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

REBUTTAL TESTIMONY

OF

ADRIAN HERNANDEZ

FOR

EL PASO ELECTRIC COMPANY

NOVEMBER 19, 2021

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I. Introduction and Qualifications

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Adrian Hernandez. 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 a Senior Rate Analyst.

Q. ARE YOU THE SAME ADRIAN HERNANDEZ WHO SUBMITTED DIRECT TESTIMONY?

A. Yes, I am.

II. Purpose of Rebuttal Testimony

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. The purpose of my rebuttal testimony is to present the Company's rebuttal cost of service studies (including the updated baseline calculations) and to address the issues raised by other parties in their direct testimony.

Specifically, I will summarize the results of EPE's jurisdictional cost of service ("JCOS") study and respond to the following topics related to jurisdictional cost allocation:

- Allocation of Production Plant
- DPROD12 Allocator

I will also summarize the results of EPE's rebuttal class cost of service ("CCOS") study and address the issues related to class allocation such as:

- Allocation of Production Plant
- Production Operation and Maintenance ("O&M") Expenses
- Imputed Capacity Allocation
- Allocation of Load Dispatching Expenses
- DPROD12 Allocator
- E1ENERGY and E2ENERGY Allocators
- Inclusion of Fuel Revenues and Eligible Fuel Expenses

- Administrative and General ("A&G") Accounts 920-923, and 930.2
- Allocation of A&G Account 930.1
- Allocation of 69 kV Costs to 115 kV Customers
- Distribution Cost Allocation
- Uncollectible expense
- Contributions and Donations
- Staff's Cost of Service and Baseline Calculations

Q. WILL THERE BE AN UPDATE TO THE BASELINE CALCULATIONS YOU ORIGINALLY PROPOSED IN YOUR DIRECT TESTIMONY?

A. Yes. Using EPE's rebuttal cost of service, I have updated the baseline calculations for the Distribution Cost Recovery Factor ("DCRF"), Transmission Cost Recovery Factor ("TCRF"), and Generation Cost Recovery Rider ("GCRR").

Q. ARE YOU SPONSORING ANY EXHIBITS IN YOUR REBUTTAL TESTIMONY?

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

- Exhibit AH-1R: Revised Schedules A-1 and B-1.1
- Exhibit AH-2R: Rebuttal Jurisdictional Cost of Service Study Summary
- Exhibit AH-3R: Rebuttal Class Cost of Service Study Summary
- Exhibit AH-4R: Rebuttal Distribution Cost Recovery Factor Baseline
- Exhibit AH-5R: Rebuttal Transmission Cost Recovery Factor Baseline
- Exhibit AH-6R: Rebuttal Generation Cost Recovery Rider Baselines

III. Rebuttal Cost of Service Studies

Q. HAS EPE MADE ANY CHANGES TO ITS COST OF SERVICE STUDY.

A. Yes. As this proceeding has progressed and having reviewed the intervenor and Staff testimonies, EPE has identified several corrections and adjustments that should be made to its original request. EPE has updated the cost of service based on the changes that other witnesses have made in their rebuttal testimony. EPE witness Jennifer Borden summarizes these changes on a total company basis in her rebuttal testimony. Exhibit AH-1R presents a revised version of Schedules A-1, Cost of Service – Texas Retail, and B-1.1, Rate Base

– Texas Retail that also reflects EPE's rebuttal updates compared to EPE's original filing. Exhibit AH-2R summarizes the rebuttal JCOS study and Exhibit AH-3R summarizes the rebuttal CCOS study.

Q. BASED ON THE REBUTTAL JURISDICTIONAL COST OF SERVICE, WHAT IS THE UPDATED REVENUE REQUIREMENT THAT EPE IS REQUESTING?

A. With reference to Table AH-1R below and Exhibit AH-1R, EPE has calculated a total revenue requirement for the Texas jurisdiction of $746.9 million. After adjusting that amount for fuel revenues and other operating revenues, the remaining $574.3 million base rate revenue requirement exceeds current annualized retail base revenue by $35.7 million (or 6.6 percent). The following table shows the results of the Texas jurisdictional cost of service:

Table AH-1R

Line	Description	Amount
1	Total Rate Base	$2,031,056,418
2	Weighted Average Cost of Capital ("WACC")	7.985%
3	Return on Rate Base	$162,184,729
4	Fuel and Purchased Power	$147,226,500
5	Operation and Maintenance (O&M)	$242,446,124
6	Depreciation & Amortization	$99,002,648
7	Decommissioning and Accretion	$111,836
8	Regulatory Debits and Credits	$790,344
9	Taxes Other Than Income	$68,305,057
10	Federal Income Taxes	$23,410,067
11	State Income Taxes	$3,513,001
12	Total Cost of Service	$746,990,306
13	Less: Other Operating Revenues	($26,921,992)
14	Less: Fuel Revenues and Sales for Resale	($145,796,929)
15	Base Rate Revenue Requirement	$574,271,385
16	Less: As Adjusted Base Revenues	($538,577,847)
17	Base Rate Revenue Deficiency	$35,693,538
18	Percent Increase	6.6%

Exhibit AH-1R presents an overall summary of the Rebuttal JCOS study.

Q. PLEASE SUMMARIZE THE OVERALL RESULTS OF THE TEXAS REBUTTAL CLASS COST-OF-SERVICE STUDY.

A. The summarized results of the CCOS study are presented in Exhibit AH-3R. In addition, Table AH-2R below lists the results of the non-fuel cost assignment to each proposed rate class from the CCOS (not including non-firm revenues). The values shown are at equalized rate of return (full cost of service) and do not represent the proposed distribution of revenues. The proposed allocation of updated revenue requirements among rate classes is discussed and presented in the rebuttal testimony of EPE witness Carrasco.

Table AH-2R

Rate	Description	As Filed Firm Base Revenue Deficiency @ Equalized Rate of Return*	Percent Increase Required	Rebuttal Firm Base Revenue Deficiency @ Equalized Rate of Return*	Percent Increase Required
01	Residential Service	$52,607,044	19.22%	$51,687,454	18.89%
02	Small General Service	(3,181,502)	-9.55%	(3,524,326)	-10.58%
07	Outdoor Recreational Lighting	153,617	33.18%	145,438	31.41%
08	Government Street Lighting	(967,831)	-23.92%	(1,011,667)	-25.00%
09	Traffic Signals	3,416	3.59%	2,092	2.20%
11 TOU	Municipal Pumping TOU	95,157	0.94%	(40,327)	-0.40%
15	Electrolytic Refining Service	407,243	22.25%	379,961	20.76%
WH	Water Heating Service	335,205	70.63%	323,282	68.12%
22	Irrigation Service	135,518	32.01%	128,882	30.44%
24	General Service	(10,767,792)	-8.61%	(12,290,200)	-9.83%
25	Large Power Service	1,321,031	3.67%	338,161	0.93%
26	Petroleum Refinery Service	1,976,474	18.03%	1,811,511	16.52%
28	Area Lighting Service	(289,540)	-9.87%	(314,706)	-10.73%
30	Electric Furnace Rate	314,558	26.39%	296,066	24.84%
31	Military Reservation Service	1,766,040	13.57%	439,695	3.06%
34	Cotton Gin Service	45,212	34.00%	42,913	32.27%
41	City and County Service	(2,136,072)	-11.17%	(2,720,691)	-14.22%
Total*		$41,817,778	7.85%	$35,693,538	6.68%

*The base revenue deficiency amounts above do not include non-firm revenues.

IV. Jurisdictional Cost of Service Issues

a. Allocation of Production Plant

Q. WHAT IS EPE'S PROPOSED JURISDICTIONAL ALLOCATION OF PRODUCTION PLANT AND RELATED COSTS?

A. As discussed in my direct testimony, EPE proposes to use a Four Coincident Peak – Average & Excess ("4CP-A&E") allocator to allocate demand-related production costs of non-peaking generation facilities (D1PROD) and a Four Coincident Peak ("4CP") allocator to allocate demand-related costs of peaking generation facilities (D2PROD) in its cost of service.[1] The reason for this is to reflect EPE's actual mix of generation facilities and how they operate.

Q. WERE THERE ANY PARTIES WHO DISAGREED WITH EPE'S JURISDICTIONAL ALLOCATION OF PRODUCTION PLANT?

A. Yes. Mr. Evan D. Evans on behalf of the Office of Public Utility Counsel ("OPUC") disagreed with EPE proposal to divide its production plant into non-peaking and peaking plant for cost allocation purposes.

Others also argued against EPE on this issue as it relates to rate class allocation (discussed in the next section). One possible reason for their silence on this issue within the JCOS might be because EPE's approach to use a 4CP allocator in the JCOS actually results in a lower allocation to the Texas jurisdiction.

Q. WHAT WERE THE REASONS CITED BY MR. EVANS FOR HIS OPPOSITION TO EPE'S PROPOSED ALLOCATION OF PEAKING AND NON-PEAKING PRODUCTION PLANT?

A. Mr. Evans points out that this is the first rate case in which EPE split its production plant between peaking and non-peaking facilities and that EPE has previously allocated all demand-related production costs among its jurisdictions based on the 4CP-A&E method in prior rate cases.

Mr. Evans then argues that the historical data does not support EPE's proposal and that it contradicts the statements I made in my direct testimony. Mr. Evans analyzed EPE's natural gas-fired plants from 2017 to 2020 and determined that the six units that EPE identified as peaking units generate a substantial amount of the energy during all the months of the year and not just during the peak hours of the four summer months.

Q. WHAT IS YOUR RESPONSE TO MR. EVANS?

A. Mr. Evans is correct to point out that this is the first time that EPE has proposed this allocation approach to distinguish between peaking and non-peaking production plant in Texas. However, this is not the first time that EPE has proposed this approach in a rate

[1] The 4CP-A&E and 4CP allocators are developed by EPE witness George Novela.

case. EPE made the same proposal in its most recent New Mexico rate case where the issue was examined and ultimately approved by the New Mexico Public Regulation Commission.

Mr. Evans also makes a reasonable argument about the six peaking units' historical generation. However, that is not an indicator of what EPE is expecting going forward. The fact that EPE has relied on its peaking generation facilities throughout the year these last five years may have a lot more to do with the historically low cost of natural gas than anything else. It certainly does not change the nature of those facilities and how they are designed to be ramped up in moments of peak. As EPE adds more renewable generation as a result of cost and regulatory requirements, EPE expects that these units will be used less during off-peak periods.

Q. DO YOU AGREE WITH MR. EVANS RECOMMENDATION?

A. No. EPE's proposal to allocate peaking generation facilities with a 4CP allocator is forward looking. EPE wants to modernize its allocation methodology to recognize how EPE's generation resource mix has changed (and will change) over time, especially the peaking generation resources which are designed to meet customer load expectations and renewable generation fluctuations more efficiently. EPE expects to become more dependent on renewable resources in the future.

b. Error with 12CP Production Allocator (DPROD12)

Q. PLEASE DESCRIBE THE ERROR THAT OPUC WITNESS EVANS IDENTIFIED WITH THE DPROD12 ALLOCATOR.

A. OPUC witness Evans asserts that there is an error with the DPROD12 allocator used to allocate Account 556 generation load dispatching expense in the cost of service. He discovered that EPE's DPROD12 allocator is actually a 12CP-A&E allocator, not a 12CP.

Q. HOW DO YOU RESPOND TO MR. EVANS' CLAIM THAT THERE IS AN ERROR WITH THE DPROD12 ALLOCATOR?

A. There is no error in the calculation of the DPROD12 allocator or the application of the allocator in the cost of service; however, Mr. Evans is right to point out that the description of DPROD12 in my direct testimony does not make it clear that it is a 12CP-A&E allocator. EPE will make sure to correctly identify and describe DPROD12 as a 12CP-A&E allocator going forward. The only account that is allocated with the mislabeled DPROD12 allocator is Account 556 Load Dispatching expense and using 12CP-A&E to allocate that account is reasonable.

V. Class Cost of Service Issues

a. Allocation of Production Demand Costs

Q. PLEASE SUMMARIZE THE PARTIES' POSITIONS ON EPE'S PROPOSED ALLOCATION OF DEMAND-RELATED PRODUCTION COSTS IN THE CLASS COST OF SERVICE.

A. The witnesses who took a position on this issue are listed below:

- Mr. Jeffry Pollock on behalf of Freeport-McMoRan, Inc. ("FMI") argues that EPE's proposal is a change from prior CCOS studies and that it is also contrary to past Commission practice. He recommends that since the 4CP A&E method already recognizes that EPE serves load from a mix of different types of generating units, it should be used to allocate all production plant.
- Mr. Kevin C. Higgins on behalf of Texas Industrial Energy Consumers ("TIEC") argues that it is neither necessary nor desirable to allocate individual generation facilities piecemeal on a different basis because the 4CP A&E method is a robust cost allocation method that can properly be used to allocate a utility's entire generation fleet.
- Mr. Adrian Narvaez on behalf of the Rate Regulation Division ("STAFF") of the Public Utility Commission of Texas ("PUCT") disagrees with EPE's proposed methodology because it conflicts with well-established Commission precedent and argues that it is unwarranted because the 4CP A&E allocation factor already appropriately acknowledges 4CP peak demand.
- OPUC witness Evans makes the same recommendation in the CCOS study that he did in the JCOS study, that EPE's production plant not be divided into peaking and non-peaking for the reasons stated in the previous section.

Q. WHAT IS YOUR RESPONSE TO THE FACT THAT EPE PREVIOUSLY USED THE 4CP-A&E METHOD TO ALLOCATE ALL GENERATION PLANT-RELATED COSTS BETWEEN ITS RATE CLASSES IN PRIOR RATE CASES?

A. There is no question that EPE's use of the 4CP-A&E allocation method for all generation resources has been suitable in the past, but there are a couple of reasons why EPE has proposed a different allocation for peaking generation facilities. The first reason is that because of EPE's use of PowerPlan's Regulatory Management Suite ("RMS"), distinctions can now be made between peaking and non-peaking generation units fairly easily in EPE's cost of service. The other reason is that EPE has experienced record system peaks during the summer months of June through September. If you consider that EPE expects this trend to continue along with an increased dependence on renewable generation resources, it makes sense to allocate its peaking generation facilities with a 4CP allocator.

Q. WHY IS THE 4CP-A&E METHOD NOT APPROPRIATE FOR ALL PRODUCTION DEMAND-RELATED COSTS SINCE IT ALREADY ACCOUNTS FOR 4CP DEMAND?

A. While the 4CP A&E method is still being applied to most of EPE's generation resources so that the majority of the production demand-related cost is allocated to <u>all</u> rate classes, EPE does not think it is appropriate for those rate classes whose usage occurs outside of peak hours (e.g., lighting classes) to be assigned the demand-related costs of peaking facilities that are specifically designed to be ramped up during hours of peak. EPE believes this is a healthy compromise where rate classes such as lighting classes still receive allocation of most production plant costs, but the costs associated with peaking production plants should go to those classes that are driving the system peak.

Q. WHAT IS YOUR RESPONSE TO THE ARGUMENT THAT EPE'S PROPOSAL GOES AGAINST COMMISSION PRECEDENT?

A. Just because it has been Commission practice to approve the 4CP-A&E method class allocation factors does not mean that EPE's proposal is inappropriate. EPE is still proposing to allocate most of its production plant with the 4CP-A&E method consistent with the Commission precedent. However, EPE's proposal to allocate the peaking generation facilities differently is unlike those other cases that Staff witness Narvaez referenced in his testimony.[2] EPE is not aware of another case in Texas where a utility has proposed different allocation methods for different generation types, but EPE does know of one example from California where Southern California Edison ("SCE") proposed different allocation methods for their production plant because they recognized that, with the expansion of renewable resources, generation plants are used in different manners. As a result, SCE proposed using, and the California Public Utilities Commission approved a settlement that used, different allocations for different production plants, not just one for all of its generation.[3] That distinction between generation types is what EPE is proposing in this proceeding. EPE expects that as other utilities add intermittent renewable generation, they too will propose to allocate their production plant-related costs in a similar manner.

Q. DO YOU HAVE ANYTHING ELSE TO SAY ABOUT EPE'S PROPOSED ALLOCATION OF DEMAND-RELATED PRODUCTION COSTS?

A. Yes, it should be noted again that EPE's approach to allocate peaking generation plant with a 4CP allocator was fully litigated and approved in EPE's recent New Mexico rate case. I must also point out the inconsistency of the parties who argued against this issue in the CCOS study, but were silent on the same issue in the JCOS study when it resulted in a lower allocation to Texas.

To conclude, it makes sense for EPE to modernize its allocation methodology to recognize how EPE's generation resource mix has changed over time, especially the peaking generation resources which are designed to meet customer load expectations and renewable generation fluctuations more efficiently.

[2] See page 7 of Staff witness Adrian Narvaez's direct testimony.

[3] See California Public Utilities Commission's Decision on Southern California Edison Company's Proposed Rate Designs and Related Issues, at page 13: "They sought to distinguish marginal generation capacity costs between costs related to traditional peak generation capacity and costs related to the new concept of 'flexible' generation capacity (flex capacity) that responds to steep ramps in required generation capacity."

b. Classification of Production O&M Expenses

Q. PLEASE DESCRIBE EPE'S APPROACH FOR CLASSIFYING NON-FUEL PRODUCTION O&M EXPENSES.

A. EPE's approach for classifying demand-related or energy-related production costs are based on the guidance provided in the Electric Utility Cost Allocation Manual ("NARUC Manual") published by the National Association of Regulatory Utility Commissioners ("NARUC").

Q IS THERE A SET METHOD FOR CLASSIFYING PRODUCTION O&M EXPENSES?

A. Not necessarily. While different approaches can be taken on how to classify those costs between demand and energy, the NARUC Manual's guidance has been widely accepted.

Q. EXPLAIN WHY EPE'S APPROACH TO CLASSIFICATION OF PRODUCTION NON-FUEL O&M EXPENSES IS DIFFERENT THAN IN THE PRIOR RATE CASE.

A. Since EPE's last Texas rate case, EPE decided to take a more holistic approach to its cost allocations so that there would be a consistent methodology between EPE's jurisdictions. Therefore, using the NARUC Manual as a general guide, the allocation methodology that has been proposed in the most recent rate cases is now consistent between EPE's Texas and New Mexico retail jurisdictions.

Q. DO ANY INTERVENORS QUESTION EPE'S CLASSIFICATION OF PRODUCTION NON-FUEL O&M EXPENSES?

A. Yes. FMI witness Pollock and TIEC witness Higgins contest EPE's classification and allocation approach of non-fuel production O&M expenses.

Q. PLEASE SUMMARIZE MR. POLLOCK'S RECOMMENDATIONS.

A. FMI witness Pollock recommends that the labor-related expenses in FERC Account Nos. 502 and 505 be classified to demand. He also recommends that all of the expenses in FERC account Nos. 519, 520, and 523 related to Palo Verde Nuclear Generating Station ("PVNGS") should be classified to demand, consistent with EPE's past proposals because the portions of labor and materials are not defined and, as Pollock claims, EPE has provided no support for classifying the entirety of these accounts to energy.

Q. DO YOU AGREE WITH MR. POLLOCK's RECOMMENDATIONS?

A. No. As shown in EPE's cost of service model, EPE is correctly classifying the expenses in FERC Account Nos. 502 and 505 between demand and energy as prescribed by the NARUC Manual (on the basis of labor and non-labor).

As for Mr. Pollock's recommendation regarding the PVNGS O&M accounts, EPE classified the nuclear production O&M accounts according to the NARUC Manual. On EPE's books, there is no labor in FERC account Nos. 519, 520, and 523, therefore from EPE's perspective, it should be classified as energy.

Q. PLEASE SUMMARIZE TIEC WITNESS HIGGINS' RECOMMENDATIONS.

A. TIEC witness Higgins recommends that PVNGS non-fuel generation O&M expenses be allocated using D1PROD, EPE's 4CP-A&E production demand allocator. He specifies that EPE should replace their proposed allocation of Accounts 519, 520, 523, 530, 531, and 532 from an energy to 4CP-A&E demand. Mr. Higgins' reasoning for this recommendation is that PVNGS O&M expenses are a pass-through from APS and EPE should treat such expenses as fixed costs related to EPE's capacity share instead of variable energy throughput.

Q. DO YOU AGREE WITH MR. HIGGINS' RECOMMENDATIONS?

A. No. EPE is following the NARUC Manual which clearly shows that FERC account Nos. 530, 531, and 532 should be allocated on energy. Mr. Higgins uses the term "pass-through" to make the point that the costs from APS should be considered fixed costs simply because it is passed on to EPE, but the most obvious example of a "pass-through" cost that I can think of is fuel cost (which is as variable as it gets). EPE cannot just treat all non-fuel costs from PVNGS as demand-related. Regardless of EPE's ownership percentage of PVNGS, there should still be an energy component to nuclear production O&M. Furthermore, the majority of non-fuel O&M expenses from PVNGS are still being classified as demand-related in EPE's cost of service. From EPE's perspective, the classification of nuclear O&M is reasonable. Mr. Higgins' recommendation should be rejected.

c. Imputed Capacity Allocation

Q. HOW DID EPE ALLOCATE IMPUTED CAPACITY COSTS IN THE CLASS COST OF SERVICE?

A. EPE allocates imputed capacity costs with the demand allocator, D1PROD.

Q. DO ANY INTERVENORS QUESTION EPE'S RATE CLASS ALLOCATION OF IMPUTED CAPACITY COSTS?

A. Yes. CEP witness Johnson argues that EPE did not provide an explanation for changing the class allocation of imputed capacity from an energy allocator to a demand allocator. He recommends that EPE apply either the E1ENERGY allocator or the DPROD12 allocator.

Q. DO YOU AGREE WITH MR. JOHNSON'S RECOMMENDATION?

A. No. First of all, I disagree with the argument that EPE did not provide an explanation. On page 13 (lines 12 to 13) of my direct testimony, I specifically address EPE's treatment of imputed capacity costs as a demand-related costs. In fact, EPE made the switch to use the D1PROD allocator in its last rate case (Docket No. 46831) where I agreed in rebuttal testimony with TIEC witness Higgins that imputed capacity costs should be classified as demand-related. Therefore, EPE is using the demand allocator D1PROD to allocate the imputed capacity costs. Mr. Johnson's recommendation should be rejected.

d. Allocation of Load Dispatching Costs

Q. BOTH FMI WITNESS POLLOCK AND TIEC WITNESS HIGGINS RECOMMEND THAT EPE ALLOCATE LOAD DISPATCHING COSTS USING THE 4CP-A&E ALLOCATOR (D1PROD) FOR ACCOUNT 556 AND 4CP ALLOCATOR (D2TRAN) FOR ACCOUNT 561. DO YOU AGREE?

A. No. EPE believes that 12-CP is appropriate. Specifically, EPE decided to use a 12CP-A&E production allocator (DPROD12) for Account 556-System Control and Load Dispatching and a 12CP transmission allocator (DTRAN12) for Account 561-Load Dispatching. These allocators were chosen as a result of a recommendation of OPUC witness Marcus in a prior rate case, Docket No. 44941, where it was persuasively argued that load dispatching is not simply a function of peak demand but rather a function that operates 24 hours of each day, all year, to ensure that loads meet peak demands regardless of the month, and EPE agreed. Therefore, Mr. Higgins' recommendation regarding load dispatching costs should be rejected.

e. Error with 12CP Production Allocator (DPROD12)

Q. PLEASE DESCRIBE THE ERROR THAT OPUC WITNESS EVANS IDENTIFIED WITH THE DPROD12 ALLOCATOR.

A. Similar to his argument in the JCOS study, OPUC witness Evans asserts that there is an error with the mislabeled DPROD12 allocator used to allocate Account 556 generation load dispatching expense in the class cost of service.

Q. HOW DO YOU RESPOND TO MR. EVANS' CLAIM THAT THERE IS AN ERROR WITH THE DPROD12 ALLOCATOR IN THE CCOS?

A. As described in the previous JCOS section, there is no error in calculation of the mislabeled DPROD12 allocator or the application of the allocator in the class cost of service. EPE will make sure to correctly identify and label the 12CP A&E allocator going forward.

f. E1ENERGY and E2ENERGY Allocators

Q. WHICH INTERVENORS HAVE ISSUES WITH EPE'S ENERGY ALLOCATORS?

A. FMI witness Pollock and OPUC witness Evans discuss EPE's energy allocators in their respective testimonies. Mr. Pollock has an issue with EPE's E2ENERGY allocator and Mr. Evans has an issue with EPE's E1ENERGY allocator.

Q. WHAT IS FMI'S WITNESS POLLOCK'S ISSUE WITH THE E2ENERGY ALLOCATOR AND WHAT DOES HE RECOMMEND?

A. Mr. Pollock recommends that the E1ENERGY allocator be used to allocate all costs that are classified as energy. He recommends that the Commission reject EPE's E2ENERGY allocator.

Q. WHY DOES EPE HAVE AN E2ENERGY ALLOCATOR?

A. There are certain cost items in EPE's cost of service that are truly related to fuel (such as fuel inventory) or are driven by fuel-related items (such as tax timing differences related to deferred fuel cost recovery) but are recovered in base rates as non-fuel energy costs. Since these costs are driven by fuel-related activities, the use of the E2ENERGY allocator is appropriate to allocate these costs. The E2ENERGY allocator mimics the E1FUEL allocator in that it uses all kWh (firm and non-firm) to allocate these fuel-related activities more accurately.

Q. DO YOU AGREE WITH MR. POLLOCK'S RECOMMNENDATION?

A. No. Since these costs are caused by fuel related activities, it is reasonable to allocate them on the same basis using all kWh.

Q. WHAT IS OPUC WITNESS EVANS' ISSUE WITH THE E1ENERGY ALLOCATOR AND WHAT DOES HE RECOMMEND?

A. OPUC witness Evans takes issue with the fact that EPE's E1ENERGY allocator excludes energy sales related to interruptible loads. He recommends that the energy charge for interruptible service be increased to reflect the portion of generation O&M expenses and other associated costs that would be allocated to the interruptible energy as if they were treated as a separate class. In addition, he recommends that the associated incremental interruptible revenue should be credited to firm customers and allocated based upon the ElENERGY allocator.

As an alternative, Mr. Evans recommends a different approach to simply assign the interruptible energy to the classes with interruptible customers (presumably using the E2ENERGY allocator) to protect those classes that only have firm service customers even though it would not help firm service customers in the same class as non-firm service customers.

Q. DO YOU AGREE WITH EITHER OF MR. EVANS RECOMMENDATIONS?

A. No, I do not. Mr. Evans' recommendation to increase the energy charge for interruptible service is not something that is done in the cost of service. At EPE, interruptible (non-firm) service is not considered a stand-alone rate class. Since more than one rate class can take interruptible service, it is not subject to cost of service allocations. Therefore, for proper allocation of costs, the energy allocator applied to non-fuel energy-related O&M accounts must not include energy related to interruptible service. For that reason, Mr. Evans' alternative recommendation of using the E2ENERGY allocation factor (including interruptible kWh) instead of the E1ENERGY allocation factor (excluding interruptible kWh) should also be rejected.

Q. DO YOU HAVE ANYTHING ELSE TO SAY ON EPE'S USE OF THE E1ENERGY AND E2ENERGY ALLOCATOR?

A. Yes, I do. The fact that FMI witness Pollock and OPUC witness Evans disagree on the E1ENERGY and E2ENERGY allocators is an indication that EPE's approach is reasonable. There is a middle ground where EPE can allocate production O&M costs based on firm kWh and fuel related costs on all kWh.

g. Inclusion of Fuel Revenues and Fuel Expenses

Q. WHAT IS THE ISSUE BROUGHT UP BY FMI WITNESS POLLOCK?

A. FMI witness Pollock opposes the inclusion of fuel factor revenues and eligible fuel and purchased power expenses in the class cost of service. He recommends that they be removed.

Q. DO YOU AGREE WITH MR. POLLOCK'S RECOMMENDATION?

A. No. EPE is following the instructions in the rate filing package regardless of when they were published. EPE also likes to be consistent between its cost of service levels. The fuel costs (and revenues) flow through from total company all the way down to the Demand, Energy, and Customer ("DEC") components level where in each level they net to zero. I don't see an issue with the inclusion of fuel factor revenues and eligible fuel and purchased power expenses in the class cost of service. Mr. Pollock's recommendation should be rejected.

h. Administrative and General ("A&G") Accounts 920-923, and 930.2

Q. CEP WITNESS JOHNSON RECOMMENDS THAT ADMINSTRATIVE AND GENERAL ACCOUNTS 920-923, AND 930.2 CLASSIFIED AS "GENERAL" SHOULD BE ALLOCATED ON A NET PLANT ALLOCATOR INSTEAD OF THE LABOR ALLOCATOR. HE CLAIMS THAT THE LABOR ALLOCATOR RESULTS IN A DISTORTION SINCE PALO VERDE SALARIES AND WAGES ARE NOT INCLUDED IN THE ALLOCATION. HOW DO YOU RESPOND?

A. The labor allocator is one of the most often-used allocators in cost of service studies. The Company's labor costs from production, transmission, distribution, and customer accounting are used to develop this allocator. Following the NARUC Manual's recommendation, EPE applies the LABOR allocator to all General plant accounts and applicable A&G expenses.

Mr. Johnson takes exception to the typical practice of using a labor allocator for Accounts 920-923 and 930.2. He recommends that these expenses be allocated on the basis of net plant in service. His concern is that the labor allocator understates the magnitude of the Company's production function because it does not take into account labor costs of Arizona Public Service ("APS") employees who operate PVNGS. While it is important to note that EPE does take into account payroll for its own employees who work on-site at PVNGS in the labor allocator, EPE does not (and should not) keep track of the labor of APS employees. The relationship that EPE has with APS is similar to that of a vendor who invoices EPE and in that type of situation, EPE would not record a vendor's labor as their own. Finally, the use of a net plant allocator would overstate the production function and understate other functions (especially customer O&M) making it less accurate. Once again, Mr. Johnson seems to be more concerned about the allocation results of using certain allocators rather then cost causation.

EPE believes that it is properly applying the correct allocator to Accounts 920-923 and 930.2, namely a labor allocator, which is properly calculated and consistent with NARUC's recommendation. Additionally, EPE believes it is not reasonable to "cherrypick" the use of the labor allocator for certain accounts and to leave all the other accounts that use the labor allocator intact. Therefore, Mr. Johnson's recommendation to use a net plant allocator for Accounts 920-923 and 930.2 should be rejected.

i. Allocation of A&G Account 930.1

Q. CEP WITNESS JOHNSON ARGUES THAT ADVERTISING EXPENSE SHOULD NOT BE ALLOCATED BASED ON CUSTOMER COUNT. HE RECOMMENDS EITHER THE LABOR ALLOCATOR OR A NON-FUEL O&M ALLOCATOR BE USED INSTEAD. DO YOU AGREE?

A. No. While using the LABOR allocator is reasonable, I think it is also reasonable for advertising to be considered a customer-related cost that should be allocated on customer count. This issue was disputed in EPE's previous rate case and I agreed with several parties in that case (in rebuttal testimony) to change the allocation of advertising expense in the CCOS from a payroll allocator (LABOR) to a customer count allocator (CUSTOMER). In doing so, EPE aligned its allocation and classification treatment of advertising expense with EPE's JCOS study. There is no compelling reason to change that again.

j. Allocation of 69 KV Costs to 115 KV Customers

Q. PLEASE SUMMARIZE THE RECOMMENDATION MADE BY TIEC WITNESS HIGGINS REGARDING COSTS ASSOCIATED WITH EPE'S 69 KV TRANSMISSION SYSTEM.

A. TIEC witness Higgins recommends that EPE separate the costs of 69 kV, 115 kV, and above sub-functions for class cost of service purposes, and exclude customers served at 115 kV from the allocation of 69 kV costs.

Q. DO YOU AGREE WITH MR. HIGGINS' RECOMMENDATION?

A. No. EPE rejects the recommendation to allocate 69 kV and 115 kV costs any differently. This change in allocation would not accurately reflect the 115 kV customers' use of the 69 kV system. Refer to Robert C. Doyle's rebuttal testimony where he concludes that 115 kV-connected transmission customers do use and benefit from the interconnected 69 kV lines and should therefore share that cost.

I also must emphasize that EPE's accounting system does not separate the costs between 69 kV and 115 kV. EPE's ad hoc estimates using line miles or some other measure to respond to Requests for Information are not reflective of actual costs.

k. Distribution Cost Allocation

Q. OPUC WITNESS EVANS DISAPPROVES OF THE METHODOLOGY EPE'S CLASS COST OF SERVICE STUDY APPLIES IN ALLOCATION OF DISTRIBUTION-RELATED COSTS. IS EPE'S ALLOCATION METHOD REASONABLE?

A. Yes, it is. The distribution-related cost allocation methodology used in the Company's CCOS is consistent with the recommendation found in the NARUC Manual. According to page 97 of the Manual:

> *The load diversity at distribution substations and primary feeders is usually high. For this reason, customer-class peaks are normally used for the allocation of these facilities. The facilities nearer the customer, such as secondary feeders and line transformers, have much lower load diversity. They are normally allocated according to the individual customer's maximum demands.*

Q. WHAT IS OPUC WITNESS EVANS' RECOMMENDATION?

A. Mr. Evans recommends that secondary lines, line transformers, and associated costs be allocated among customer classes that are served at secondary voltages based upon MCD-based demand allocators instead of EPE's proposal to allocate using NCP-based demand allocators. While this proposal may have some merit, EPE believes its own approach is the most appropriate, as I will discuss next.

Q. HOW SHOULD THE PROPER METHODOLOGY BE SELECTED?

A. The choice of allocation methodologies is subjective and is often based on the particular circumstance of the utility. EPE is a summer-peaking utility. With air conditioning driving a significant amount of load, one must keep in mind that during hot summer days, there is a high likelihood that the air conditioning units of EPE residential customers that are served from the same transformer will operate at the same time. This makes EPE's secondary voltage Non-Coincident Peak ("NCP") allocation methodology wholly appropriate.

Additionally, as I stated earlier, EPE's methodology of allocating distribution-related costs is consistent with NARUC's recommendation, which I quoted above. Therefore, EPE stands by allocating primary voltage distribution-related costs using Maximum Class Demand ("MCD") and secondary voltage distribution-related costs using NCP.

l. Uncollectible Expense

Q. OPUC WITNESS EVANS RECOMMENDS THAT ACCOUNT 904 UNCOLLECTIBLE EXPENSE BE ALLOCATED ON SALES REVENUES AMONG ALL TEXAS RETAIL CUSTOMER CLASSES. DO YOU AGREE?

A. No. While EPE has selected to allocate uncollectible expenses based on the class revenue approach, EPE limits the allocation to each rate class that is "subject to" account balance write-offs. Rate classes that are not regarded as subject to account write-offs are those specifically serving governmental entities and large industrial customers. Mr. Evans' recommendation should be rejected because not all rate classes are subject to account write-offs.

m. Contributions and Donations

Q. PLEASE DESCRIBE TIEC WITNESS HIGGINS' RECOMMENDATION REGARDING CONTRIBUTIONS AND DONATIONS.

A. TIEC witness Higgins recommends that Contributions and Donations expense be allocated be allocated based on customer count. EPE has withdrawn its request for recovery of contributions and donations from its cost of service. Please see rebuttal testimonies of EPE witnesses Prieto and Borden.

VI. Staff's Cost of Service and Baseline Calculations

Q. HAVE YOU REVIEWED STAFF WITNESS NARVAEZ'S ATTACHMENTS INCLUDED WITH HIS DIRECT TESTIMONY?

A. Yes, I have. I reviewed Attachments AN-2, AN-3, and AN-4.

Q. DO YOU HAVE ANY ISSUES OR CORRECTIONS?

A. Yes. I do. While I have not looked closely at Staff's total company adjustments (refer to the rebuttal testimonies of Prieto and Borden for more detail related to the total company adjustments), I could not help but notice the allocation of income taxes (or lack thereof) in Staff Attachment AN-2.

I strongly disagree with how Staff Attachment AN-2 disallows any allocation of Arizona and New Mexico state income taxes to the Texas jurisdiction. Please see the rebuttal testimony of EPE witness Prieto for a discussion of income taxes and why they apply to Texas customers. Just like EPE allocates its costs related to Palo Verde generation and transmission (which is physically located in Arizona) to its New Mexico and Texas jurisdictions, income taxes should also be allocated in a similar fashion. It does not make sense to directly assign income taxes to each state. Arizona, for instance, is not even an EPE jurisdiction. This is a fundamental error in the allocation of costs, which puts into question the accuracy of Attachments AN-3 and AN-4. Therefore, I recommend that all parties use EPE's cost of service model and baseline calculations.

VII. REVISED BASELINE CALCULATIONS

Q. DID EPE UPDATE THE BASELINE CALCULATIONS ITS DCRF, TCRF, and GCRR?

A. Yes, I have included the updated baseline calculation using EPE's rebuttal cost of service. They are presented in the following exhibits:

- Exhibit AH-4R – DCRF Baseline
- Exhibit AH-5R – TCRF Baseline
- Exhibit AH-6R – GCRR Baseline

For the most part, EPE used the same approach to calculate the baseline calculations. One exception to EPE's approach was in the TCRF's rate class allocation. Instead of only using a 4CP transmission plant allocator as the basis to allocate to each rate class, EPE used a demand transmission allocator that is more consistent with its cost of service allocation of demand transmission costs. This update will include the lighting classes so that they get a small fractional allocation where before, when it was based solely on a 4CP transmission plant allocator, they were getting zero.

VIII. Conclusion

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes, it does.

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
			At Existing Rates		At Proposed Rates			
Line No.	Description	Total Per Books	Adjustments	As Adjusted	Adjustments	(Rebuttal) As Adjusted	(As Filed) As Adjusted	Rebuttal Adjustments
	Operating Revenues							
	Sales Revenues							
	Base Rate Revenues							
1	Base	$ 528,887,914	$ 5,686,206	$ 534,574,120	$ 35,693,538	$ 570,267,658	$ 574,531,417	$ (4,263,759)
2	Non-firm	3,642,224	361,503	4,003,727	-	4,003,727	4,174,343	(170,616)
3	Total Base Rate Revenues	532,530,138	6,047,709	538,577,847	35,693,538	574,271,385	578,705,760	(4,434,375)
4	Fuel Revenues from Retail Sales	81,322,716	(1,350,714)	79,972,002	-	79,972,002	80,084,706	(112,704)
5	Other Sales For Resale Fuel Revenues	65,727,609	97,318	65,824,927	-	65,824,927	65,919,767	65,824,927
6	Total Fuel Revenues	147,050,325	(1,253,395)	145,796,929	-	145,796,929	146,004,473	65,712,223
7	Other Sales For Resale Non-Fuel Revenues	-	-	-	-	-	-	-
8	Other Sales Margins Retained by EPE	-	-	-	-	-	-	-
9	Provision for Rate Refund	-	-	-	-	-	-	-
10	Total Sales Revenues	679,580,462	4,794,314	684,374,776	35,693,538	720,068,314	724,710,233	61,277,848
11	Other Operating Revenues	26,798,328	844,298	27,642,626	(720,634)	26,921,992	26,921,992	-
12	Total Operating Revenues	706,378,791	5,638,612	712,017,403	34,972,904	746,990,306	751,632,226	61,277,848
	Operating Expenses							
	Operation & Maintenance Expenses							
	Fuel and Purchased Power							
13	Reconcilable	147,472,535	(1,675,605)	145,796,929	-	145,796,929	146,004,473	(207,544)
14	Non-Reconcilable	1,426,324	3,247	1,429,570	-	1,429,570	1,431,449	(1,878)
15	Total Fuel and Purchased Power	148,898,858	(1,672,359)	147,226,500	-	147,226,500	147,435,922	(209,422)
16	Other Operation & Maintenance	250,738,400	(8,383,799)	242,354,601	91,523	242,446,124	243,174,207	(728,083)
17	Total Operation & Maintenance Expenses	399,637,258	(10,056,157)	389,581,101	91,523	389,672,624	390,610,129	(937,506)
18	Regulatory Debits and Credits	790,344	-	790,344		790,344	2,986,404	(2,196,060)
19	Depreciation & Amortization Expense	82,207,721	16,794,927	99,002,648	-	99,002,648	99,088,920	(86,273)
20	Decommissioning and Accretion Expense	7,963,676	(7,851,839)	111,836	-	111,836	111,981	(145)
21	Taxes Other Than Income Taxes	66,168,599	75,459	66,244,057	2,061,000	68,305,057	68,511,555	(206,498)
22	Current Income Taxes							
23	Federal	10,004,848	2,795,881	12,800,728	6,399,556	19,200,285	19,368,450	(168,165)
24	State	1,525,596	242,035	1,767,631	751,487	2,519,119	2,533,565	(14,446)
25	Total Current Income Taxes	11,530,444	3,037,916	14,568,360	7,151,043	21,719,403	21,902,015	(182,611)
26	Deferred Income Taxes							
27	Federal	9,462,051	(3,748,274)	5,713,777	-	5,713,777	5,721,725	(7,948)
28	State	613,658	380,224	993,882	-	993,882	995,013	(1,131)
29	Other							
30	Total Deferred Income Taxes	10,075,709	(3,368,050)	6,707,659	-	6,707,659	6,716,738	(9,079)
31	Amortization of Investment Tax Credits	(1,309,809)	(194,185)	(1,503,995)	-	(1,503,995)	(1,505,971)	1,976
32	Total Operating Expenses	$ 577,063,941	$ (1,561,931)	$ 575,502,010	$ 9,303,567	$ 584,805,577	$ 588,421,772	$ (3,616,195)
33	Operating Income (Return)	$ 129,314,849	$ 7,200,543	$ 136,515,392	$ 25,669,337	$ 162,184,729	$ 163,210,454	$ (1,025,725)
34	Total Cost of Service	$ 706,378,791	5,638,612	$ 712,017,403	34,972,904	$ 746,990,306	$ 751,632,226	$ (4,641,919)
35	Rate Base (Schedule B-1.1)	$ 2,039,760,521	$ (9,158,884)	$ 2,030,601,636	$ 454,782	$ 2,031,056,418	$ 2,043,901,676	$ (12,845,258)
36	Rate of Return on Rate Base	6.340%		6.723%		7.985%	7.985%	0.000%
37	Revenue Deficiency @ Proposed ROR on Rate Base	$ 40,611,516		$ 34,972,904		$ -		

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

Line No.	(a) Description	(b) Test Year Actual Per Books	(c) Adjustments	(d) Adjusted Rate Base	(e) To Reflect Rate Relief	(f) (Rebuttal) Requested Rate Base	(g) (As Filed) Requested Rate Base	(h) Rebuttal Adjustments
	Rate Base							
1	Plant in Service	$ 4,324,322,144	$ (662,272,829)	$ 3,662,049,315	$ -	$ 3,662,049,315	$ 3,665,210,259	$ (3,160,944)
2	Accum Depreciation & Amortization	(1,942,733,526)	720,073,582	(1,222,659,943)	-	(1,222,659,943)	(1,223,765,542)	1,105,598
	Net Plant In Service	2,381,588,619	57,800,753	2,439,389,372	-	2,439,389,372	2,441,444,718	(2,055,346)
	Additions to Rate Base							
3	CWIP	-	-	-	-	-	-	-
4	Working Cash	-	(4,153,725)	(4,153,725)	454,782	(3,698,944)	(2,622,625)	(1,076,319)
5	Fuel Inventory	1,397,522	(526,593)	870,928	-	870,928	1,393,806	(522,878)
6	Nuclear Fuel	99,814,678	(99,814,678)	-	-	-	-	-
7	Materials & Supplies	51,598,364	(3,105,851)	48,492,512	-	48,492,512	48,530,177	(37,664)
8	Prepayments	15,066,080	(256,309)	14,809,771	-	14,809,771	14,822,703	(12,932)
9	Coal Reclamation Asset	1,651,329	(1,651,329)	-	-	-	-	-
10	Regulatory Assets	8,649,581	(8,649,581)	0	-	0	9,523,392	(9,523,391)
11	Accumulated Deferred Income Taxes	137,260,267	(33,806,103)	103,454,164	-	103,454,164	103,531,111	(76,946)
12	Tax Regulatory Assets	39,131,344	(26,542,850)	12,588,494	-	12,588,494	12,599,100	(10,607)
13	Miscellaneous Deferred Debits	4,299,875	(447,244)	3,852,631	-	3,852,631	3,857,693	(5,062)
	Total Additions to Rate Base	358,869,040	(178,954,264)	179,914,777	454,782	180,369,558	191,635,357	(11,265,799)
	Deductions to Rate Base							
14	Customer Deposits	(5,614,572)	(59)	(5,614,631)	-	(5,614,631)	(5,614,688)	57
15	Regulatory Liabilities	(18,580,117)	18,580,117	-	-	-	-	-
16	Tax Regulatory Liabilities	(225,605,731)	3,443,836	(222,161,896)	-	(222,161,896)	(222,349,082)	187,186
17	Customer Advances - Construction	(25,033,070)	-	(25,033,070)	-	(25,033,070)	(25,033,070)	-
18	Accumulated Deferred Income Taxes	(425,863,648)	89,970,732	(335,892,916)	-	(335,892,916)	(336,181,559)	288,643
	Total Deductions from Rate Base	(700,697,138)	111,994,626	(588,702,512)	-	(588,702,512)	(589,178,399)	475,886
19	Total Rate Base	$ 2,039,760,521	$ (9,158,884)	$ 2,030,601,636	$ 454,782	$ 2,031,056,418	$ 2,043,901,676	$ (12,845,258)
20	Return on Rate Base					162,184,729	163,210,454	(1,025,725)
21	Rate of Return on Rate Base					7.985%	7.985%	

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

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JURISDICTIONAL COST OF SERVICE STUDY SUMMARY
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Revenues and Expenses

	Total Company Test Year Total	Texas Test Year Total	Other Test Year Total
Operating Revenues	963,490	746,990	216,500
Operation & Maintenance Expenses			
Fuel & Purchased Power	199,908	147,226	52,681
Production (Excl. Fuel & Purchased Power	146,500	117,209	29,291
Transmission	23,792	18,905	4,887
Distribution	26,230	19,733	6,497
Customer Services	19,285	15,466	3,820
Administration & General	99,496	71,099	28,397
Other	83	34	49
Total Operation & Maintenance Expenses	515,294	389,673	125,622
Depreciation & Amortization			
Production	61,556	49,362	12,193
Transmission	9,421	7,489	1,932
Distribution	31,521	23,107	8,414
General Plant	16,005	12,628	3,377
Intangible Amortization	8,142	6,417	1,725
Total Depreciation & Amortization	126,644	99,003	27,641
Taxes Other Than Income Taxes	76,701	68,305	8,396
Regulatory Debits and Credits	2,239	790	1,448
Decommissioning and Accretion Expense	138	112	26
Pre-tax Expenses	721,016	557,883	163,133
Income Taxes			
State	4,492	3,513	979
Federal	30,410	23,410	7,000
Total Income Taxes	34,903	26,923	7,980
Total Operating Expenses	755,919	584,806	171,113
Operating Income	207,572	162,185	45,387
Total Cost of Service	**963,490**	**746,990**	**216,500**
Less: Total Revenues @ Present Rates	915,768	712,017	203,750
Total Operating Revenue Deficiency	47,722	34,973	12,750
Total Revenue Percent Increase	5.2%	4.9%	6.3%
Total Cost of Service	**963,490**	**746,990**	**216,500**
Excluding Fuel & Purchased Power and Other Operating Revenue	248,128	172,719	75,409
Less: Non-Fuel Base Revenues @ Present Rates	666,919	538,578	128,342
Non-Fuel Base Revenue Deficiency @ Equalized Rate of Return	48,443	35,694	12,750
Percent Increase Required	7.3%	6.6%	9.9%

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Rate Base and Return

	Total Company Test Year Total	Texas Test Year Total	Other Test Year Total
Plant In Service			
Intangible	119,028	93,913	25,114
Production	2,330,454	1,872,889	457,565
Transmission	555,283	441,426	113,858
Distribution	1,427,591	1,050,173	377,418
General Plant	258,130	203,648	54,483
Total Plant In Service	4,690,486	3,662,049	1,028,437
Accumulated Depreciation & Amortization			
Intangible	(78,414)	(61,430)	(16,984)
Production	(746,857)	(603,819)	(143,038)
Transmission	(242,771)	(192,992)	(49,779)
Distribution	(411,153)	(287,838)	(123,315)
General Plant	(97,020)	(76,581)	(20,439)
Total Accumulated Depr & Amort.	(1,576,215)	(1,222,660)	(353,555)
Net Plant In Service	3,114,271	2,439,389	674,882
Additions (Deductions) to Rate Base			
Working Capital	76,493	60,474	16,019
Other Additions	162,341	119,895	42,445
Other Deductions	(753,664)	(588,703)	(164,962)
Rate Base	2,599,440	2,031,056	568,384
Operating Income	207,572	162,185	45,387
Rate of Return	7.985%	7.985%	7.985%

Totals may not tie to other schedules due to rounding.

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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	**746,990**	401,874	37,691	704	3,919	149	14,476	4,087	671
Operation & Maintenance Expenses									
Fuel & Purchased Power	**147,226**	59,262	6,373	85	839	48	3,983	1,755	90
Production (Excl. Fuel & Purchased Power)	**117,209**	58,077	5,452	50	482	29	2,532	694	96
Transmission	**18,905**	10,359	894	4	7	3	308	101	17
Distribution	**19,733**	12,498	1,111	59	364	2	345	0	23
Customer Services	**15,466**	13,031	1,456	11	8	2	22	0	9
Administration & General	**71,099**	43,597	4,408	79	455	12	1,084	228	64
Other	**34**	30	3	0	0	0	0	0	0
Total Operation & Maintenance Expenses	**389,673**	196,854	19,696	289	2,154	96	8,275	2,778	300
Depreciation & Amortization									
Production	**49,362**	27,152	2,322	12	113	8	794	255	47
Transmission	**7,489**	4,160	354	0	0	1	119	39	7
Distribution	**23,107**	14,274	1,196	77	304	2	465	0	31
General Plant	**12,628**	7,747	784	15	86	2	195	39	11
Intangible Amortization	**6,417**	3,903	388	8	44	1	100	21	6
Total Depreciation & Amortization	**99,003**	57,235	5,044	111	547	15	1,673	354	102
Taxes Other Than Income Taxes	**68,305**	38,227	3,470	64	339	12	1,219	306	66
Regulatory Debits and Credits	**790**	433	37	0	2	0	13	4	1
Decommissioning and Accretion Expense	**112**	62	5	0	0	0	2	1	0
Pre-tax expenses	**557,883**	292,812	28,253	464	3,043	122	11,181	3,442	468
Income Taxes									
State	**3,513**	2,026	175	4	16	0	61	12	4
Federal	**23,410**	13,574	1,183	31	113	3	408	77	25
Total Income Taxes	**26,923**	15,600	1,358	36	130	4	469	89	29
Total Expenses	**584,806**	308,412	29,611	500	3,173	126	11,650	3,531	497
Operating Income	**162,185**	93,462	8,079	204	747	23	2,826	556	174
Total Cost of Service	**746,990**	401,874	37,691	704	3,919	149	14,476	4,087	671
Excluding Fuel & Purchased Power and Other Operating Revenue	**172,719**	74,324	7,706	96	885	51	4,351	1,856	115
Less: Non-Fuel Base Revenues @ Present Rates	**538,578**	275,863	33,509	463	4,047	96	10,166	1,851	427
Non-Fuel Base Revenue Deficiency @ Equalized Rate of Return	**35,694**	51,687	(3,524)	145	(1,012)	2	(40)	380	129
Percent Increase Required	**6.6%**	18.7%	-10.5%	31.4%	-25.0%	2.2%	-0.4%	20.5%	30.2%

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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	152,379	54,277	21,925	3,271	5,610	23,063	216	21,714	965
Operation & Maintenance Expenses									
Fuel & Purchased Power	33,859	15,693	8,494	624	4,041	7,426	37	4,499	119
Production (Excl. Fuel & Purchased Power)	26,350	9,757	4,421	358	403	4,742	21	3,677	71
Transmission	4,016	1,322	541	5	68	673	1	579	5
Distribution	3,321	893	0	476	0	0	16	519	105
Customer Services	754	61	0	35	0	0	1	44	30
Administration & General	12,160	3,865	1,331	208	143	1,535	19	1,755	157
Other	1	0	0	0	0	0	0	0	0
Total Operation & Maintenance Expenses	80,461	31,591	14,787	1,707	4,654	14,377	95	11,073	486
Depreciation & Amortization									
Production	10,369	3,398	1,380	84	168	1,724	5	1,511	19
Transmission	1,574	512	206	0	26	260	0	230	2
Distribution	4,412	1,193	0	365	0	0	22	688	78
General Plant	2,158	685	232	38	25	265	4	312	30
Intangible Amortization	1,123	356	119	19	13	138	2	163	15
Total Depreciation & Amortization	19,637	6,144	1,937	506	231	2,388	32	2,903	144
Taxes Other Than Income Taxes	13,753	4,581	1,678	271	296	1,919	19	1,998	85
Regulatory Debits and Credits	166	55	22	2	3	28	0	24	0
Decommissioning and Accretion Expense	23	8	3	0	0	4	0	3	0
Pre-tax expenses	114,040	42,379	18,429	2,485	5,185	18,715	146	16,002	716
Income Taxes									
State	712	221	65	15	8	81	1	106	5
Federal	4,708	1,456	418	99	51	518	9	702	33
Total Income Taxes	5,420	1,677	483	114	58	599	10	808	38
Total Expenses	119,460	44,056	18,912	2,599	5,243	19,314	156	16,810	754
Operating Income	32,919	10,220	3,013	672	366	3,749	60	4,904	211
Total Cost of Service	152,379	54,277	21,925	3,271	5,610	23,063	216	21,714	965
Excluding Fuel & Purchased Power and Other Operating Revenue	38,822	17,212	9,038	653	4,108	8,111	40	5,185	166
Less: Non-Fuel Base Revenues @ Present Rates	125,847	36,727	11,075	2,933	1,205	14,512	133	19,249	476
Non-Fuel Base Revenue Deficiency @ Equalized Rate of Return	(12,290)	338	1,812	(315)	296	440	43	(2,721)	323
Percent Increase Required	-9.8%	0.9%	16.4%	-10.7%	24.6%	3.0%	32.3%	-14.1%	68.0%

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	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	**93,913**	63,120	6,934	120	589	15	1,135	199	81
Production	**1,872,889**	1,029,918	88,092	450	4,406	307	30,145	9,683	1,784
Transmission	**441,426**	245,196	20,868	0	0	57	6,997	2,274	425
Distribution	**1,050,173**	649,658	54,451	3,545	14,432	109	21,244	1	1,384
General Plant	**203,648**	124,929	12,650	240	1,390	34	3,139	636	184
Total Plant In Service	**3,662,049**	2,112,821	182,996	4,354	20,817	522	62,660	12,792	3,859
Accumulated Depreciation & Amortization									
Intangible	**(61,430)**	(38,067)	(3,745)	(93)	(568)	(9)	(967)	(157)	(59)
Production	**(603,819)**	(331,476)	(28,376)	(170)	(1,662)	(103)	(9,744)	(3,124)	(574)
Transmission	**(192,992)**	(107,200)	(9,124)	0	0	(25)	(3,059)	(994)	(186)
Distribution	**(287,838)**	(180,782)	(15,469)	(907)	(6,523)	(29)	(5,315)	(0)	(356)
General Plant	**(76,581)**	(46,979)	(4,757)	(90)	(523)	(13)	(1,181)	(239)	(69)
Total Accumulated Depr & Amort.	**(1,222,660)**	(704,504)	(61,470)	(1,260)	(9,276)	(179)	(20,265)	(4,515)	(1,244)
Net Plant In Service	**2,439,389**	1,408,318	121,525	3,094	11,541	343	42,395	8,278	2,615
Additions (Deductions) to Rate Base									
Working Capital	**60,474**	34,486	3,009	79	390	9	1,071	218	63
Other Additions	**119,895**	70,169	6,236	162	671	17	2,058	383	126
Other Deductions	**(588,703)**	(342,537)	(29,593)	(774)	(3,248)	(82)	(10,139)	(1,921)	(629)
Rate Base	**2,031,056**	1,170,436	101,177	2,560	9,354	288	35,385	6,958	2,175
Operating Income	**162,185**	93,462	8,079	204	747	23	2,826	556	174
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 - REBUTTAL
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	12,955	3,775	1,124	267	128	1,324	24	1,869	256
Production	393,429	128,954	52,400	3,278	6,367	65,421	200	57,322	732
Transmission	92,766	30,163	12,158	0	1,507	15,348	5	13,550	112
Distribution	202,105	54,844	4	12,469	1	5	985	31,595	3,343
General Plant	34,806	11,053	3,736	612	397	4,277	57	5,024	485
Total Plant In Service	736,060	228,790	69,421	16,627	8,400	86,374	1,270	109,359	4,928
Accumulated Depreciation & Amortization									
Intangible	(10,495)	(3,231)	(915)	(218)	(99)	(1,055)	(23)	(1,538)	(189)
Production	(126,833)	(41,628)	(16,938)	(1,237)	(2,052)	(21,108)	(74)	(18,471)	(250)
Transmission	(40,557)	(13,187)	(5,315)	0	(659)	(6,710)	(2)	(5,924)	(49)
Distribution	(51,114)	(13,503)	(2)	(4,606)	(1)	(3)	(243)	(7,918)	(1,067)
General Plant	(13,089)	(4,156)	(1,405)	(230)	(149)	(1,608)	(21)	(1,889)	(182)
Total Accumulated Depr & Amort.	(242,088)	(75,707)	(24,576)	(6,291)	(2,959)	(30,484)	(363)	(35,741)	(1,738)
Net Plant In Service	493,972	153,083	44,845	10,336	5,441	55,890	907	73,618	3,189
Additions (Deductions) to Rate Base									
Working Capital	12,248	3,871	1,200	302	159	1,448	23	1,811	87
Other Additions	23,568	7,292	2,107	530	250	2,586	46	3,503	190
Other Deductions	(117,541)	(36,258)	(10,418)	(2,758)	(1,263)	(12,973)	(224)	(17,523)	(820)
Rate Base	412,246	127,988	37,734	8,410	4,587	46,952	751	61,409	2,646
Operating Income	32,919	10,220	3,013	672	366	3,749	60	4,904	211
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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		Total Texas Distribution Function	Reference
1	**Distribution Invested Capital (DIC)**		
2	Distribution Gross Plant In Service	$ 1,090,791,194	L35
3	Distribution Accum Depr (Plant ACCT 360-374)	$ (287,838,113)	Schedule P-3
4	Distribution Accum Amort (Plant ACCT 303)	$ (25,652,590)	Schedule P-3 Dist related amount (plus share of general)
5	Distribution Accum Depr (Plant ACCT 391)	$ (3,357,023)	P-3 Acct 391 x Dist % of LABOR
6	Distribution Accum Depr (Plant ACCT 397)	$ (3,161,421)	P-3 Acct 399 x Dist % of LABOR
7	Accumulated Deferred Income Taxes	$ (126,867,467)	Schedule P-3
8	Current Net Distribution Invested Capital (DIC_C)	$ 643,914,580	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	$ 51,418,125	L8*L9
11	**Distribution Expenses**		
12	Distribution Depreciation Expense ($DEPR_C$)	$ 26,697,057	Schedule P-2
13	Property taxes	$ 5,080,112	Schedule P-2
14	**Federal Income Tax Expense**		
15	Return	$ 51,418,125	L10
16	Interest synchronization	$ (17,688,402)	L8* Interest Sync Rate
17	Permanent and flow through differences	$ 1,445,032	(Federal Perms + Excess Deferred Taxes) * L39
18	Taxable income	$ 35,174,755	L15+L16+L17
19	Income tax factor	0.265823	
20	Taxes before credits	$ 9,350,251	L18*L19
21	Excess deferred income taxes	$ (944,851)	Schedule P-2 * L39
22	Federal Income Tax Expense	$ 8,405,401	L20+L21
23	**Revenue Related Taxes Excl. Municipal Franchise Fees**		
24	Revenue Requirements before revenue taxes	$ 91,600,694	L10+L12+L13+L22
25	Revenue tax gross up factor	1.04926388	
26	Revenue Requirements before credits	$ 96,113,299	L24*L25
27	Texas revenue tax rate excluding municipal franchise fees	0.013194387	
28	Revenue taxes excluding municipal franchise fees	$ 1,268,156	L26*27
29	Total Distribution Baseline Revenue Requirement (DISTREV)	$ 92,868,850	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)	$ 25,950,116	Schedule P-3, See WP
33	General Plant (Plant Acct 391)	$ 7,003,693	P-3 Acct 391 x Dist % of LABOR
34	General Plant (Plant Acct 397)	$ 7,663,906	P-3 Acct 399 x Dist % of LABOR
35	Distribution Gross Plant In Service	$ 1,090,791,194	L31+L32+L33+L34
36			
37	Gross Plant In Service	$ 3,662,049,315	Schedule P-3
38	Gross Distribution Plant Allocator	28.68%	L31/L37
39	Net Distribution Plant Allocator	31.25%	P-3 (Net Dist Plt/Net Plt)

40	**Development of Distribution Rate Class Allocators**	Balances	$ALLOC_{CLASS}$	$DISTREV_{RC-CLASS}$	Reference (Balances column)	Reference (DISTREV Column)
41	Rate 01 Residential	$ 649,657,876			Schedule P-3	
42	Rate 01 Residential Intangible	$ 17,023,074			Line 32 * DISTLABOR	
43	Rate 01 Residential General Plant 391	$ 4,594,368			Line 33 * DISTLABOR	
44	Rate 01 Residential General Plant 397	$ 5,027,463	62.0011%	$ 57,579,729	Line 34 * DISTLABOR	L29*$ALLOC_{CLASS}$
45	Rate 02 Small General Service	$ 54,451,246			Schedule P-3	
46	Rate 02 Small General Service Intangible	$ 1,542,049			Line 32 * DISTLABOR	
47	Rate 02 Small General Service General Plant 391	$ 416,185			Line 33 * DISTLABOR	
48	Rate 02 Small General Service General Plant 397	$ 455,417	5.2132%	$ 4,841,419	Line 34 * DISTLABOR	L29*$ALLOC_{CLASS}$
49	Rate 07 Recreational Lighting	$ 3,544,743			Schedule P-3	
50	Rate 07 Recreational Lighting Intangible	$ 75,843			Line 32 * DISTLABOR	
51	Rate 07 Recreational Lighting General Plant 391	$ 20,469			Line 33 * DISTLABOR	
52	Rate 07 Recreational Lighting General Plant 397	$ 22,399	0.3359%	$ 311,903	Line 34 * DISTLABOR	L29*$ALLOC_{CLASS}$
53	Rate 08 Street Lighting	$ 14,432,263			Schedule P-3	
54	Rate 08 Street Lighting Intangible	$ 505,205			Line 32 * DISTLABOR	
55	Rate 08 Street LightingGeneral Plant 391	$ 136,350			Line 33 * DISTLABOR	
56	Rate 08 Street LightingGeneral Plant 397	$ 149,203	1.3956%	$ 1,296,073	Line 34 * DISTLABOR	L29*$ALLOC_{CLASS}$
57	Rate 09 Traffic Signals	$ 109,079			Schedule P-3	
58	Rate 09 Traffic Signals Intangible	$ 2,577			Line 32 * DISTLABOR	
59	Rate 09 Traffic Signals General Plant 391	$ 695			Line 33 * DISTLABOR	
60	Rate 09 Traffic Signals General Plant 397	$ 761	0.0104%	$ 9,630	Line 34 * DISTLABOR	L29*$ALLOC_{CLASS}$
61	Rate 11-TOU Municipal Pumping	$ 21,243,809			Schedule P-3	
62	Rate 11-TOU Municipal Pumping Intangible	$ 435,588			Line 32 * DISTLABOR	
63	Rate 11-TOU Municipal Pumping General Plant 391	$ 117,561			Line 33 * DISTLABOR	
64	Rate 11-TOU Municipal Pumping General Plant 397	$ 128,643	2.0101%	$ 1,866,723	Line 34 * DISTLABOR	L29*$ALLOC_{CLASS}$

			$ALLOC_{CLASS}$	$DISTREV_{RC\text{-}CLASS}$	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	$ 1,384,075			Schedule P-3	
71	Rate 22 Irrigation Service Intangible	$ 30,051			Line 32 * DISTLABOR	
72	Rate 22 Irrigation Service General Plant 391	$ 8,110			Line 33 * DISTLABOR	
73	Rate 22 Irrigation Service General Plant 397	$ 8,875	0.1312%	$ 121,843	Line 34 * DISTLABOR	$L29*ALLOC_{CLASS}$
74	Rate 24 General Service	$ 202,104,616			Schedule P-3	
75	Rate 24 General Service Intangible	$ 4,218,455			Line 32 * DISTLABOR	
76	Rate 24 General Service General Plant 391	$ 1,138,522			Line 33 * DISTLABOR	
77	Rate 24 General Service General Plant 397	$ 1,245,846	19.1336%	$ 17,769,138	Line 34 * DISTLABOR	$L29*ALLOC_{CLASS}$
78	Rate 25 Large Power	$ 54,844,271			Schedule P-3	
79	Rate 25 Large Power Intangible	$ 1,123,063			Line 32 * DISTLABOR	
80	Rate 25 Large Power General Plant 391	$ 303,104			Line 33 * DISTLABOR	
81	Rate 25 Large Power General Plant 397	$ 331,677	5.1891%	$ 4,819,046	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%	$ 382	Line 34 * DISTLABOR	$L29*ALLOC_{CLASS}$
86	Rate 28 Area Lighting	$ 12,469,005			Schedule P-3	
87	Rate 28 Area Lighting Intangible	$ 157,082			Line 32 * DISTLABOR	
88	Rate 28 Area Lighting General Plant 391	$ 42,395			Line 33 * DISTLABOR	
89	Rate 28 Area Lighting General Plant 397	$ 46,392	1.1657%	$ 1,082,531	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	$ 984,734			Schedule P-3	
99	Rate 34 Cotton Gin Intangible	$ 20,005			Line 32 * DISTLABOR	
100	Rate 34 Cotton Gin General Plant 391	$ 5,399			Line 33 * DISTLABOR	
101	Rate 34 Cotton Gin General Plant 397	$ 5,908	0.0931%	$ 86,505	Line 34 * DISTLABOR	$L29*ALLOC_{CLASS}$
102	Rate 41 City and County	$ 31,594,568			Schedule P-3	
103	Rate 41 City and County Intangible	$ 657,300			Line 32 * DISTLABOR	
104	Rate 41 City and County General Plant 391	$ 177,399			Line 33 * DISTLABOR	
105	Rate 41 City and County General Plant 397	$ 194,122	2.9908%	$ 2,777,522	Line 34 * DISTLABOR	$L29*ALLOC_{CLASS}$
106	RWH Water Heating	$ 3,342,869			Schedule P-3	
107	RWH Water Heating Intangible	$ 158,515			Line 32 * DISTLABOR	
108	RWH Water Heating General Plant 391	$ 42,782			Line 33 * DISTLABOR	
109	RWH Water Heating General Plant 394	$ 46,815	0.3292%	$ 305,732	Line 34 * DISTLABOR	$L29*ALLOC_{CLASS}$
110	Distribution Gross Plant In Service	$ 1,090,791,194	100.0000%	$ 92,868,850		

Intangible Plant

Description	Allocator	Texas Jurisdiction	Distribution Allocation	Distribution	Reference
Misc. Intangible Plant	CUSTLABOR	27,275,344	0.00%		P-3
Misc. Intangible Plant	D1PROD	672,239	0.00%		P-3
Misc. Intangible Plant	D2PROD	176,093	0.00%		P-3
Misc. Intangible Plant	PRODLABOR	1,848,111	0.00%		P-3
Misc. Intangible Plant	RG_PRODLABOR	201,851	0.00%		P-3
Misc. Intangible Plant	DISTLABOR	17,497,264	100.00%	17,497,264	P-3
Misc. Intangible Plant	TRANLABOR	15,608,659	0.00%		P-3
Misc. Intangible Plant	LABOR	30,633,937	27.59%	8,452,853	P-3, P-10
Total		93,913,497	27.6319%	25,950,116	

Accumulated Deferred Income Taxes

Allocator	Federal	State	Texas Jurisdiction	Distribution Allocation	Distribution	Reference
D1PROD	-	-	-	0.00%	-	P-3
DISTPLT	6,727,788	578,117	7,305,905	100.00%	7,305,905	P-3
E2ENERGY	1	0	1	0.00%	-	P-3
GROSSPLT	(249,894,506)	(22,605,279)	(272,499,786)	28.68%	(78,145,329)	P-3; GROSSPLT ALLOCATOR
LABOR	19,429,449	1,632,334	21,061,783	27.59%	5,811,599	P-3; LABOR ALLOCATOR
NETPLT	(194,653,444)	(3,226,613)	(197,880,056)	31.25%	(61,839,642)	P-3; NETPLT ALLOCATOR
FAS 109 Incremental - NetPlt	0	-	0	31.25%	0	P-3; NETPLT ALLOCATOR
	(418,390,712)	(23,621,441)	(442,012,153)		(126,867,467)	

Depreciation Expense	Allocator	Texas Jurisdiction	Distribution Allocation	Distribution	Reference
Distribution plant		23,106,781	100.00%	23,106,781	P-2
Intangible Amort. - Acct 303	D1PROD	66,257	0.00%	-	P-2
	D2PROD	3,246	0.00%	-	P-2
	PRODLABOR	49,538	0.00%	-	P-2
	RG_PRODLABOR	7,349	0.00%	-	P-2
	TRANLABOR	687,418	0.00%	-	P-2
	DISTLABOR	413,156	100.00%	413,156	P-2
	CUSTLABOR	41,149	0.00%	-	P-2
	LABOR	5,148,737	27.59%	1,420,696	P-2
Subtotal		6,416,851		1,833,852	
Office furniture and equip - Acct 391	LABOR	4,027,003	27.58%	1,110,487	P-2
Communication equip - Acct. 397	LABOR	2,342,383	27.58%	645,936	P-2
Total Depreciation		35,893,018		26,697,057	

Property Taxes

Description	Allocator	Texas Jurisdiction	Allocation to Distribution	Distribution	
AZ Property Taxes	D1PROD	(7,627)	0.00%	-	P-2
AZ Property Taxes	D2TRAN	5,447,616	0.00%	-	P-2
NM Property Taxes	D1PROD	-	0.00%	-	P-2
NM Property Taxes	LABOR	152,377	27.59%	42,045	P-2
NM Property Taxes	PRODPLT	1,884,746	0.00%	-	P-2
NM Property Taxes	D2TRAN	329,862	0.00%	-	P-2
TX Property Taxes	DISTPLT	4,847,407	100.00%	4,847,407	P-2
TX Property Taxes	LABOR	690,968	27.59%	190,659	P-2
TX Property Taxes	PRODPLT	8,546,564	0.00%	-	P-2
TX Property Taxes	D2TRAN	1,495,792	0.00%	-	P-2
Total		23,387,704		5,080,112	

LABOR ALLOCATOR (Schedule P-10)

Production O&M	13,608,521	33.74%
Transmission O&M	8,556,532	21.21%
Distribution O&M	11,130,170	27.59%
Customer O&M	7,041,567	17.46%
	40,336,789	100.00%

		TCRF Baseline - Texas Jurisdiction	Reference
1	**Return on Transmission Invested Costs (TIC)**		
2	Transmission Gross Plant In Service	$ 441,425,533	L36
3	Transmission Accum Depr (Plant ACCT 350-359)	$ (192,991,839)	Schedule P-3
4	Transmission Invested Costs (TIC)	$ 248,433,695	L2+L3
5	Accumulated Deferred Income Taxes	$ (48,539,084)	See Page 2
6	TIC net of ADIT	$ 199,894,611	L4+L5
7	Weighted Average Cost of Capital (WACC)	7.985%	Schedule K-1
8	Return on TIC net of ADIT	$ 15,962,064	L6*L7
9	**Operating Expenses**		
10	Transmission Depreciation Expense	$ 7,488,913	Schedule P-2
11			
12	Property taxes	7,452,167	See Page 2
13	**Income and Other Taxes**		
14	Return	$ 15,962,064	L8
15	Interest synchronization	$ (5,491,126)	L6* Interest Sync rate
16	Permanent and flow through differences	$ 470,914	(Federal Perms - Excess Deferred Taxes) * L41
17	Taxable income	$ 10,941,853	L14+L15+L16
18	Income tax factor	0.266966	Federal and State
19	Taxes before credits	$ 2,921,105	
20	Excess deferred income taxes	$ (307,913)	Schedule P-2 * L41
21	Income tax expense	$ 2,613,193	L19+L20
22	Revenue Requirements before revenue taxes and credits	$ 33,516,337	L8+L15+L17+L21
23	Revenue tax gross up factor	1.04926388	WP A-3 Adj. 01
24	Revenue Requirements before credits	$ 35,167,482	L22*L23
25	Texas revenue tax rate	0.043187201	WP A-3 Adj. 17
26	Revenue taxes	$ 1,518,785	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**	**$ 15,525,224**	L22+L26+L30
32	**Approved Transmission Charges (ATC)**		
33	Transmission of electricity by others (Account 565)	5,348,990	Schedule P-2
34	Total TCRF Baseline **(RR)**	$ 20,874,214	L31+L33 [revreqt + ATC]
35	**Development of Transmission Plant Allocators**		
36	Transmission Gross Plant In Service	$ 441,425,533	Schedule P-3
37	Gross Plant In Service	$ 3,662,049,315	Schedule P-3
38	Transmission Gross Plant Allocator	12.05%	L36/L37
39	Transmission Net Plant In Service	$ 248,433,695	Schedule P-3
40	Net Plant In Service	$ 2,439,389,372	Schedule P-3
41	Transmission Net Plant Allocator	10.18%	L39/L40
42			

43	**Transmission Rate Class Allocation**	RR	*Class* ALLOC	Reference (RR Column)	Balances	Reference (Class ALLOC column)
44	Rate 01 Residential	$ 11,756,645	56.3214%	L34*ClassALLOC	$ 33,765,643	DEM TRAN (P-6)
45	Rate 02 Small General Service	$ 1,075,910	5.1543%	L34*ClassALLOC	$ 3,090,064	DEM TRAN (P-6)
46	Rate 07 Recreational Lighting	$ 8,806	0.0422%	L34*ClassALLOC	$ 25,292	DEM TRAN (P-6)
47	Rate 08 Street Lighting	$ 8,854	0.0424%	L34*ClassALLOC	$ 25,428	DEM TRAN (P-6)
48	Rate 09 Traffic Signals	$ 3,052	0.0146%	L34*ClassALLOC	$ 8,767	DEM TRAN (P-6)
49	Rate 11-TOU Municipal Pumping	$ 331,985	1.5904%	L34*ClassALLOC	$ 953,477	DEM TRAN (P-6)
50	Rate 15 Electric Refining	$ 112,799	0.5404%	L34*ClassALLOC	$ 323,965	DEM TRAN (P-6)
51	Rate 22 Irrigation Service	$ 18,930	0.0907%	L34*ClassALLOC	$ 54,369	DEM TRAN (P-6)
52	Rate 24 General Service	$ 4,130,458	19.7874%	L34*ClassALLOC	$ 11,862,871	DEM TRAN (P-6)
53	Rate 25 Large Power	$ 1,355,605	6.4942%	L34*ClassALLOC	$ 3,893,361	DEM TRAN (P-6)
54	Rate 26 Petroleum Refinery	$ 622,162	2.9805%	L34*ClassALLOC	$ 1,786,877	DEM TRAN (P-6)
55	Rate 28 Area Lighting	$ 6,614	0.0317%	L34*ClassALLOC	$ 18,996	DEM TRAN (P-6)
56	Rate 30 Electric Furnace	$ 79,522	0.3810%	L34*ClassALLOC	$ 228,392	DEM TRAN (P-6)
57	Rate 31 Military Reservation	$ 746,583	3.5766%	L34*ClassALLOC	$ 2,144,222	DEM TRAN (P-6)
58	Rate 34 Cotton Gin	$ 1,912	0.0092%	L34*ClassALLOC	$ 5,492	DEM TRAN (P-6)
59	Rate 41 City and County	$ 595,747	2.8540%	L34*ClassALLOC	$ 1,711,015	DEM TRAN (P-6)
60	RWH Water Heating	$ 18,628	0.0892%	L34*ClassALLOC	$ 53,502	DEM TRAN (P-6)
61	Total TCRF Baseline **(RR)**	$ 20,874,214	100.0000%		$ 59,951,732	

EL PASO ELECTRIC COMPANY
2021 TEXAS RATE CASE - REBUTTAL
TRANSMISSION COST RECOVERY FACTOR BASELINE
Allocation of ADIT and Property Taxes
Transmission Plant

Function	Federal	State	Total	Allocation to Transmission	Transmission	Reference
ADIT						
D1PROD	-	-	-	0.00%	-	P-3
DISTPLT	6,727,788	578,117	7,305,905	0.00%	-	P-3
E2ENERGY	1	0	1	0.00%	-	P-3
GROSSPLT	(249,894,506)	(22,605,279)	(272,499,786)	12.05%	(32,847,281)	P-3
LABOR	19,429,449	1,632,334	21,061,783	21.21%	4,467,778	P-3
NETPLT	(194,653,444)	(3,226,613)	(197,880,056)	10.19%	(20,159,581)	P-3
FAS 109 Incremental - NetPlt	0	-	0	10.19%	0	P-3
Total	(418,390,712)	(23,621,441)	(442,012,153)		(48,539,084)	

Property Taxes

Description	Allocator	Texas Jurisdiction	Allocation to Transmission	Transmission	
AZ Property Taxes	D1PROD	(7,627)	0.00%	-	P-2
AZ Property Taxes	D2TRAN	5,447,616	100.00%	5,447,616	P-2
NM Property Taxes	D1PROD	-	0.00%	-	P-2
NM Property Taxes	LABOR	152,377	21.21%	32,323	P-2, P-10
NM Property Taxes	PRODPLT	1,884,746	0.00%	-	P-2
NM Property Taxes	D2TRAN	329,862	100.00%	329,862	P-2
TX Property Taxes	DISTPLT	4,847,407	0.00%	-	P-2
TX Property Taxes	LABOR	690,968	21.21%	146,573	P-2, P-10
TX Property Taxes	PRODPLT	8,546,564	0.00%	-	P-2
TX Property Taxes	D2TRAN	1,495,792	100.00%	1,495,792	P-2
	Total	23,387,704		7,452,167	

LABOR ALLOCATOR (Schedule P-10)

Production O&M	13,608,521	33.74%
Transmission O&M	8,556,532	21.21%
Distribution O&M	11,130,170	27.59%
Customer O&M	7,041,567	17.46%
	40,336,789	100.00%

			Non-Peaking D1PROD	Peaking D2PROD
1	Texas Retail Jurisdictional Production Allocation Factor (TRAF)		81.0545%	81.0178%

			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	
	TXRT22	Irrigation Service	3,840,029	
	TXRT24	General Service	1,450,801,644	4,599,057
	TXRT25	Large Power Service	611,107,048	1,412,387
	TXRT26	Petroleum Refining Service	314,641,719	484,800
	TXRT28	Private Area Lighting Service	26,829,319	
	TXRT30	Electric Furnace Rate	21,568,632	62,983
	TXRT31	Military Reservation Service	297,329,301	612,000
	TXRT34	Cotton Gin Service	1,596,380	5,904
	TXRT41	City and County Service	193,240,554	618,580
			5,934,580,280	7,885,711

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

			Non-Peaking D1PROD	Peaking D2PROD
4	Rate Class Allocation Factors ($ALLOC_{RC\text{-}CLASS}$)			
	TXRT01	Residential Service	54.831400%	55.546443%
	TXRT02	Small General Service	4.696700%	4.727409%
	TXRT07	Outdoor Recreational Lighting Service	0.030900%	0.000000%
	TXRT08	Street Lighting	0.302800%	0.000000%
	TXRT09	Traffic Signals	0.017400%	0.012914%
	TXRT11TOU	Municipal Pumping Service - TOU	1.616600%	1.585012%
	TXRT15	Electrolytic Refining Service	0.517600%	0.515046%
	TXRTWH	Water Heating Service	0.043000%	0.025363%
	TXRT22	Irrigation Service	0.094900%	0.096392%
	TXRT24	General Service	21.004100%	21.015020%
	TXRT25	Large Power Service	6.900300%	6.833125%
	TXRT26	Petroleum Refining Service	2.810300%	2.754233%
	TXRT28	Private Area Lighting Service	0.225300%	0.000000%
	TXRT30	Electric Furnace Rate	0.339600%	0.341300%
	TXRT31	Military Reservation Service	3.497700%	3.476907%
	TXRT34	Cotton Gin Service	0.013400%	0.001132%
	TXRT41	City and County Service	3.058000%	3.069704%
			100.000000%	100.000000%

The following files are not convertible:

Exhibit AH-1R - Revised A-01 and B-01.1.xlsx
Exhibit AH-2R - JCOS Summary.xlsx
Exhibit AH-3R - CCOS Summary.xlsx
Exhibit AH-4R - DCRF Baseline.xlsx
Exhibit AH-5R - TCRF Baseline.xlsx
Exhibit AH-6R - GCRR Baseline.xlsx