise indicated, all times listed are Mountain Daylight Time) weekdays during the summer season, and the Off-Peak Period Energy Charge applies during all other hours of the year. Similar to EPE's other TOU rates, the summer season is defined as June through September.

Q. WHAT SIGNIFICANT LANGUAGE CHANGES ARE PROPOSED FOR SCHEDULE NO. 02?

A. EPE proposes to make the Experimental Demand Charge Rate available to all customers served under this rate schedule a permanent option. Thus, the term "Experimental" is removed from the description of this rate option. Additionally, the Monthly Minimum Charge applicable to DG customers is consolidated to one minimum charge, rather than the current two. Finally, clarifying language is added to the type of service and the terms and conditions provisions.

Q. WHAT RATE CHANGES DOES EPE PROPOSE FOR THE SCHEDULE NO. 02 RATES AND RATE STRUCTURES?

A. For the Standard Service Rate, EPE is proposing to:

(1) set the monthly Customer Charge to collect all the customer-related costs;
(2) shorten the summer season from six months (May through October) to four months (June through September); and
(3) increase the price differential between summer and non-summer Energy Charges.

For the TOD Rate, EPE is proposing to:

(1) set the monthly Customer Charge equal to the Standard Service Rate monthly Customer Charge;
(2) set the non-summer Off-Peak Period Energy Charge equal to the Standard Service Rate non-summer Energy Charge; and
(3) to the extent possible, increase the price differential between On-Peak Period and Off-Peak Period summer Energy Charges.

For the Demand Charge Rate, EPE is proposing to:

(1) set the monthly Customer Charge equal to the Standard Service Rate monthly Customer Charge;
(2) set the Demand Charge to reflect only the distribution-related cost, at full-cost;
(3) set the non-summer Energy Charge equal to the Standard Service Rate non-summer Energy Charge, less an amount commensurate to the distribution-related costs recovered through the Demand Charge; and
(4) to the extent possible, increase the price differential between On-Peak Period and Off-Peak Period summer Energy Charges.

Exhibit MC-6 provides a comparison of current and proposed rate component for each of the rate options of all the proposed rate schedules.

Q. WHY IS EPE PROPOSING TO INCREASE THE CUSTOMER CHARGE FOR THE SMALL GENERAL SERVICE RATE?

A. EPE is proposing to increase the monthly Customer Charge for Small General Service from \$10.75 to \$12.23. As noted previously, EPE is proposing to increase the Customer Charge to recover its customer-related costs more adequately and to reduce the amount of fixed customer-related costs recovered through the volumetric Energy Charge. This improves the accuracy of the price signal the Small General Service energy rate provides to customers.

Q. WHY IS EPE PROPOSING TO INCREASE THE PRICE DIFFERENTIAL BETWEEN SUMMER AND NON-SUMMER ENERGY CHARGES?

A. Also as noted previously, EPE is proposing rate structures that encourage energy conservation and potentially reduce customers' contribution to EPE's system peak. The price differential between the Standard Service Rate summer and non-summer Energy Charge is proposed to increase to two cents from the current one cent differential.

Q. WHAT CHANGES ARE PROPOSED FOR THE TOD RATE OPTION?

A. EPE is proposing to set the Customer Charge equal to proposed Standard Service Rate Customer Charge as well as to set the non-summer Energy Charge equal to the non-summer Energy Charge for the Standard Service Rate. In addition, the Company is proposing to modify the On-Peak Period to Off-Peak Period Charge differential to reflect EPE's current generation costs. The on-peak periods and off-peak periods of the existing TOD option will remain unchanged.

Q. HOW HAS EPE ENCOURAGED PARTICIPATION IN THE TOD OPTION?

A. Like the Residential Service rate schedule, Schedule No. 02 offers a bill protection clause that removes the risk of severe bill impact in the initial twelve months after a customer switches to the TOD option. The bill protection provision is limited to an initial

150 customers. EPE proposes to maintain this provision in the schedule as-is.

Q. WHAT CHANGES ARE PROPOSED FOR THE OPTIONAL DEMAND CHARGE RATE?

A. EPE is proposing to set the Customer Charge equal to the proposed Standard Service Rate Customer Charge. The rate structure will maintain the flat Demand Charge per kW applicable in all months. The Demand Charge will be complemented with Energy Charges that account for the recovery of the distribution-related costs of the Small General Service rate class through the Demand Charge. In addition, the Company is proposing to modify the On-Peak Period to Off-Peak Period Energy Charge differential to reflect EPE's current generation costs. The on-peak periods and off-peak periods of the existing Experimental Demand Charge Rate option will remain unchanged.

Q. WHY IS THE DEMAND CHARGE RATE OFFERED AS A PERMANENT RATE OPTION RATHER THAN AN EXPERIMENTAL RATE OPTION?

A. Demand charge rates for small usage customers are not very common, although some utilities have had them in place for several years. As an optional offering to EPE small general service customers, it was necessary to first gauge how such rates would be received by customers. At the Test Year-end, 528 customers participated under the Experimental Demand Charge Rate option, indicating a good interest in this rate option. Therefore, EPE proposes to convert the Experimental Demand Charge Rate option to a permanent rate option under Schedule No. 02.

Q. HAS EPE PROPOSED THE SAME CHANGES TO THE MONTHLY MINIMUM CHARGE PROVISION OF SCHEDULE NO. 02 AS THOSE DESCRIBED FOR THE MONTHLY MINIMUM CHARGE PROVISION OF SCHEDULE NO. 01?

A. Yes. The cost basis, however, is that of the Small General Service rate class.

Q. ARE THE CHANGES THE COMPANY PROPOSED TO THE OFF-PEAK WATER HEATING SERVICE RIDER IN SCHEDULE NO. 01 THE SAME FOR SCHEDULE NO. 02 OFF-PEAK WATER HEATING SERVICE RIDER?

A. Yes, they are.

3. Schedule No. 07 – Outdoor Recreational Lighting Service Rate

Q. PLEASE DESCRIBE THE EXISTING SCHEDULE NO. 07 – OUTDOOR RECREATIONAL LIGHTING SERVICE RATE.

A. This rate schedule is applicable solely for outdoor recreational lighting installations, such as athletic fields, racetracks, and other sport or recreational facilities. The rate schedule consists of a single rate option and includes provisions that refer to other applicable riders as well as terms and conditions that apply to service under this schedule.

Q. PLEASE DESCRIBE THE EXISTING STRUCTURE OF RATES OFFERED UNDER SCHEDULE NO. 07.

A. The rate structure consists of a monthly Customer Charge and a flat Energy Charge (differentiated by primary and secondary service voltage).

Q. WHAT SIGNIFICANT LANGUAGE CHANGES ARE PROPOSED FOR SCHEDULE NO. 07?

A. No significant language changes are proposed for this rate schedule.

Q. WHAT RATE CHANGES DOES EPE PROPOSE FOR SCHEDULE NO. 07 RATES AND RATE STRUCTURES?

A. EPE is proposing to retain the two-part rate structure and set the monthly Customer Charge to fully collect all the customer-related costs through that charge.

4. Schedule No. 11-TOD – Time-Of-Day Municipal Pumping Service

Q. PLEASE DESCRIBE THE EXISTING SCHEDULE NO. 11-TOU – TIME-OF-USE MUNICIPAL PUMPING SERVICE RATE.

A. This rate schedule is solely applicable to counties, municipalities, and other legal property taxing authorities who receive service for pumping of water, sewage, storm water, and sewage disposal. The rate schedule consists of a single rate option and includes provisions for meter voltage adjustments and that refer to other applicable riders as well as terms and conditions that apply to service under this schedule.

Q. PLEASE DESCRIBE THE EXISTING STRUCTURE OF RATES OFFERED UNDER SCHEDULE NO. 11 – TOU.

A. The rate structure consists of a monthly Customer Charge and Energy Charges (differentiated by primary and secondary service voltage) for three rating periods: on-peak, shoulder-peak, and off-peak. The on-peak period is defined as 1:00 P.M. through 5:00 P.M., Monday through Friday. The shoulder-peak period is defined as 10:00 A.M. through 1:00 P.M. and 5:00 P.M. through 8:00 P.M., Monday through Friday. The off-peak period is comprised of all other hours.

Q. WHAT SIGNIFICANT LANGUAGE CHANGES ARE PROPOSED FOR SCHEDULE NO. 11 – TOD?

A. No significant language changes are proposed for this rate schedule.

Q. WHAT RATE CHANGES DOES EPE PROPOSE FOR SCHEDULE NO. 11– TOD RATES AND RATE STRUCTURES?

A. EPE is proposing to retain the two-part (Customer and Energy Charge) rate structure, including the three rating periods and set the monthly Customer Charge to fully collect all the customer-related costs through that charge.

Q. WHY ARE THE PRICING PERIODS FOR THE MUNICIPAL PUMPING SERVICE TOD RATE DIFFERENT FROM THE ON-PEAK PERIOD FOR OTHER TOD RATES?

A. The pricing periods were developed in cooperation with El Paso Water Utilities several years ago and are designed to provide a strong economic incentive to encourage municipal water pumping loads to reduce consumption during the most critical on-peak hours and to provide a smaller, but still significant, economic incentive to reduce consumption during the shoulder-peak hours.

5. Schedule No. 15 – Electrolytic Refining Service Rate

Q. PLEASE DESCRIBE THE EXISTING SCHEDULE NO. 15 – ELECTROLYTIC REFINING SERVICE RATE.

A. Schedule No. 15 is closed to new service applications and is applicable to existing customers that receive service for electrolytic refining facilities with minimum contracted capacity of 7,500 kW. The rate schedule consists of a single rate option and includes provisions for determination of billing demand, a power factor adjustment, and an interconnection charge. The determination of billing demand includes a 65% demand ratchet. The rate schedule also includes provisions that refer to other applicable riders as well as terms and conditions that apply to service under this schedule.

Q. PLEASE DESCRIBE THE EXISTING RATE STRUCTURE OF SCHEDULE NO. 15.

A. The rate structure consists of a monthly Customer Charge, a seasonal Demand Charge, and a TOD Energy Charge. The summer Demand Charge applies in the four summer months of June through September. The on-peak period is defined as noon through 6:00 P.M., Monday through Friday. The off-peak period is comprised of all other hours.

Q. WHAT SIGNIFICANT LANGUAGE CHANGES ARE PROPOSED FOR SCHEDULE NO. 15?

A. Other than clarifying the Maximum Demand definition, no significant language changes are proposed for this rate schedule.

Q. WHAT RATE CHANGES DOES EPE PROPOSE FOR THE SCHEDULE NO. 15 RATES AND RATE STRUCTURES?

A. EPE is proposing to set the monthly Customer Charge to fully collect all the customer-related costs through that charge. The Demand Charge is set to reflect the underlying demand-related costs of this rate class. The summer Demand Charge reflects a seasonal price differential to recognize that higher loads are experienced on EPE's system in the summer months. The summer Demand Charge includes 25% of EPE's incremental capacity cost and the period includes the remaining amount. The Off-Peak Energy Period Charge is set to recover all costs not recovered through the other rate components.

6. Schedule No. 22 – Irrigation Service Rate

Q. PLEASE DESCRIBE THE EXISTING SCHEDULE NO. 22 – IRRIGATION SERVICE RATE.

A. This rate schedule is applicable solely for irrigation water pumping with loads of 15 kW or larger. The rate schedule includes two monthly rate options: a Standard Service Monthly Rate and an Alternate TOU Monthly Rate. The Standard Service is closed to new service applications. It also includes a reference to other applicable riders as well as terms and conditions that apply to service under this schedule.

Q. PLEASE DESCRIBE THE EXISTING STRUCTURE OF RATES OFFERED UNDER SCHEDULE NO. 22.

A. The Standard Service Monthly Rate structure consists of a monthly Customer Charge and seasonal Energy Charges in which the summer Energy Charge includes a $0.025 per kWh price differential over the winter Energy Charge. The summer Energy Charge applies in the six summer months of May through October.

The Alternate TOU Monthly Rate consists of a monthly Customer Charge and Energy Charges that apply based on the month, day, and hour that usage occurs. The On-Peak Period Energy Charge applies from 1:00 P.M. through 5:00 P.M., weekdays during the summer season, and the Off-Peak Period Energy Charge applies during all other hours of the year.

Q. WHAT SIGNIFICANT LANGUAGE CHANGES ARE PROPOSED FOR SCHEDULE NO. 22?

A. EPE proposes to include a clause that offers bill protection for an initial twelve-month period to all current customers that elect to take service under the TOD Rate. Also, the Standard Service Rate is closed to any irrigation customer that reconnects service.

Q. WHAT WERE THE PARTICIPATION LEVELS IN THE TOD RATE OPTION AT THE END OF THE TEST YEAR?

A. Twenty-five customers took service under the TOD Rate option during the Test Year. EPE hopes the proposed bill protection provision will incentivize the remaining one hundred nineteen customers to elect service under this rate option.

Q. WHAT CHANGES DOES EPE PROPOSE FOR SCHEDULE NO. 22 RATES AND RATE STRUCTURES?

A. For the Standard Service Rate, EPE is proposing to

(1) set the monthly Customer Charge to collect all the customer-related costs;

(2) shorten the summer season from six months (May through October) to four months (June through September); and

(3) increase the price differential between summer and non-summer Energy Charges to \$0.03 from the current \$0.025 differential.

For the TOD Rate, EPE is proposing to:

(1) set the monthly Customer Charge equal to the Standard Service Rate monthly Customer Charge; and

(2) set the non-summer Energy Charge equal to the Standard Service Rate non-summer Energy Charge.

7. Schedule No. 24 – General Service

Q. PLEASE DESCRIBE THE EXISTING SCHEDULE NO. 24 - GENERAL SERVICE RATE.

A. This rate schedule is applicable to customers with peak metered demand exceeding 15 kW and up to 600 kW. The rate schedule includes two monthly rate options: a Standard Service Monthly Rate and an Alternate TOU Monthly Rate. The Standard Service Monthly Rate is closed to new service applications with projected demand equal to or greater than 400 kW. A clause is included that offers bill protection to customers that elect to take service under the TOU Monthly Rate for an initial twelve-month period under that rate option. An additional clause offers new customers that are required to take service under the TOU Monthly Rate the ability to take service under the Standard Service Monthly Rate after an initial twelve-month period under the TOU Monthly Rate.

Other provisions currently included under Schedule No. 24 is a Thermal Energy Storage Rider and an Off-Peak Water Heating Rider, both of which are closed to new service applications; a meter voltage adjustment applicable for certain customers; a power factor adjustment, which is applicable under certain circumstances; and a determination of billing demand with a 60% demand ratchet. It also includes reference to other applicable riders as well as terms and conditions that apply to service under this schedule.

Q. PLEASE DESCRIBE THE EXISTING STRUCTURE OF RATES OFFERED UNDER SCHEDULE NO. 24.

A. The Standard Service Rate structure consists of a monthly Customer Charge, seasonal Demand Charges, and a load factor-blocked Energy Charge (differentiated by primary and secondary service voltage). The three-step energy blocks are a function of the customer's energy use per kW of demand, with declining Energy Charges applying with progressively higher load factors (otherwise known as an "hours use of demand" rate structure). The summer Demand and Energy Charges apply in the six summer months of May through October.

The Alternate TOU Monthly Rate consists of a monthly Customer Charge and Energy Charges that apply based on the month, day, and hour that usage occurs. The On-Peak Period Energy Charge applies from noon to 6:00 P.M., weekdays during the summer season, and the Off-Peak Period Energy Charge applies during all other hours of the year.

Q. WHAT SIGNIFICANT LANGUAGE CHANGES ARE PROPOSED FOR SCHEDULE NO. 24?

A. EPE proposes to shift customers to TOD rates by requiring new service applications with projected maximum demands equal to or greater than 200 kW to take service under the TOD Rate for at least the initial twelve-month period. Moreover, a clause is added to ensure that for DG customers who qualify for and use net energy metering, the net metering provision is applied by TOD period.

Furthermore, EPE is proposing to formalize a policy on the applicability of the power factor adjustment only to maximum demands of 250 kW and above and to open the Thermal Energy Storage ("TES") Rider provision to new service applications.

Lastly, EPE is proposing to include transmission voltage pricing to both the Standard Service and TOD Rate options and to add a rate option described as Experimental off-peak rate.

Q. WHY IS EPE PROPOSING MANDATORY TOD ENERGY CHARGES FOR NEW CUSTOMERS TAKING SERVICE UNDER THE GENERAL SERVICE RATE CLASS?

A. By closing the Standard Service Rate option to new service applications with an expected maximum demand exceeding 200 kW, the Company is effectively proposing mandatory TOD Energy Charges for new customers. As discussed earlier, TOD rates better reflect the costs of providing service and provides an effective price signal to encourage customers to reduce consumption during EPE's peak hours. If the results of this mandatory rate are too burdensome to the new customer, to mitigate this, the rate schedule includes a clause that allows that customer to opt out of the TOD Rate after twelve consecutive months on that rate.

Q. SINCE MAKING THE TOD ENERGY CHARGE MANDATORY FOR CUSTOMERS WITH MAXIMUM DEMANDS EXCEEDING 400 KW, HOW MANY CUSTOMERS HAVE REQUESTED TO OPT OUT OF THE TOD RATE?

A. Two out of 76 customers that were subject to the mandatory TOD Rate have opted out since the implementation of the currently effective Schedule No. 24.

Q. PLEASE EXPLAIN EPE'S POWER FACTOR ADJUSTMENT POLICY.

A. EPE currently has in place a policy that subjects Schedule No. 24 customers to a power factor adjustment if their historical demands have exceeded 250 kW. The Company occasionally reviews customer demand profiles to determine if any customer should be subject to a power factor adjustment and notifies the customer that they are now subject to the power factor adjustment. The power factor adjustment begins to show up on a customer's bill as a separately identified item 90 days after the notice is sent to the customer.

EPE is proposing to formalize this policy on the applicability of the power factor adjustment. The language adding the power factor adjustment to Schedule No. 24 simply codifies the 250kW threshold in the tariff for an activity that is already in practice.

Q. WHY HAS EPE DECIDED TO RE-OPEN THE TES PROVISION?

A. The TES provision provides an incentive for a customer with TES systems to operate such systems during off-peak period hours. The incentive is that billing demand for this separately metered load is that which is measured during the on-peak hours; noon through 6:00 PM. Opening this provision contributes toward EPE's goal to reduce contributions to system peak demand.

Q. PLEASE EXPLAIN THE RATIONALE FOR EPE'S PROPOSAL TO ADD THE EXPERIMENTAL OFF-PEAK RATE TO SCHEDULE NO. 24.

A. Like the TES provision, the Experimental Off-Peak Rate provides an incentive for a customer to operate during off-peak hours. EPE currently offers the Experiment Off-Peak Rate as an option under Schedule No. 25 – Large Power Service. In this rate case, EPE proposes to offer a similar experimental rate option to its Schedule No. 24 customers.

Q. WHAT RATE CHANGES DOES EPE PROPOSE FOR SCHEDULE NO. 24 RATES AND RATE STRUCTURES?

A. For the Standard Service Rate, EPE is proposing to:

(1) set the monthly Customer Charge to collect all the customer-related costs;
(2) shorten the summer season from six months (May through October) to four months (June through September); and
(3) increase the price differential between summer and non-summer Demand and Energy Charges.

For the TOD Rate, EPE is proposing to:

(1) set the monthly Customer Charge equal to the Standard Service Rate monthly Customer Charge;
(2) set the Demand Charges equal to the Standard Service Rate Demand Charges; and
(3) to the extent possible, increase the price differential between On-Peak Period and Off-Peak Period summer Energy Charges.

Q. WHAT IS EPE'S RATIONALE FOR SETTING EQUALLY THE DEMAND CHARGES OF THE STANDARD AND TOD RATE OPTIONS?

A. The intent of setting the demand charges equally among both options is to incentivize customers to switch from the Standard Service to the TOD Rate option. EPE believes the disparity of the current demand charges of these options has been an impediment to customers that may benefit from the TOD Rate.

8. Schedule No. 25 – Large Power Service

Q. PLEASE DESCRIBE THE EXISTING SCHEDULE NO. 25 – LARGE POWER SERVICE RATE.

A. This rate schedule is applicable to most of EPE's largest commercial and industrial customers with peak demand exceeding 600 kW and for whom no other rate schedule applies. The rate schedule contains a single monthly time varying rate option that is differentiated by transmission, primary, and secondary voltage service.

Provisions currently included under Schedule No. 25 are a TES Rider, which is closed to new service applications; a meter voltage adjustment applicable for certain customers; a power factor adjustment, which is applicable under certain circumstances; and a determination of billing demand with a 75% demand ratchet. It also includes reference to other applicable riders as well as terms and conditions that apply to service under this schedule.

Schedule No. 25 also includes a Migration Rate Limiter Rider, which expired at the end of 2019, and an Experimental Off-Peak Period Demand Rate, which is applicable to certain qualifying customers. The Migration Rate Limiter was applicable only to accounts billed under Schedule No. 43 – University Service Rate prior to the effective date of EPE's existing rate schedules. The currently effective Experimental Off-Peak Period Demand Rate is applicable to customers whose average load factor does not exceed 30%.

Q. PLEASE DESCRIBE THE EXISTING RATE STRUCTURE OF SCHEDULE NO. 25.

A. The rate structure consists of a monthly Customer Charge, a seasonal Demand Charge, and a TOD Energy Charge. The summer Demand Charge applies in the four summer months of June through September. The on-peak period is defined as noon through 6:00 P.M., Monday through Friday. The off-peak period is comprised of all other hours.

Q. WHAT SIGNIFICANT LANGUAGE CHANGES ARE PROPOSED FOR SCHEDULE NO. 25?

A. EPE is proposing to open the TES Rider provision to new service applications and to delete the Migration Rate Limiter Rider provision, which expired in 2019. Further, a clause is added to ensure that for DG customers who qualify for and use net energy metering, the net metering provision is applied by TOD period.

Q. PLEASE DESCRIBE THE EXPERIMENTAL OFF-PEAK RATE.

A. The Experimental Off-Peak Demand Rate was originally proposed in Docket No. 40641[21] as an experimental tariff available to customers who qualify under Schedule No. 25 and who have a low load factor—defined as a twelve-month average load factor of less than 30%. The rate structure has the same on-peak period and off-peak period energy charges as those offered under the standard Schedule No. 25 rates. However, rather than a single Demand Charge that applies to maximum metered demand, the Experimental Off-Peak Rate has both a maximum Demand Charge and an On-Peak Period Demand Charge. The On-Peak Period Demand Charge is applied to 100% of the peak metered demand during the on-peak period for the billing cycle or during the last 11 months, while the maximum Demand Charge is set at a lower rate per kW than the standard Schedule No. 25 Demand Charge. The rate is designed to provide a financial incentive to encourage maximum demand use during the off-peak period rather than the on-peak period. Customers that can do this will both lower their own electric bills and assist in lowering EPE's summer peak demand, which benefits all customers by reducing the demand that EPE must meet through generation.

When the Experimental Off-Peak Rate was originally proposed in 2012, three qualifying customers signed up for service. Since then, two of the qualifying customers have shut down operations. The remaining customer has continued to take service under this rider, benefiting from the financial incentive that it provides. EPE believes that the rate structure may offer an opportunity in the future for similarly situated customers.

Q. WHAT CHANGES ARE PROPOSED FOR THE EXPERIMENTAL OFF-PEAK RATE?

A. No structural changes to the Experimental Off-Peak Rate are proposed.

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[21] *Petition of El Paso Electric Company for Approval of Rate Schedule No. 25a – Large Power Service, Experimental Off-Peak Rate*, Docket No. 40641, Notice of Approval (Sept. 28, 2012).

Q. WHAT RATE CHANGES DOES EPE PROPOSE FOR SCHEDULE NO. 25?

A. EPE is proposing to:

(1) increase the monthly Customer Charge to collect all the customer-related costs;

(2) increase the price differential between summer and non-summer Demand Charges; and

(3) to the extent possible, increase the price differential between On-Peak Period and Off-Peak Period summer Energy Charges.

9. Schedule No. 26 – Petroleum Refinery Service

Q. PLEASE DESCRIBE THE EXISTING SCHEDULE NO. 26 – PETROLEUM REFINERY SERVICE RATE.

A. Schedule No. 26 is applicable to customers operating petroleum refining facilities with peak demand exceeding 3,000 kW. The rate schedule consists of a single rate option and includes provisions for determination of billing demand, a power factor adjustment, and a charge for facilities constructed by the Company that are not reflected in the rates of the schedule. The determination of billing demand includes a 65% demand ratchet. The rate schedule also includes provisions that refer to other applicable riders as well as terms and conditions that apply to service under this schedule.

Q. PLEASE DESCRIBE THE EXISTING RATE STRUCTURE OF SCHEDULE NO. 26.

A. The rate structure consists of a monthly Customer Charge, a seasonal Demand Charge, and a uniform Energy Charge. The summer Demand Charge applies in the four summer months of June through September.

Q. WHAT SIGNIFICANT LANGUAGE CHANGES ARE PROPOSED FOR SCHEDULE NO. 26?

A. No significant language changes are proposed for this rate schedule.

Q. WHAT RATE CHANGES DOES EPE PROPOSE FOR THE SCHEDULE NO. 26 RATES AND RATE STRUCTURES

A. EPE is proposing to set the monthly Customer Charge to fully collect all the customer-related costs through that charge, and to the extent possible, increase the price differential between summer and non-summer Demand Charges.

Q. HOW ARE THE SCHEDULE NO. 26 DEMAND AND ENERGY CHARGES CALCULATED?

A. The proposed Demand Charge for Schedule No. 26 is set to reflect the underlying demand-related costs of the Petroleum Refining rate class more closely. The proposed Demand Charge also reflects a seasonal price differential to recognize the higher loads experienced on EPE's system in the summer months. The summer Demand Charge includes 25% of EPE's incremental capacity cost. The Energy Charge is set to recover all costs not recovered through the other rate components.

10. Schedule No. 30 – Electric Furnace Rate

Q. PLEASE DESCRIBE THE EXISTING SCHEDULE NO. 30 – ELECTRIC FURNACE SERVICE RATE.

A. Schedule No. 30 is closed to new service applications and is applicable to existing customers that receive service for electric furnaces for metal melting, with individual furnace or furnaces having nameplate ratings of at least 5,000 kW. The rate schedule consists of a single rate option and includes provisions for determination of billing demand, a power factor adjustment, and an interconnection charge. The determination of billing demand includes a 65% demand ratchet. The rate schedule also includes provisions that refer to other applicable riders as well as terms and conditions that apply to service under this schedule. Additionally, the rate schedule includes an Experimental Off-Peak Demand Rate.

Q. PLEASE DESCRIBE THE EXISTING RATE STRUCTURE OF SCHEDULE NO. 30.

A. The rate structure consists of a monthly Customer Charge, a seasonal Demand Charge, and a TOD Energy Charge. The summer Demand Charge applies in the four summer months of June through September. The on-peak period is defined as noon through 6:00 P.M., Monday through Friday. The off-peak period is comprised of all other hours.

Q. IS EPE INTENDING TO ELIMINATE SCHEDULE NO. 30 IN THIS BASE-RATE PROCEEDING?

A. No. One of the regulatory commitments in Docket No. 49849, the docket that effectuated IIF US Holding 2 LP's acquisition of EPE, requires EPE to not eliminate Schedule No. 30 in its next base-rate case,[22] which is this proceeding.

Q. WHAT SIGNIFICANT LANGUAGE CHANGES ARE PROPOSED FOR SCHEDULE NO. 30?

A. EPE proposes to eliminate the Experimental Off-Peak Demand Rate from the rate schedule.

Q. WHY IS THE COMPANY PROPOSING TO ELIMINATE THE EXPERIMENTAL OFF-PEAK DEMAND RATE OPTION?

A. Because customers qualifying for Schedule No. 30 are not eligible for Schedule No. 25 – Large Power Service, the off-peak period demand option in that schedule is not available to these customers. In its last rate case, EPE proposed to offer a similar rate structure as an option under Schedule No. 30 to the sole customer under that schedule to evaluate whether they may benefit based on operational changes in their consumption profile. Since the implementation of the currently effective Schedule No. 30, no customer has taken service under this rate option. Therefore, this experimental rate option is proposed for elimination.

Q. WHAT RATE CHANGES DOES EPE PROPOSE FOR THE SCHEDULE NO. 30 RATES AND RATE STRUCTURES?

A. EPE is proposing to set the monthly Customer Charge to fully collect all the customer-related costs through that charge. The Demand Charge is set to reflect the underlying demand-related costs of this rate class. The summer Demand Charge reflects a seasonal price differential to recognize the higher loads experienced on EPE's system in the summer months. The summer Demand Charge includes 25% of EPE's incremental capacity cost

[22] *Joint Report and Application of El Paso Electric Company, Sun Jupiter Holdings LLC, and IIF US Holding 2 LP for Regulatory Approvals Under PURA §§ 14.101, 39.262, and 39.915*, Docket No. 49849, Final Order at Finding of Fact No. 58(g) (Jan. 28, 2020).

and the On-Peak Period Energy Charge includes the remaining amount. The Off-Peak Period Energy Charge is set to recover all costs not recovered through the other rate components.

11. Schedule No. 31 – Military Reservation Service

Q. PLEASE DESCRIBE THE EXISTING SCHEDULE NO. 31 – MILITARY RESERVATION SERVICE RATE.

A. Schedule No. 31 is applicable exclusively to the United States Department of Defense for electric service to the Fort Bliss Military Reservation ("Fort Bliss") with minimum contracted capacity of 15,000 kW. The most recent amendment to the agreement to the contract for power service between EPE and Fort Bliss lists 14 service points of delivery, with voltages of 115 kilovolts (kV) or 13.8 kV.

The rate schedule consists of a single rate option and includes provisions for determination of billing demand, a power factor adjustment, and a metering adjustment. The determination of billing demand includes a 65% demand ratchet. The rate schedule also includes provisions that refer to other applicable riders as well as terms and conditions that apply to service under this schedule.

Q. PLEASE DESCRIBE THE EXISTING RATE STRUCTURE OF SCHEDULE NO. 31.

A. The rate structure consists of a monthly Customer Charge, a seasonal Demand Charge, and a TOD Energy Charge. The summer Demand Charge applies in the four summer months of June through September. The on-peak period is defined as noon through 6:00 P.M., Monday through Friday. The off-peak period is comprised of all other hours.

Q. WHAT SIGNIFICANT LANGUAGE CHANGES ARE PROPOSED FOR SCHEDULE NO. 31?

A. No significant language changes are proposed for this rate schedule.

Q. WHAT RATE CHANGES DOES EPE PROPOSE FOR THE SCHEDULE NO. 31 RATES AND RATE STRUCTURES?

A. EPE is proposing to set the monthly Customer Charge to fully collect all the customer-related costs through that charge. The Demand Charge is set to reflect the underlying demand-related costs of this rate class. The summer Demand Charge reflects a seasonal price differential to recognize the higher loads experienced on EPE's system in the summer months. The summer Demand Charge includes 25% of the incremental capacity cost and the On-Peak Period Energy Charge includes the remaining amount. The Off-Peak Period Energy Charge is set to recover all costs not recovered through the other rate components.

12. Schedule No. 34 – Cotton Gin Service

Q. PLEASE DESCRIBE THE EXISTING SCHEDULE NO. 34 – COTTON GIN SERVICE RATE.

A. This rate schedule is available to cotton gins for power requirements solely related to the processing of cotton during the defined operating season. All other power requirements (i.e., lighting, office electric load, etc.) are served under the otherwise applicable tariffs. The "operating season" is defined as beginning September 1st of each year (or such date later that a new customer begins service) and extending for at least three months and until April 30 of the following year (eight months maximum).

The rate structure consists of a single rate option and includes provisions for determination of billing demand and that refer to other applicable riders as well as describing terms and conditions that apply to service under this schedule.

Q. PLEASE DESCRIBE THE EXISTING RATE STRUCTURE OF SCHEDULE NO. 34.

A. The rate structure consists of an annual Customer Charge, payable in three installments over the operating season, a flat Demand Charge, and a seasonal Energy Charge. These rate components are applicable during the operating season. During the non-operating season, cotton gin customers are billed under the rates and provisions of Schedule No. 02 or Schedule No. 24, depending on which schedule the customer otherwise qualifies for.

Q. WHAT SIGNIFICANT LANGUAGE CHANGES ARE PROPOSED FOR SCHEDULE NO. 34?

A. No significant language changes are proposed for this rate schedule.

Q. WHAT RATE CHANGES DOES EPE PROPOSE FOR THE SCHEDULE NO. 34 RATES AND RATE STRUCTURES

A. EPE is proposing to

(1) increase the monthly Customer Charge to fully collect all the customer-related costs;

(2) shorten the summer season from six months (May through October) to four months (June through September);

(3) set the Demand Charge to reflect only the distribution-related cost, at full cost; and

(4) increase the price differential between summer and non-summer Energy Charges to $0.03 from the current $0.02 differential.

13. Schedule No. 38 – Interruptible Power Service

Q. PLEASE DESCRIBE THE EXISTING SCHEDULE NO. 38 – NOTICED INTERRUPTIBLE POWER SERVICE.

A. Schedule No. 38 is closed to new service applications. Noticed Interruptible Service is available to customers with total connected capacity requirements of at least 2,500 kW. The minimum level of firm demand required from qualifying customers is 600 kW. This schedule is available only in conjunction with firm service under other applicable rate schedules. Interruptible customers effectively provide a capacity resource equal to the difference between their contracted firm service level and their full load requirement. Within 30 minutes of a notice by EPE to interrupt, the customer is required to reduce their demand to their firm service level, subject to penalties provided in the rate schedule.

The rate schedule contains a single rate option (differentiated by transmission, primary, and secondary service voltage) applicable to the interruptible portion of the customer's load. The remaining portion, the "firm service" load, is billed under the otherwise applicable retail rate determined based on the customers total load requirements.

Other provisions currently included under Schedule No. 38 are a power factor adjustment, which is applicable under certain circumstances; reference to other applicable riders; as well as terms and conditions that apply to service under this schedule.

Special provisions in the rate schedule discuss determination of billing demand and energy, contracting for service, scheduling procedures, general conditions, and non-compliance.

Q. HOW MANY CUSTOMERS DOES EPE SERVE UNDER SCHEDULE NO. 38 AND HOW MUCH CAPACITY DO THEY PROVIDE TO EPE?

A. EPE has nine customers served under Schedule No. 38. Five of those customers take service at transmission voltage and the remaining four customers take service at primary voltage. These customers provide approximately 47 megawatts ("MW") of interruptible capacity.

Q. PLEASE DESCRIBE THE EXISTING RATE STRUCTURE OF SCHEDULE NO. 38.

A. The rate structure consists of a Demand Charge and an Energy Charge, both differentiated by transmission, primary, and secondary voltage service.

Q. WHAT SIGNIFICANT LANGUAGE CHANGES ARE PROPOSED TO SCHEDULE NO. 38?

A. EPE is proposing to increase the interruptible capacity to 75 MW, from the current 47 MW, by opening the rate schedule to new customers until such load level is achieved. The total connected capacity required is also reduced to 1,000 kW, from the current 2,500 kW.

Q. HOW ARE THE SCHEDULE NO. 38 DEMAND AND ENERGY CHARGES CALCULATED?

A. The Schedule No. 38 Demand and Energy Charges were designed based on demand and energy costs allocated to the Schedule No. 25 Large Power Service rate class. The Demand Charge is calculated by reducing the Schedule No. 25 voltage-differentiated demand-related costs to account for avoided incremental capacity costs. The Energy Charge is set equal to the Schedule No. 25 Off-Peak Period Energy Charge.

EPE proposes to continue to move existing interruptible demand charges towards full cost level. Therefore, a rate moderation adjustment is made that provides a credit that is higher than EPE's incremental capacity cost. This rate moderation adjustment has been used in designing interruptible service rates by EPE in other recently filed rate cases in both Texas and New Mexico.

Q. WHAT IS THE IMPACT ON EXISTING NOTICED INTERRUPTIBLE CUSTOMERS OF THE CHANGES EPE IS PROPOSING?

A. The combination of the increase in the Schedule No. 38 Demand Charge and decrease in the Energy Charge results in an overall base-rate revenue impact to non-firm service equivalent to EPE system average increase proposed in this rate case. The net impact of the changes in interruptible rates is a function of the customer's firm and non-firm service level and the proposed changes in the rate schedule applicable to the customer's firm service.

Q. DOES EPE EXPECT THAT THE PROPOSED CHANGES TO THE SCHEDULE NO. 38 RATES WILL RESULT IN CUSTOMERS DECIDING TO LEAVE NOTICED INTERRUPTIBLE SERVICE?

A. No. While the percentage increase for the class of interruptible customers as a whole is at the system average increase, the average rate paid by these customers is still lower than what they would pay, on average, for full firm service. The Demand Charge provided in this schedule is based on the value of capacity on EPE's system, which ensures that other ratepayers are not significantly disadvantaged by provision of capacity by interruptible customers versus purchases by EPE. Thus, the rates are fair to both interruptible customers and the other customers who pay for firm service and benefit from the availability of the capacity resource provided.

Q. WHY IS EPE PROPOSING TO REOPEN SCHEDULE NO. 38 TO NEW CUSTOMERS AND TO REDUCE THE TOTAL CONNECTED CAPACITY REQUIREMENT OF THAT SCHEDULE?

A. As EPE witness Schichtl discusses in his Direct Testimony, the Company is proposing to reopen this rate schedule to additional customers as a means of securing additional resources for purposes of meeting the demands of EPE's peak load until after the new resources he also discusses in his testimony begin commercial operation.

The intent of reducing the total connected capacity requirement is to attract new customers to the rate schedule.

14. Schedule No. 41 – City and County Service

Q. PLEASE DESCRIBE THE EXISTING SCHEDULE NO. 41 – CITY AND COUNTY SERVICE RATE.

A. Schedule No. 41 is closed to new service applications as of July 30, 2010. This rate schedule is applicable to public schools and for municipal and county service. The rate schedule includes two monthly rate options: a Standard Service Monthly Rate and an Alternate TOU Monthly Rate. A clause offers customers that elect to take service under the TOU Monthly Rate the ability to revert to the Standard Service Monthly Rate after an initial twelve-month period under the TOU Monthly Rate.

Other provisions currently included under Schedule No. 41 is a TES Rider, which is closed to new service applications, Non-Metered Service for instances when metering of energy is impractical due to very low monthly usage, and a meter voltage adjustment applicable for certain customers. It also includes reference to other applicable riders, as well as terms and conditions that apply to service under this schedule.

Q. PLEASE DESCRIBE THE EXISTING SCHEDULE NO. 41 – CITY AND COUNTY SERVICE RATE.

A. The Standard Service Rate structure consists of a monthly Customer Charge, seasonal Demand Charges, and declining two-block Energy Charges (differentiated by primary and secondary service voltage). The Demand Charges apply to billed kW that is more than 15 kW. Energy charges are applicable in a declining block structure, with energy exceeding 3,000 kWh charged at a substantially lower rate than the initial block. The summer Demand and Energy charges apply in the six summer months of May through October.

The Alternate TOU Monthly Rate consists of a monthly Customer Charge and Energy Charges that apply based on the month, day, and hour that usage occurs. The On-Peak Period Energy Charge applies from noon to 6:00 P.M., weekdays during the summer season, and the Off-Peak Period Energy Charge applies during all other hours of the year.

Q. WHAT SIGNIFICANT LANGUAGE CHANGES ARE PROPOSED FOR SCHEDULE NO. 41?

A. EPE proposes to add a clause to ensure that for DG customers who qualify for and use net energy metering, the net metering provision is applied by TOD period. To incentivize adoption of the TOD Rate option, EPE proposes to also include a clause that offers bill protection for an initial twelve-month period to all current customers that elect to take service under the TOD Rate. Like other rate schedules that larger customers are billed under, EPE is proposing to add a power factor adjustment provision to Schedule No. 41 as well. Lastly, the TES Rider provision is opened to new service applications.

Q. WHAT CHANGES DOES EPE PROPOSE TO SCHEDULE NO. 41 RATES AND RATE STRUCTURES?

A. For the Standard Service Rate, EPE is proposing to

(1) set the monthly Customer Charge to collect all the customer-related costs;

(2) shorten the summer season from six months (May through October) to four months (June through September);

(3) increase the price differential between summer and non-summer Demand and Energy Charges; and

(4) eliminate the declining block Energy Charge structure and replace it with a flat Energy Charge.

For the TOD Rate, EPE is proposing to set the monthly Customer Charge, the Demand Charge, and the Non-Summer Energy Charge equal to those under the Standard Service Rate.

Q. WHY IS THE COMPANY PROPOSING TO ELIMINATE THE DECLINING BLOCK ENERGY CHARGE STRUCTURE OF SCHEDULE NO. 41?

A. Declining-block rate structures, where the per unit rate for energy decreases as customers use more energy, are legacy rate structures that are no longer generally accepted because they send price signals that may encourage consumption and discourage conservation.

15. Schedule No. CS - Community Solar Service

Q. PLEASE DESCRIBE THE EXISTING SCHEDULE NO. CS – COMMUNITY SOLAR RATE.

A. This rate schedule is available to customers without distributed generation and that take service under the retail service rate schedule listed in the Monthly Rate section of Schedule No. CS. Participating customers pay a subscription price for their capacity, which is based on the cost of the Community Solar facility, and receive a credit for the quantity of energy produced by their subscribed capacity based on their EPE generation rate, as calculated in this filing.

Provisions currently included under Schedule No. CS are a Type-Of-Service provision, which details length of subscription terms and capacity minimums and maximums; a provision that describes the determination of solar billing energy; provisions on multi-year contract rates and the early termination of the Community Solar program. It also includes other terms and conditions that apply to service under this schedule.

Q. PLEASE DESCRIBE THE EXISTING RATE STRUCTURE OF SCHEDULE NO. CS.

A. The rate structure consists of a Monthly Capacity Charge and a System Generation Credit, which is applied on a per kWh basis and varies among the listed retail service schedules.

Q. HOW DID EPE DETERMINE THE SUBSCRIPTION PRICE THAT CUSTOMERS WILL PAY?

A. The subscription price for solar capacity produced by the Community Solar facility is based on the cost to EPE of the facility including construction, operation and maintenance expenses, taxes, etc. This rate reflects the total levelized cost of the Montana Power Station solar facility over its 30-year life and will remain unchanged for the term of the customer's contract.

For details on the calculation of the current subscription price, please reference the documents filed in Docket No. 48181.[23]

[23] *Application of El Paso Electric Company to Expand Solar Generation Capacity and Change Rates for the Community Solar Pilot Program*, Docket No. 48181, Order (May 9, 2019).

Q. IS EPE PROPOSING CHANGES TO THE SUBSCRIPTION PRICE?

A. No. EPE is not proposing to modify the Community Solar subscription price in this case.

Q. IS EPE PROPOSING CHANGES TO THE GENERATION RATE?

A. Yes. As described in the Docket No. 44800[24] settlement testimony of EPE witness Schichtl, the Community Solar generation credit reflects production costs allocated to rate classes and reflected in their respective rates. EPE proposes to update the generation credit for the allocated production costs of the current filing.

Q. HOW DOES EPE RECOVER AMOUNTS PROVIDED TO SUBSCRIBERS VIA THE GENERATION CREDIT?

A. The amounts provided to subscribers as a generation credit is recovered through the base rates of each of the retail rate schedules that are listed in Schedule No. CS.

Q. IS EPE PROPOSING ANY OTHER CHANGES TO THE COMMUNITY SOLAR TARIFF?

A. Yes. EPE believes it is appropriate to refine the tariff applicability to exclude the following retail service schedules from the currently effective tariff:

- Schedule No. 09 – Governmental Traffic Signal Service;
- Schedule No. 11 – TOU Municipal Pumping Service;
- Schedule No. 15 – Electrolytic Refining Service;
- Schedule No. 22 – Irrigation Service;
- Schedule No. 26 – Petroleum Refinery Service;
- Schedule No. 30 – Electric Furnace Service;
- Schedule No. 31 – Military Reservation Service; and
- Schedule No. 34 – Cotton Gin Service.

EPE has no expectation for these types of customers to subscribe to the Community Solar program.

[24] *Application of El Paso Electric Company to Implement a Voluntary Community Solar Pilot Program in Texas*, Docket No. 44800, Order (Sept. 1, 2016).

16. Schedule No. EVC - Electric Vehicle Charging

Q. PLEASE DESCRIBE EPE'S EXISTING SCHEDULE NO. EVC - ELECTRIC VEHICLE CHARGING RATE.

A. This rate schedule is available, on a voluntary basis, to residential and commercial customers that have a separately metered facility dedicated solely for the charging of electric vehicles and only for charging activity operating at 120 volts ("V") or 240 V.

The rate schedule contains a single monthly time varying rate option. It also includes provisions that reference other applicable rider, as well as terms and conditions that apply to service under this schedule.

Q. PLEASE DESCRIBE THE EXISTING RATE STRUCTURE OF SCHEDULE NO. EVC.

A. The Schedule No. EVC rate structure consists of a monthly Customer Charge and a TOU Energy Charge. The on-peak period is defined as noon through 6:00 P.M., Monday through Friday, for the months of June through September. The off-peak period includes all other hours.

Q. WHAT SIGNIFICANT LANUAGE CHANGES ARE PROPOSED FOR SCHEDULE NO. EVC?

A. EPE is proposing to expand the availability of this schedule to accommodate charging activity operating of up to 480 V. EPE proposes to expand the monthly rate section to correspond to the retail rate schedule that, but for the taking of service under Schedule No. EVC, the consumption for electric vehicle ("EV") charging would have billed under. Therefore, the Monthly Rate section of the proposed rate schedule lists the following qualifying retail rate schedules along with the applicable rates under Schedule No. EVC:

- Schedule No. 01 – Residential Service;
- Schedule No. 02 – Small General Service;
- Schedule No. 24 – General Service;
- Schedule No. 25 – Large Power Service; and
- Schedule No. 41 – City and County Service.

Q. WHAT CHANGES DOES EPE PROPOSE FOR SCHEDULE NO. EVC RATES AND RATE STRUCTURES?

A. EPE is proposing to modify the schedule's rates and rate structure that provide both residential and commercial customers with price incentives to encourage the charging of electric vehicles during off-peak periods and dissuade customers from charging during summer on-peak periods, when EPE's generation system experiences its peak loads. Incentivizing charging during the hours of least load on EPE's system may result in downward pressure on the rates of all customers. The rates and rate structure will result in Schedule No. EVC customers contributing toward the costs of the Company's distribution system.

The proposed monthly Customer Charge will only include the costs related to meters, services drops, and meter reading, which are the most relevant incremental customer-related cost to provide this service and to avoid the duplication in the recovery of other customer-related costs paid by customers through their otherwise applicable rate schedule.[25]

The on-peak period is defined similarly to other TOD rates proposed in this case, from noon through 6:00 P.M., Monday through Friday, for the months of June through September. Furthermore, the proposed Schedule No. EVC offers a new feature not currently offered to customers, which is a "Super Off-Peak Period" rate applicable to daily consumption, from 12:00 A.M. to 8:00 A.M. The off-peak period includes all other hours.

The summer On-Peak Period Energy Price adders were determined using the same methodology employed for other TOD rate offerings, except that on-peak period charges fully reflect EPE's incremental capacity costs. This is to disincentivize EV charging at the time of the day that EPE's generation resources system typically experiences its peak demand.

Also, EPE used the corresponding retail rate schedule TOD summer off-peak period and non-summer Energy Charge as a proxy for the proposed Schedule No. EVC summer Off-Peak Period and non-summer Energy Charge of each listed retail rate since there is no reason why the summer Off-Peak Period and non-summer Energy Charges

[25] Since sales under Schedule No. EVC have not arisen to a level significant enough to establish it as a rate class, there is no cost allocation to this rate schedule. In subsequent rate cases, EPE expects to be able to more accurately allocate and assign costs to this new tariff as load and consumption information becomes available. EPE uses the costs applicable to Schedule No. 02 to derive the Schedule EVC Customer Charge for the listed Schedule Nos. 02, 24, 25, and 41.