Filing Receipt

Received - 2021-10-22 12:32:58 PM
Control Number - 52195
ItemNumber - 270

SOAH DOCKET NO. 473-21-2606
PUC DOCKET NO. 52195

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

DIRECT TESTIMONY OF

RAYMOND J. STANLEY

ON BEHALF OF

VINTON STEEL, LLC

OCTOBER 22, 2021

DIRECT TESTIMONY OF

RAYMOND J. STANLEY

TABLE OF CONTENTS

CONTENTS

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Raymond J. Stanley, R. J. Stanley and Associates, Inc., 366 Pine Valley Dr., Fairview, Texas 75069.

Q. WHAT IS YOUR POSITION WITH R. J. STANLEY AND ASSOCIATES, INC.?

A. I am President of the firm. In this capacity, I am responsible for the direction and supervision of all consulting activities, including cost-of-service, rate design, and load research projects for electric and gas utilities. Also, I am responsible for the presentation of expert testimony in formal rate proceedings.

Q. WILL YOU PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND TRAINING?

A. I graduated from Newark College of Engineering with a Bachelor of Science Degree in Electrical Engineering in 1967. In 1967 and 1968, I took several graduate courses in mathematics at Brooklyn Polytechnic Institute. After leaving the U.S. Army in 1970, I attended Long Island University and graduated in 1973 with a Master's Degree in Management Science and Engineering. I have attended various utility-sponsored conferences, schools, seminars, and meetings involving cost analysis, engineering, and economic discussions.

Q. WHAT IS YOUR PROFESSIONAL BACKGROUND?

A. Upon graduation from Newark College of Engineering in 1967, I worked for the Long Island Lighting Company for approximately a year and a half as an Engineer in the

Distribution Engineering Department. In that capacity, I participated in various efforts to design computer systems to help in analyzing the impact of electric system interruptions on total system reliability.

Late in 1968, I was inducted into the Armed Services where I was assigned to the Special Missions Group of the Army Material Command. In that position, I assisted civilian engineers and scientists to develop electronic gear used to gather military intelligence in combat zones. After my honorable discharge in 1970, I returned to Long Island Lighting Company and worked for approximately three more years in the Distribution Engineering Department. In that position, I was responsible for various cost-benefit studies pertaining to the purchase and refurbishing of equipment utilized on the electric distribution system. I assisted in the preparation of comparative engineering economic studies involving the relative service reliability of new equipment. I was also involved in the development of various contractual arrangements with outside contractors.

I joined Gilbert Management Consultants in January of 1974 as an Engineer involved in rendering consulting services in the rate and regulatory area to public utility companies. In September of 1978, I opened the Company's first regional office (in Austin, Texas) specializing in rate and regulatory affairs. In March of 1980, I left Gilbert Management Consultants and joined Ebasco Business Consulting Company as Manager of Client Services. In October of 1981, I was elected by the Board of Directors to the position of Regional Vice President of the Dallas Regional Office. In April of 1983, I established my current firm. R. J. Stanley & Associates, Inc. provides rate and regulatory consulting services to clients in various sectors. Prior clients have included investor-owned utilities, electric cooperatives, municipal utilities, industrial customers, and consumer groups.

Q. HAVE YOU RECEIVED A LICENSE AS A REGISTERED PROFESSIONAL ENGINEER?

A. Yes, I have received a license as a Registered Professional Engineer in two States. I was licensed, by examination, in the Commonwealth of Pennsylvania–Registration No. 21519-E and in the State of Texas–Registration No. 45356.

Q. IN THE COURSE OF YOUR EMPLOYMENT BY LONG ISLAND LIGHTING COMPANY, GILBERT MANAGEMENT CONSULTANTS, EBASCO BUSINESS CONSULTING COMPANY, AND R. J. STANLEY AND ASSOCIATES, INC., HAVE YOU PARTICIPATED IN STUDIES IN CONNECTION WITH MATTERS WHICH HAVE COME BEFORE REGULATORY COMMISSIONS?

A. Yes. I have prepared or assisted in the preparation of cost-of-service studies and rate studies presented in proceedings before the Federal Energy Regulatory Commission, South Carolina Public Service Commission, Wisconsin Public Service Commission, Massachusetts Department of Public Utilities, Arizona Corporation Commission, Arkansas Public Service Commission, Louisiana Public Service Commission, New Mexico Public Utility Commission, Public Utility Commission of Texas, El Paso Public Utility Board, and several State and Federal District Courts. I assisted in the preparation of service reliability studies presented by the Long Island Lighting Company to the New York Public Service Commission. In addition, I prepared and presented comparative rate of return studies in an antitrust proceeding before the United States District Court. I have presented cost of service and rate design testimony in several state district courts.

Q. DID YOU SPONSOR COST-OF-SERVICE OR RATE-RELATED STUDIES AS AN EXPERT WITNESS IN ANY OF THESE PROCEEDINGS?

A. Yes. I was an expert witness in proceedings before the Massachusetts Department of Public Utilities, Wisconsin Public Service Commission, Public Utility Commission of Texas, Arizona Corporation Commission, Arkansas Public Service Commission, Louisiana Public Service Commission, New Mexico Public Utility Commission, El Paso Public Utility Board, Federal Energy Regulatory Commission, State District Court of Missouri, State District Court of Louisiana, State District Court of Oklahoma, and the Federal District Court. Most of my testimony pertained to cost-of-service or rate design issues.

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

A. I am presenting testimony on behalf of Vinton Steel, LLC. The steel mill is served under EPE's Rate 30 and EPE's Rate 38 and specializes in the production of rebar for the commercial and industrial construction industry. In addition, Vinton Steel produces materials used in the mining industry.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS CASE?

A. In my testimony, I will address the distribution of the proposed revenue increase to the various classes of service; the design of the proposed interruptible rate; and the demand and energy loss factors used by EPE.

II. SUMMARY OF RECOMMENDATIONS

Q. PLEASE BRIEFLY SUMMARIZE YOUR RECOMMENDATIONS IN THIS CASE.

A. In my direct testimony, I make the following recommendations:

- All firm classes of service should be limited to a base rate increase of 1.5 times the system average percentage increase that may be allowed by this Commission.
- The final Rate 38, Noticed Interruptible Power Service, should be designed by applying the same overall base rate percentage change that may be approved to both the demand and energy components of the rate.
- EPE should be ordered to explain and justify why the proposed energy related loss factors are greater than demand related loss factors.

III. DISTRIBUTION OF THE PROPOSED REVENUE REQUIREMENT

Q. WHAT ARE EPE'S STATED GOALS IN PROPOSING THEIR DISTRIBUTION OF ITS CLAIMED REVENUE REQUIREMENT?

A. EPE states that it is attempting to minimize subsidies between rate classes, send proper price signals, encourage energy conservation, reduce contributions to EPE's system peak demand, and provide stable rates for customers. EPE believes that it has distributed the overall jurisdictional revenue requirement to the classes so that the relative rate of return produced by each class will reach 1.0. EPE states that it has moderated the increases to some classes in accordance with gradualism limitations and in an attempt to reduce rate shock.

7

Q. WHAT DO YOU MEAN BY THE TERM "RELATIVE RATE OF RETURN"?

A. Based on the cost allocation study presented by EPE, each class of customer will produce a measure of profitability, or rate of return. If all classes produce the same, or equalized, rate of return, the study will indicate that the relative rates of return are at unity. In this case, EPE is requesting a jurisdictional rate of return of 7.985%. If each class produced the same rate of return (i.e., 7.985%), unity would be achieved and the relative rate of return for each class would be 1.0.

Q. DO YOU GENERALLY AGREE WITH THE RATE DESIGN GOALS LISTED BY EPE IN THIS CASE?

A. Yes, though I disagree with EPE's recommendations as to how those goals should be achieved. I agree that it is important to set electric rates that eliminate, to the extent reasonably possible, subsidies between classes of service. If the proper cost-based price signals are sent to customers, more stable rates will result from the standpoint of both the customer and the utility, economic efficiency can be achieved, and energy conservation follows as a result of rational customer responses to the correct price signals.

I also agree that moving all classes to a unity relative rate of return in a single rate proceeding can cause "rate shock." This Commission has applied the principal of "gradualism" when setting class rates in a given rate proceeding, allowing rate classes to move significantly toward, rather than immediately to, fully cost-based rates for the purpose of avoiding undue economic hardship.

Q. HAS EPE ADOPTED THE PRINCIPAL OF GRADUALISM IN THIS AND PRIOR RATE APPLICATIONS?

A. Yes. Mr. James Schichtl discusses EPE's efforts in past cases to move classes towards cost. He details the Company's revenue allocation proposals in EPE's Docket Nos. 37690, 40094, and 44941. He goes on to state that EPE proposes to moderate the cost-based revenue requirements for certain rate classes, including "Residential, Water Heating, Small General Service, General Service, and City/County rate groups." (Schichtl Direct, page 38, line 30-31).

Q. BRIEFLY DESCRIBE HOW EPE PROPOSES TO MOVE CLASSES TOWARD RATE PARITY IN THIS CASE, WITH MODERATION?

A. EPE proposes to set "caps" and "floors" for certain rate classes in order to moderate the proposed base rate increases and decreases. Specifically, EPE proposes to cap the base rate increase for the Residential and Water Heating classes to 1.5 times the overall system percentage increase and set a floor of 50% of the decrease indicated by their cost-of-service study to the Small General Service, General Service, and City and County Service classes. Since the overall proposed system base rate increase for the Texas jurisdiction is 7.79%, the cap of 1.5 times the average suggests that no class should receive a base rate increase more than 11.69%.

Q. HAS EPE PROPOSED A BASE RATE INCREASE MORE THAN 11.689% FOR ANY CLASS IN THIS PROCEEDING?

A. Yes. According to Exhibit A, page 2 of 4 of the rate filing package, there are 17 retail customer classes listed. Of those, EPE proposes to increase base rates more than 11.69% for 9 of those classes. At the same time, EPE is proposing to reduce the base rates for 5 of the 17 classes of service.

Q. WHAT ARE ALL OF THE CLASS PERCENTAGE BASE RATE INCREASES PROPOSED IN THIS CASE BY EPE?

A. The proposed base increases are shown below in Table 1. The data showing the proposed change in base revenue and the average percentage change for this table was taken from Exhibit A, page 2 of 4 contained in the rate filing package. I have added the ratio to the jurisdictional total which reflects the multiplier that EPE is proposing for each class of service.

TABLE 1

Texas Retail Rate Classes	Proposed Change in Base Revenue ($)	Avg. Change in Base Charges (%)	Ratio to Jurisdictional Total
Schedule 01-Residential	38,536,221	14.08	1.81
Schedule 02-Sm General Serv.	(809,757)	(2.43)	(0.31)
Schedule 07-Outdoor Rec. Light.	167,566	36.19	4.65
Schedule 08-Govt Street Lighting	(897,779)	(22.19)	(2.85)
Schedule 09-Traffic Signals	5,103	5.36	0.69
Schedule 11-TOU Muni Pumping	321,059	3.18	0.41
Schedule 15-Electrolytic Refining	456,409	24.94	3.20
Schedule 22-Irrigation	147,853	34.92	4.48
Schedule 24-General Service	(2,515,587)	(2.01)	(0.26)
Schedule 25-Lge Power Service	2,139,407	5.95	0.76
Schedule 26-Petroleum Refinery	2,260,115	20.61	2.65
Schedule 28-Area Lighting	(229,631)	(7.83)	(1.01)
Schedule 30-Electric Furnace	347,772	29.18	3.75
Schedule 31-Military Reservation	2,091,786	16.08	2.06
Schedule 34-Cotton Gin	49,244	37.03	4.75
Schedule 41- City/County Service	(635,733)	(3.32)	(0.43)
Rider Water Heating	69,755	14.70	1.89
Rate 38-Noticed Interruptible	324,235	7.77	1.00
Texas Jurisdictional Service	41,828,036	7.79	1.00

As shown above, EPE's rate proposal would result in some classes receiving base rate percentage increases that are much more than the 1.5 times multiplier that EPE has as a stated goal. Rate 30, for example, which is the tariff used to bill the firm power consumed at Vinton Steel, would receive a base rate increase that is 3.75 times the system average!

Q. YOU MENTIONED EARLIER THAT EPE DETAILED ITS PROPOSALS TO MODERATE BASE RATE CHANGES IN PRIOR CASES. WHAT WERE THE PROPOSED "MULTIPIERS" OR CAPS IN THOSE CASES?

A. According to the testimony of Mr. Schichtl, EPE proposed to limit rate class increases to a 2.0 times multiplier in Docket No. 37690; a limit of eight percent base rate increase for most firm rate classes in Docket No. 40094; and in Docket No. 44941, EPE proposed a limit using a multiplier of 2.0 times the system average. As stated above, Rate 30, for example, would receive a base rate increase of 29.18% which equates to a multiplier of that is 3.75 times the system average. The increase proposed for Rate 30 not only violates gradualism movement in this case, but it would produce increases greater than the class limitations advocated by EPE in its prior cases.

Q. DO YOU BELIEVE THAT EPE'S PROPOSED RATES IN THIS CASE WILL LEAD TO THE ACCOMPLISHMENT OF EPE'S STATED GOAL OF ACHIEVING COST-BASED RATE PARITY FOR ALL CLASSES IN THIS CASE?

A. No. Due to the method of capping and setting floors for the rate increases and decreases proposed in this case, the resulting relative rates of return by class of service do not reach unity. In the response to FMI 1-14, attached as Exhibit RJS-1, EPE provides the resulting rates of return and relative rates of return for each class under the proposed rate schedules and including the "capped" and "floored" revenues. According to that response, Rate 30, Electric Furnace, would produce a rate of return of 8.717%, and a relative rate of return of

1.092. Therefore, EPE's proposed revenue allocation to Rate 30 assigns a base rate increase that is 3.75 times the system average <u>and</u> produces a rate of return that is over 9% greater than the jurisdictional average.

Q. DO YOU BELIEVE THAT THE CLASSES SELECTED FOR THE CAP BY EPE ARE IN FACT THE ONLY ONES THAT ARE AT RISK OF RATE SHOCK IN THIS PROCEEDING ABSENT THE APPLICATION OF GRADUALISM?

A. No, I do not. All rate classes are susceptible to the risk of rate shock, and the distribution of the final revenue increase should take that fact into account. The proposed increase for Rate 30 is a prime example of rate shock risk for classes other than those few selected by EPE for moderation through application of gradualism.

Q. WHAT DO YOU RECOMMEND WITH REGARDS TO THE DISTRIBUTION OF FINAL REVENUE INCREASE THAT MAY BE ALLOWED IN THIS CASE?

A. If any revenue increase is approved in this case, no class should incur a percentage base rate revenue increase that is more than 1.5 times the jurisdictional average that may be allowed by the Commission in this case.

IV. <u>NOTICED INTERRUPTIBLE POWER SERVICE RATE DESIGN</u>

Q. BRIEFLY DESCRIBE THE NOTICED INTERRUPTIBLE POWER SERVICE RATE PROPOSED BY EPE IN THIS CASE.

A. The rate is available to customers with connected capacity of 1 MW or more, with a minimum level of firm demand of 600 kW. EPE can make intentional interruptions at any time at the Company's sole discretion.

The rate has been in effect for years but has been closed to new customers. In this proceeding, EPE proposes to expand its availability to new customers and extend the total capacity to 75 MW from the existing 47 MW.

Q. DO YOU AGREE THAT THE NOTICED INTERRUPTIBLE POWER SERVICE RATE SHOULD BE EXPANDED?

A. Absolutely. In previous applications to change rates filed by EPE, in which we have participated, we have promoted the value of the interruptible service rate, pointing out that curtailable load is a valuable resource that EPE can depend upon to improve its service reliability and reduce costs for all firm power customers. I applaud EPE for proposing to expand the rate and attempting to make more capacity available on the power system.

Q. YOU MENTIONED THAT CURTAILABLE LOAD IS A VALUABLE RESOURCE THAT WILL IMPROVE SERVICE RELIABILITY FOR ALL FIRM CUSTOMERS. PLEASE EXPLAIN.

A. Regarding system reliability, look at Exhibit RJS-2, which is a copy of the response to FMI 1-3, Attachment 1. It shows the loads and resources on the EPE system for the years 2021-2030, using the most updated load forecast. Notice that line 1.9 of that Exhibit contains the amount of interruptible load on the EPE system and is counted as a generation resource. Also, notice on line 8.0 that EPE uses a 15% planning reserve margin over its 10-year planning horizon. The chart indicates that EPE will not have enough generating capacity to cover its own 15% planning reserve margin, showing a deficit of 64 MW in 2021 growing to a shortfall of 77 MW in the year 2030. If interruptible capacity were not available, the deficit in 2021 would be 120 MW and increase to 133 MW in the year 2030. Stated another way, if the interruptible capacity were not available this year, the reserve margin on the EPE system would be only 9.3%, well below the desired 15% required for planning purposes.

Q. HOW DID EPE TREAT THE REVENUES AND EXPENSES RELATED TO RATE 38 - NOTICED INTERRUPTIBLE POWER SERVICE?

A. During the test year, the customers taking power under Rate 38 produced $4,174,343 in base (non-fuel) revenue. As is customary with respect to utility interruptible service offerings, there is no separate class of service for Rate 38 in the EPE cost of service study. Instead, all revenue from Rate 38 is allocated back to all firm customers as a revenue credit. EPE's non-firm revenue allocation method is based on the principle that all firm customers contribute to the plant investments and expenses on the system and all firm customers should therefore be credited with the revenue from non-firm customers as an offset to those costs.

Q. HOW WAS RATE 38 DESIGNED IN THIS RATE APPLICATION?

A. First, the proposed rate level for the rate was set by EPE to produce test year revenues of $4,498,580, for an "average" increase of $324,237, or 7.77%. The percent increase was set equal to the overall jurisdictional base rate increase that is requested by EPE in this case. The energy charge for Rate 38 was set at the same level as the off-peak energy charge that is contained in EPE's proposed Large Power Service, Rate No. 25. The proposed demand charge for Rate 38 is based upon an estimate of avoided incremental capacity cost and set to a level to produce the desired test year revenues.

Q. WAS A RATE OF RETURN DEVELOPED FOR THE CUSTOMERS IN RATE 38?

A. No. It is important to understand that, because interruptible service is not a separate class in the cost allocation study, no rate base items are allocated to interruptible service. No operating expenses are allocated and therefore, no annual return, or rate of return is established for Noticed Interruptible Power Service. Furthermore, no relative rate of return analysis is possible, nor would there be any reason to attempt it.

No rate base or return on investment is assigned to interruptible service because utilities do not plan or build plant for the purpose of serving non-firm load. In EPE's case, customers taking power under the interruptible service rate can be curtailed up to 400 hours in any calendar year. Interruptions can be ordered by EPE at any time and from time to time at EPE's sole discretion. Therefore, EPE does not have to include its interruptible load in its long-term demand forecasts and does not have to include curtailable load in its generation planning. Exhibit RJS-3 contains the response to FMI 1-7. The response states, in part, that "interruptible load is a dispatchable capacity resource in that EPE can call on it as needed and that is being relied upon to serve peak load." In addition, the response states that "it is included in the total resources to meet the peak load and planning reserve margin." EPE considers interruptible load as a capacity resource in its planning process. The added capacity provided by interruptible customers can delay and/or minimize future expansion.

EPE can count on the interruptible load as a resource in an emergency, or to maintain its reserve margin to make sure firm customers are provided reliable power and energy. In addition, to take service under the Noticed Interruptible Power Service rate, the customer must install all necessary communication, relay, and breaker equipment at the customer's expense.

Q. YOU MENTIONED THAT EPE DESIGNED RATE 38 BY SETTING THE ENERGY CHARGE EQUAL TO THE OFF-PEAK ENERGY CHARGE CONTAINED IN THE PROPOSED RATE 25. IS THAT APPROPRIATE?

A. No. It is illogical to select a unit cost from one rate class of service in the cost allocation study and inject that unit cost in the rate design of another class of service. In this case, EPE developed the off-peak energy charge for Large Power Service, Rate 25, and assumed that energy unit charge ($/kWh) should be equal to the energy rate that is contained in the Noticed Interruptible Power Service, Rate 38.

The two types of power service are completely different. Rate 25 is a firm power rate and subject to the allocation of the system-wide customer, demand, and energy cost components. On the other hand, because of the unique nature of interruptible power service, it is not included as a separate class of customers in the cost allocation study. Since interruptible customers are the first to be curtailed during extreme peak system loading or under any other condition that EPE deems necessary, the electrical power delivered to Rate 38 customers is a much lower quality of service as compared to power served under EPE's other firm rates.

Q. DOES EPE PROPOSE TO CHARGE THE SAME OFF-PEAK ENERGY RATE ($/kWh) TO ALL FIRM POWER CLASSES?

A. No. For example, the proposed off-peak energy charge for Rate 25 is $0.00119/kWh at the transmission level of delivery. The proposed off-peak energy charge in the alternative time-of-day (TOD) Rate 24, General Service Rate, at the transmission level of delivery, is $0.04089/kWh (summer) and $0.02790/kWh (non-summer).

Q. WOULD YOU EXPECT THAT THE OFF-PEAK ENERGY CHARGES BETWEEN RATE 25 AND RATE 24 (TOD) TO BE THE SAME?

A. Not at all. The reason there are separate classes of service is because end-use customers have different usage characteristics such as monthly load factors, peak capacity requirements, delivery voltages, phasing requirements and metering. In addition, joint costs are spread to the firm power classes using multiple customer, demand, and energy allocation factors that vary from class to class. With all of these differences, there is no reason that the charges designed for one class of service should be imposed on another class.

Q. BESIDES THE FACT THAT RATE 25 IS FIRM SERVICE WHILE RATE 38 IS CURTAILABLE, ARE THERE OTHER DIFFERENCES BETWEEN THE TWO RATES?

A. Yes. EPE has assigned two different levels of base rate increases to the classes. Rate 25 was allocated a base rate percentage increase that is less than the system average. As shown in Table 1 above, Rate 25 would be charged a base rate increase of 5.95% under the proposed rates, which represents a ratio to the jurisdictional total of 0.76. At the same time, Rate 38 was assigned the jurisdictional system average base rate increase of 7.77%.

Also, to take power under Rate 38, the end-use customer must purchase a portion of its energy needs under one of EPE's firm rates. As an example, Vinton Steel purchases some of its power under Rate 30, which is a firm rate schedule that requires a 5 MW minimum load. Vinton's firm portion is subject to the full demand and energy charges as prescribed in Rate 30.

Q. YOU STATED THAT EPE ASSIGNED THE SYSTEM AVERAGE BASE RATE PERCENTAGE INCREASE IN DESIGNING RATE 38. DO YOU AGREE WITH THAT PROCEDURE?

A. I do not think it is unreasonable. While it makes no sense to use charges from another rate (i.e., Rate 25) as a basis for the charges in Rate 38, it is very important to provide some stability in the rate design process from rate change to rate change. This is especially true in this case since EPE claims to want to enhance its interruptible service and bring on more curtailable load. For a large commercial or industrial customer to agree to the terms and conditions of a non-firm power service, including the risk of losing power at the sole discretion of the Utility, it would want to believe that the rate will be available into the foreseeable future and that the price paid for that service will be fair and not subject to wide swings between the demand and energy components.

Q. HOW MANY CUSTOMERS DOES EPE SERVE UNDER RATE 38?

A. There are only 9 customers in the Rate 38 class.

Q. WHAT ARE YOUR CONCERNS WITH EPE'S PROPOSED DEMAND AND ENERGY CHARGES FOR THE INTERRUPTIBLE POWER SERVICE RATE?

A. There are basically two rate components in the Noticed Interruptible Power Service Rate -- demand ($/kW) and energy ($/kWh). In this proceeding, EPE proposes to nearly double the unit demand component of the rate while recommending a very large decrease in the energy component. Table 2 below shows the present and proposed demand and energy unit charges for Noticed Interruptible Power Service (Transmission Voltage).

TABLE 2

Rate Component	Present Charge	Proposed Charge	Change	Percent Change
Demand	$2.16/kW	$4.14/kW	$1.98/kW	91.7%
Energy	$0.00479/kWh	$0.00119/kWh	($0.0036/kWh)	(75.2%)

As can be seen, EPE wants to raise the demand charge by over 91%, while reducing the energy charge by more than 75%! On "average," the proposed rate will produce an annual base rate increase of $324,237. However, due to the disparity in the customers' individual load factors, some customers would see significant base rate increases while others would realize annual decreases.

Q. ON WHAT DO YOU BASE YOUR CONCLUSION THAT DIFFERENCES IN LOAD FACTORS WOULD RESULT IN LARGE INTRA-CLASS REVENUE SHIFTS AS A RESULT OF EPE'S PROPOSED RATE DESIGN?

A. Attached as Exhibit RJS-4 is a copy of EPE's response to VS 1-14. Without actually naming the individual customers, EPE lists the average load factor for each Noticed Interruptible customer and the base rate increase or decrease under the proposed interruptible rate. As shown, some of the Rate 38 customers would receive base rate increases that are much higher than the average for the rate (i.e., 7.77%), while some other customers would actually receive a base rate decrease! In the extreme case, Customer "C" would see a base rate <u>increase</u> of 19.8% while Customer "A" would realize a 9.6% <u>decrease</u>.

Not only would the proposed design for Rate 38 cause a significant shift in base rate revenues paid by individual customers, in violation of EPE's efforts to avoid the potential for rate shock, it also undercuts EPE's goal of growing participation in Rate 38.

Q. PLEASE EXPLAIN YOUR CONCERN THAT EPE'S PROPOSAL TO EFFECTUATE A LARGE SHIFT IN RATE 38 INTRA-CLASS REVENUE ASSIGNMENT WILL IMPEDE EPE'S GOAL OF PROMOTING GREATER RATE 38 PARTICIPATION?

A. EPE has stated that it intends to reopen and expand Notice Interruptible Power Service to secure additional resources to meet EPE's peak loads in the future. As discussed earlier in this testimony, interruptible customers provide a valuable resource that benefits all firm customers and is a key component in maintaining system reliability. Consequently, EPE wants to attract more interruptible load. Changing the rate design in the fashion proposed by EPE in this case could offer a disincentive for new customers to apply for the rate and could also cause current Rate 38 customers adversely impacted by the large intra-class revenue shift proposed by EPE to terminate their participation in Rate 38.

Q. EPE, THROUGH MR. CARRASCO'S TESTIMONY, STATES THAT RATE 38 CUSTOMERS WILL NOT LEAVE THE INTERRUPTIBLE SERVICE BECAUSE THE RATE IS LOWER THAN "WHAT THEY WOULD PAY, ON AVERAGE, FOR FULL FIRM SERVICE." DO YOU AGREE?

A. No. Mr. Carrasco fails to take into account internal costs and operational risks associated with taking service under Rate 38. Purchasing power under Rate 38 could be rendered economically unattractive at times, relative to firm service. Besides the costs incurred by the interruptible customer to install the needed communication and breaker equipment, mentioned earlier, and the substantial penalties that could be incurred for non-compliance that are described below, there are other internal costs that result from halting production when EPE orders a curtailment. Depending upon the time and duration of an interruption, the mill's production schedule can be seriously delayed, product waste can result, and employees can be idled for extended periods at substantial cost.

Q. EPE CAN INTERRUPT RATE 38 CUSTOMERS AT ANY TIME. IN THE EVENT THAT THE CUSTOMER CHOOSES NOT TO CURTAIL ITS LOAD, AS ORDERED, WHAT PENALTIES CAN BE CHARGED TO THE RATE 38 CUSTOMER FOR NON-COMPLIANCE?

A. The rate contains a "Non-Compliance" section that allows EPE to impose substantial monetary penalties if the customer does not reduce its demand on the system. As discussed in the testimony of Mr. Carrasco, page 11, lines 11-26, EPE made a revenue adjustment of $1.2 million to account for the payment by one customer that did not meet its obligation to curtail under the terms and conditions of Rate 38.

Q. HAVE THERE BEEN OTHER OCCASIONS WHEN EPE IMPOSED PENALTIES ON INTERRUPTIBLE CUSTOMERS FOR NON-COMPLIANCE?

A. Yes. Exhibit RJS-5 contains the response to CEP 9-38. It shows that amount of penalties that have been charged to interruptible customers by EPE in recent years. As shown, penalties that have been imposed have exceeded $200,000 each year from 2016-2018.

Q. YOU STATED EARLIER THAT EPE CLAIMS INTERRUPTIBLE CUSTOMERS WILL NOT LEAVE THE RATE BECAUSE THE RATE IS LOWER THAN FIRM SERVICE. HAS EPE MADE AN ATTEMPT TO EVALUATE THE IMPACT OF PRICE CHANGES ON RATE 38 CUSTOMERS?

A. No. The response to VS 1-6, contained in Exhibit RJS-6 shows that while EPE has analyzed the effects of price elasticity for several classes of service, it has not determined how interruptible customer would react to a change in base rate prices.

Q. WHAT DO YOU RECOMMEND TO THIS COMMISSION REGARDING THE DESIGN OF THE INTERRUPTIBLE RATE?

A. Without the allocation or assignment of rate base and expenses, it is reasonable to assign Noticed Interruptible Power Service a percentage increase that is equal to the system average base rate increase that is approved by this Commission. However, as shown earlier, in order to reduce or eliminate intra-class disparities, the same base rate percentage change that is allowed by the Commission should be applied equally to the demand and energy unit charges in the rate.

V. DEMAND AND ENERGY LOSS FACTORS

Q. HAVE YOU REVIEWED THE LOSS FACTORS SUBITTED BY EPE IN THIS CASE?

A. Yes.

Q. DO YOU HAVE ANY CONCERNS WITH THE FACTORS THAT EPE HAS USED IN ITS COST ALLOCATION AND RATE DESIGN?

A. Yes. The loss factors for the transmission level indicate that the loss multipliers to account for annual energy related losses are greater than those for the peak demand losses. In fact, the opposite should be true. The large majority of the peak load related losses are a direct function of the square of the line current flow at the time of maximum system demand and should exceed the average annual energy losses incurred over the course of the year.

Q. WHAT IS THE PURPOSE FOR DEVELOPING DEMAND AND ENERGY LOSS FACTORS IN A COST ALLOCATION STUDY?

A. To allocate demand and energy costs equitably to the various classes of service on an electric power system, all of the customer sales volumes, both peak demand and annual energy, must be adjusted through the use of demand and energy loss factors to one common voltage level, usually the generation level. That way, customers taking power and energy at the various voltage levels available to customers are only responsible for the losses they cause the system to incur. For example, if demand and energy allocation factors of all classes of service are adjusted to a common level, customers that take power at the transmission levels are not allocated costs associated with losses that are incurred on the primary or secondary distribution levels.

Q. BRIEFLY DESCRIBE HOW THE LOSS FACTORS WERE DEVELOPED BY EPE IN THIS CASE.

A. The loss factors filed in this case were developed using data from the year 2017 and EPE estimated the losses in two steps. First, the transmission loss factors for the 345kV, 115kV, and 69kV voltage levels were developed using EPE's power flow studies. Second, an outside consultant, Management Application Consulting, Inc. (MAC) prepared line loss estimates for the distribution primary and distribution secondary systems. The loss data from those two steps were combined to derive demand and energy loss factors from the generation level down through the secondary voltage level of service.

Q. WHY ARE YOU CONCERNED BY THE FACT THAT EPE FILED ENERGY LOSS FACTORS THAT ARE GREATER THAN THE DEMAND LOSS FACTORS

FOR THE TRANSMISSION VOLTAGES?

A. As stated earlier, the large majority of demand and energy losses on a power system are a direct function of the square of the current passing through the electrical devices times the resistance in those devices (I^2R). The loss study prepared by MAC for this case was filed in Schedule O-6.3.

At the time of the system peak, the overall current is at its highest level. Since the power losses vary <u>exponentially</u> with the electrical current, one would expect that the percent loss at the time of the highest system demand would be significantly greater than the average percent energy loss throughout the year. Looking at EPE's loss study, the expected demand/energy relationship does hold up in the factors filed for the primary and secondary systems, but that relationship does not follow through for the higher transmission voltage levels.

Q. ON PAGES 48-50 OF THE LOSS STUDY CONTAINED IN SCHEDULE O-6.3 OF THE RATE FILING PACKAGE, THERE IS A DISCUSSION OF THE "HOEBEL COEFFICIENT". PLEASE DESCRIBE ITS RELEVANCE HERE.

A. The Hoebel Coefficient is a mathematical tool used in many loss analyses to estimate the amount of average energy losses on an electrical power system, based upon the demand losses that are determined on the system. As stated on page 49 of Schedule O-6.3, "peak demand losses can readily be calculated given equipment resistance and approximate loading. Energy losses, however, are much more difficult to determine given their time-varying nature." The Hoebel constant is a factor that is always less than 1.0, usually between 0.7 and 0.9. Hoebel derived a formula to convert the estimate of demand losses

24

to an estimate of the average energy losses by multiplying peak load losses times the Hoebel constant and the system load factor (the formula is shown on page 50 of the Loss Study). Every element in the formula that is multiplied by the peak demand losses is less than 1.0. In other words, the estimate of the average energy losses must be less than the estimate of the associated demand losses. The loss analysis goes on to conclude that "Loss studies use this equation to calculate energy losses at each major voltage level in the analysis." (Schedule O-6.3. page 50 of 50).

Q. WHAT DO YOU RECOMMEND REGARDING EPE'S LOSS ANALYSIS IN THIS CASE?

A. This Commission should order EPE to explain, in detail, why its annual energy loss percentage on the transmission system is greater than the peak demand loss percentage. If a change in the demand and energy loss factors is required, the revised loss factors should be used in the final cost of service study and rate design ordered in this case.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

25

THE STATE OF TEXAS:

COUNTY OF COLLIN:

BEFORE ME, the undersigned authority, on this day personally appeared RAYMOND J. STANLEY, having been duly sworn, upon oath says:

"My name is Raymond J. Stanley. I am legal age and a resident of the State of Texas. The foregoing direct testimony, offered by me is true and correct, and the opinions stated therein are, in my judgment and based upon my professional experience, true and correct."

RAYMOND J. STANLEY

SUBSCRIBED AND SWORN TO BEFORE ME by the said Raymond J. Stanley on this, the 18th day of October, 2021.

Notary Public in and for the State of Texas

LESLIE D HAMPTON
Notary Public
STATE OF TEXAS
My Comm. Exp. 01-28-24
Notary ID # 13233290-1

My Commission Expires:

1/28/2024

EL PASO ELECTRIC COMPANY
2021 TEXAS RATE CASE FILING
SCHEDULE P-1.4: PROPOSED RATE SCHEDULES / EXISTING RATE CLASSES
SPONSOR: ADRIAN HERNANDEZ
PREPARER: ADRIAN HERNANDEZ
FOR THE TEST YEAR ENDED DECEMBER 31, 2020

MODIFIED SCHEDULE P-1.4 FOR FMI 1-14
PAGE 1 OF 4

USES CAPPED/FLOORED REVENUES FROM EXHIBIT MC-4

Line No.	(a) Description	(b) Test Year Total	(c) Rate 01 Residential	(d) Rate 02 Small General Service	(e) Rate 07 Recreational Lighting	(f) Rate 08 Street Lighting	(g) Rate 09 Traffic Signals	(h) Rate 11-TOU TOU Municipal Pumping	(i) Rate 15 Electric Refining	(j) Rate 22 Irrigation Service
1	Operating Revenues									
2	Sales Revenues									
3	Base Revenues									
4	Base [From Exh. MC-4, page 3, line 12 + line 22 + line 23]	$ 574,206,281	$ 312,165,274	$ 32,508,921	$ 630,549	$ 3,148,411	$ 100,810	$ 10,423,164	$ 2,286,269	$ 571,265
5	Non-firm [From Exh. MC-4, page 3, line 24 + line 26]	4,499,479	2,484,953	213,778	-	-	584	71,721	23,306	4,362
6	Fuel Revenues	80,084,706	31,804,571	3,483,415	47,019	461,227	26,554	2,189,127	965,884	49,123
7	Other Sales For Resale Revenues	65,919,767	26,179,155	2,867,288	38,703	379,648	21,857	1,801,926	795,044	40,435
8	Total Sales Revenues	724,710,233	372,633,953	39,073,403	716,272	3,989,286	149,806	14,485,939	4,070,502	665,184
9	Other Operating Revenues	26,921,992	15,767,809	1,404,624	10,805	50,316	3,275	392,937	109,540	25,903
10	Total Operating Revenues (Cost of Service)	$ 751,632,225	$ 388,401,762	$ 40,478,026	$ 727,077	$ 4,039,602	$ 153,081	$ 14,878,876	$ 4,180,042	$ 691,087
11										
12	Operating Expenses									
13	Operation & Maintenance Expenses									
14	Fuel and Purchased Power									
15	Reconcilable	$ 146,004,473	$ 57,983,726	$ 6,350,703	$ 85,722	$ 840,874	$ 48,412	$ 3,991,054	$ 1,760,928	$ 89,558
16	Non-Reconcilable	1,431,449	780,281	67,574	445	4,362	251	23,283	7,452	1,366
17	Other Operation & Maintenance	243,174,207	137,437,679	13,434,934	205,769	1,327,388	48,154	4,333,673	1,031,770	211,112
18	Total Operation & Maintenance Expenses	390,610,129	196,201,685	19,853,212	291,936	2,172,624	96,816	8,348,009	2,800,150	302,035
19	Regulatory Debits and Credits	2,986,404	1,772,719	174,147	2,844	17,422	508	46,930	11,022	2,747
20	Depreciation & Amortization Expense	99,088,920	56,992,584	5,070,296	111,526	549,116	14,614	1,684,139	356,337	102,825
21	Decommissioning and Accretion Expense	111,981	61,402	5,344	32	296	19	1,813	575	107
22	Taxes Other Than Income Taxes	68,511,555	38,094,474	3,447,816	64,286	345,336	11,819	1,232,096	308,184	65,826
23	Current Income Taxes									
24	Federal	19,368,450	11,924,094	989,309	29,945	84,371	1,800	299,499	23,542	23,476
25	State	2,533,565	1,522,123	127,899	3,714	10,806	276	41,131	4,978	2,968
26	Total Current Income Taxes	21,902,015	13,446,217	1,117,209	33,658	95,178	2,077	340,629	28,520	26,444
27	Deferred Income Taxes									
28	Federal	5,721,725	2,499,659	278,983	2,000	34,820	1,790	138,639	62,264	3,397
29	State	995,013	502,358	48,880	753	5,765	226	20,585	7,157	827
30	Total Deferred Income Taxes	6,716,738	3,002,017	327,863	2,753	40,585	2,015	159,224	69,421	4,223
31	Amortization of Investment Tax Credits	(1,505,971)	(820,902)	(71,092)	(468)	(4,589)	(264)	(24,495)	(7,840)	(1,437)
32	Total Operating Expenses	$ 588,421,771	$ 308,750,196	$ 29,924,794	$ 506,567	$ 3,215,969	$ 127,604	$ 11,788,345	$ 3,566,369	$ 502,770
33										
34	Operating Income (Return)	$ 163,210,454	$ 79,651,566	$ 10,553,233	$ 220,510	$ 823,633	$ 25,477	$ 3,090,531	$ 613,673	$ 188,317

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

SCHEDULEL P-1.4
PAGE 1 OF 4

EL PASO ELECTRIC COMPANY
2021 TEXAS RATE CASE FILING
SCHEDULE P-1.4: PROPOSED RATE SCHEDULES / EXISTING RATE CLASSES
SPONSOR: ADRIAN HERNANDEZ
PREPARER: ADRIAN HERNANDEZ
FOR THE TEST YEAR ENDED DECEMBER 31, 2020

USES CAPPED/FLOORED REVENUES FROM EXHIBIT MC-4

Line No.	(a) Description	(b) Test Year Total	(c) Rate 01 Residential	(d) Rate 02 Small General Service	(e) Rate 07 Recreational Lighting	(f) Rate 08 Street Lighting	(g) Rate 09 Traffic Signals	(h) Rate 11-TOU TOU Municipal Pumping	(i) Rate 15 Electric Refining	(j) Rate 22 Irrigation Service
35	Rate Base									
36	Plant in Service	3,665,210,259	2,103,682,116	183,965,607	4,376,463	20,878,309	525,684	63,065,168	12,883,126	3,881,630
37	Accum Depreciation & Amortization	(1,223,765,542)	(701,537,803)	(61,793,364)	(1,266,613)	(9,296,897)	(180,179)	(20,399,198)	(4,546,797)	(1,251,294)
38	Net Plant In Service	2,441,444,717	1,402,144,313	122,172,243	3,109,850	11,581,412	345,506	42,665,970	8,336,330	2,630,336
39										
40	Additions to Rate Base									
41	CWIP	-	-	-	-	-	-	-	-	-
42	Working Cash	(2,622,625)	(1,480,527)	(144,851)	(2,234)	(14,413)	(523)	(47,056)	(11,203)	(2,278)
43	Fuel Inventory	1,393,806	553,532	60,626	818	8,027	462	38,100	16,810	855
44	Nuclear Fuel	-	-	-	-	-	-	-	-	-
45	Materials & Supplies	48,530,177	27,424,147	2,371,954	67,376	324,604	7,482	880,631	168,997	51,879
46	Prepayments	14,822,703	8,649,512	819,849	14,208	82,157	2,430	240,265	56,417	14,131
47	Coal Reclamation Asset	-	-	-	-	-	-	-	-	-
48	Regulatory Assets	9,523,392	5,469,372	476,560	12,131	45,176	1,348	166,428	32,518	10,260
49	Accumulated Deferred Income Taxes	103,531,111	60,537,165	5,454,207	145,366	601,995	14,949	1,788,596	322,987	109,750
50	Tax Regulatory Assets	12,599,101	7,235,780	630,471	16,048	59,766	1,783	220,178	43,020	13,574
51	Miscellaneous Deferred Debits	3,857,692	2,102,823	182,110	1,200	11,754	675	62,745	20,083	3,680
52	Total Additions to Rate Base	191,635,356	110,491,805	9,850,926	254,914	1,119,067	28,607	3,349,888	649,628	201,851
53										
54	Deductions to Rate Base									
55	Customer Deposits	(5,614,689)	(4,974,188)	(452,540)	(3,496)	(3,175)	(836)	(7,704)	(497)	(2,394)
56	Regulatory Liabilities	-	-	-	-	-	-	-	-	-
57	Accumulated Deferred Income Taxes	(336,181,559)	(192,976,465)	(16,864,281)	(406,405)	(1,855,422)	(48,098)	(5,801,325)	(1,175,386)	(357,178)
58	Tax Regulatory Liabilities	(222,349,082)	(127,697,137)	(11,126,562)	(283,223)	(1,054,751)	(31,466)	(3,885,707)	(759,212)	(239,552)
59	Customer Advances - Construction	(25,033,069)	(15,419,265)	(1,303,007)	(84,905)	(344,577)	(2,612)	(508,919)	(15)	(33,156)
60	Total Deductions from Rate Base	(589,178,399)	(341,067,055)	(29,746,389)	(778,028)	(3,257,925)	(83,012)	(10,203,656)	(1,935,111)	(632,280)
61										
62	Total Rate Base	$ 2,043,901,675	$ 1,171,569,063	$ 102,276,780	$ 2,586,736	$ 9,442,555	$ 291,101	$ 35,812,202	$ 7,050,847	$ 2,199,906
63										
64	Rate of Return on Rate Base	7.985%	6.799%	10.318%	8.525%	8.723%	8.752%	8.630%	8.704%	8.560%
65	Relative Rate of Return	1.000	0.851	1.292	1.068	1.092	1.096	1.081	1.090	1.072
66										
67	Total Revenue Requirement	$ 751,632,225	$ 388,401,762	$ 40,478,026	$ 727,077	$ 4,039,602	$ 153,081	$ 14,878,876	$ 4,180,042	$ 691,087
68	Less: Fuel & Other Sales For Resale Revenues	146,004,473	57,983,726	6,350,703	85,722	840,874	48,412	3,991,054	1,760,928	89,558
69	Less: Other Operating Revenues	26,921,992	15,767,809	1,404,624	10,805	50,316	3,275	392,937	109,540	25,903
70	Less: Base Rate Revenues at Present Rates	536,887,982	275,944,218	33,518,015	462,980	4,046,620	95,746	10,168,889	1,851,685	427,460
71	Equals:									
72	Non-Fuel Base Revenue Increase	$ 41,817,778	$ 38,706,009	$ (795,316)	$ 167,569	$ (898,209)	$ 5,648	$ 325,997	$ 457,890	$ 148,167
73	Proposed Percent Increase	7.789%	14.027%	-2.373%	36.194%	-22.197%	5.899%	3.206%	24.728%	34.662%

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

EL PASO ELECTRIC COMPANY
2021 TEXAS RATE CASE FILING
SCHEDULE P-1.4: PROPOSED RATE SCHEDULES / EXISTING RATE CLASSES
SPONSOR: ADRIAN HERNANDEZ
PREPARER: ADRIAN HERNANDEZ
FOR THE TEST YEAR ENDED DECEMBER 31, 2020

USES CAPPED/FLOORED REVENUES FROM EXHIBIT MC-4

Line No.	(a) Description	(b) Rate 24 General Service	(c) Rate 25 Large Power	(d) Rate 26 Petroleum Refinery	(e) Rate 28 Area Lighting	(f) Rate 30 Electric Furnace	(g) Rate 31 Military Reservation	(h) Rate 34 Cotton Gin	(i) Rate 41 City and County	(j) WH Water Heating
1	Operating Revenues									
2	Sales Revenues									
3	Base Revenues									
4	Base [From Exh. MC-4, page 3, line 12 + line 22 + line 23]	$ 122,489,587	$ 38,098,209	$ 13,225,193	$ 2,702,987	$ 1,539,309	$ 15,099,043	$ 182,215	$ 18,490,762	$ 544,311
5	Non-firm [From Exh. MC-4, page 3, line 24 + line 26]	950,805	309,197	124,628	-	15,444	157,329	51	142,174	1,148
6	Fuel Revenues	18,549,194	8,621,024	4,673,421	343,211	2,231,320	4,077,775	20,422	2,475,875	65,544
7	Other Sales For Resale Revenues	15,268,316	7,096,185	3,846,812	282,506	1,836,656	3,356,521	16,809	2,037,956	53,951
8	Total Sales Revenues	157,257,902	54,124,615	21,870,054	3,328,704	5,622,729	22,690,667	219,498	23,146,767	664,953
9	Other Operating Revenues	5,296,351	1,626,997	587,933	32,436	72,452	738,975	3,254	750,793	47,592
10	Total Operating Revenues (Cost of Service)	$ 162,554,254	$ 55,751,612	$ 22,457,987	$ 3,361,140	$ 5,695,181	$ 23,429,642	$ 222,752	$ 23,897,560	$ 712,545
11										
12	Operating Expenses									
13	Operation & Maintenance Expenses									
14	Fuel and Purchased Power									
15	Reconcilable	$ 33,817,510	$ 15,717,209	$ 8,520,232	$ 625,717	$ 4,067,976	$ 7,434,296	$ 37,231	$ 4,513,830	$ 119,494
16	Non-Reconcilable	302,382	99,367	40,476	3,245	4,888	50,228	193	45,036	620
17	Other Operation & Maintenance	47,028,789	16,048,054	6,351,999	1,089,547	618,197	6,826,367	58,126	6,751,813	370,836
18	Total Operation & Maintenance Expenses	81,148,681	31,864,630	14,912,707	1,718,510	4,691,062	14,310,890	95,551	11,310,680	490,950
19	Regulatory Debits and Credits	544,608	174,881	62,950	8,416	7,012	73,396	723	80,496	5,581
20	Depreciation & Amortization Expense	19,763,696	6,186,088	1,951,892	507,098	232,722	2,394,888	32,266	2,993,957	144,878
21	Decommissioning and Accretion Expense	23,522	7,710	3,122	214	378	3,878	13	3,505	52
22	Taxes Other Than Income Taxes	13,957,050	4,629,147	1,690,191	274,490	298,459	1,917,604	19,102	2,070,784	84,892
23	Current Income Taxes									
24	Federal	3,854,226	1,022,305	158,976	85,375	(76,822)	299,417	8,424	612,478	28,034
25	State	510,265	143,282	29,594	10,913	(4,639)	45,632	1,062	80,083	3,477
26	Total Current Income Taxes	4,364,491	1,165,587	188,570	96,289	(81,461)	345,049	9,487	692,561	31,511
27	Deferred Income Taxes									
28	Federal	1,233,475	558,343	307,895	18,418	133,454	277,509	876	164,044	6,158
29	State	208,629	79,904	36,232	3,855	12,640	36,050	247	29,743	1,163
30	Total Deferred Income Taxes	1,442,104	638,248	344,127	22,273	146,094	313,560	1,124	193,788	7,322
31	Amortization of Investment Tax Credits	(318,125)	(104,540)	(42,583)	(3,414)	(5,143)	(52,843)	(203)	(47,381)	(652)
32	Total Operating Expenses	$ 120,926,027	$ 44,561,750	$ 19,110,975	$ 2,623,876	$ 5,289,122	$ 19,306,422	$ 158,061	$ 17,298,391	$ 764,533
33										
34	Operating Income (Return)	$ 41,628,226	$ 11,189,862	$ 3,347,012	$ 737,264	$ 406,059	$ 4,123,220	$ 64,690	$ 6,599,169	$ (51,988)

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

SCHEDULEL P-1.4
PAGE 3 OF 4

Direct Testimony of
RJ Stanley for Vinton Steel
Exhibit RJS-1

EL PASO ELECTRIC COMPANY
2021 TEXAS RATE CASE FILING
SCHEDULE P-1.4: PROPOSED RATE SCHEDULES / EXISTING RATE CLASSES
SPONSOR: ADRIAN HERNANDEZ
PREPARER: ADRIAN HERNANDEZ
FOR THE TEST YEAR ENDED DECEMBER 31, 2020

USES CAPPED/FLOORED REVENUES FROM EXHIBIT MC-4

Line No.	(a) Description	(b) Rate 24 General Service	(c) Rate 25 Large Power	(d) Rate 26 Petroleum Refinery	(e) Rate 28 Area Lighting	(f) Rate 30 Electric Furnace	(g) Rate 31 Military Reservation	(h) Rate 34 Cotton Gin	(i) Rate 41 City and County	(j) WH Water Heating
35	Rate Base									
36	Plant in Service	740,731,569	230,315,390	69,931,330	16,672,182	8,459,050	86,769,056	1,277,118	112,847,872	4,948,590
37	Accum Depreciation & Amortization	(243,649,660)	(76,222,397)	(24,758,071)	(6,306,397)	(2,979,670)	(30,607,746)	(365,338)	(36,859,553)	(1,744,566)
38	Net Plant In Service	497,081,908	154,092,992	45,173,260	10,365,785	5,479,380	56,161,310	911,779	75,988,319	3,204,024
39										
40	Additions to Rate Base									
41	CWIP	-	-	-	-	-	-	-	-	-
42	Working Cash	(506,419)	(173,629)	(68,969)	(11,760)	(6,712)	(74,119)	(624)	(73,313)	(3,996)
43	Fuel Inventory	322,833	150,042	81,337	5,973	38,834	70,970	355	43,090	1,141
44	Nuclear Fuel	-	-	-	-	-	-	-	-	-
45	Materials & Supplies	10,022,798	3,146,830	938,894	269,233	109,329	1,133,846	20,032	1,524,442	67,700
46	Prepayments	2,817,864	901,711	317,320	46,488	36,300	376,633	3,805	419,514	24,098
47	Coal Reclamation Asset	-	-	-	-	-	-	-	-	-
48	Regulatory Assets	1,938,977	601,074	176,208	40,434	21,374	219,070	3,557	296,409	12,498
49	Accumulated Deferred Income Taxes	20,336,372	6,278,110	1,780,677	469,785	210,120	2,167,566	40,841	3,100,348	172,276
50	Tax Regulatory Assets	2,565,196	795,198	233,117	53,493	28,276	289,821	4,705	392,139	16,534
51	Miscellaneous Deferred Debits	814,908	267,790	109,080	8,745	13,174	135,363	521	121,371	1,670
52	Total Additions to Rate Base	38,312,530	11,967,126	3,567,665	882,391	450,695	4,319,149	73,192	5,824,001	291,921
53										
54	Deductions to Rate Base									
55	Customer Deposits	(129,241)	(6,098)	(2,341)	(13,681)	(1,126)	(2,044)	(43)	(15,153)	(131)
56	Regulatory Liabilities	-	-	-	-	-	-	-	-	-
57	Accumulated Deferred Income Taxes	(68,035,652)	(21,142,400)	(6,378,170)	(1,510,260)	(771,905)	(7,916,730)	(118,705)	(10,371,645)	(451,532)
58	Tax Regulatory Liabilities	(45,270,616)	(14,033,672)	(4,114,053)	(944,041)	(499,022)	(5,114,765)	(83,038)	(6,920,465)	(291,799)
59	Customer Advances - Construction	(4,840,840)	(1,313,846)	(89)	(297,642)	(25)	(117)	(23,591)	(780,474)	(79,989)
60	Total Deductions from Rate Base	(118,276,349)	(36,496,016)	(10,494,653)	(2,765,624)	(1,272,078)	(13,033,656)	(225,377)	(18,087,738)	(823,451)
61										
62	Total Rate Base	$ 417,118,090	$ 129,564,102	$ 38,246,272	$ 8,482,552	$ 4,657,997	$ 47,446,804	$ 759,594	$ 63,724,582	$ 2,672,494
63										
64	Rate of Return on Rate Base	9.980%	8.637%	8.751%	8.692%	8.717%	8.690%	8.516%	10.356%	-1.945%
65	Relative Rate of Return	1.250	1.082	1.096	1.088	1.092	1.088	1.067	1.297	(0.244)
66										
67	Total Revenue Requirement	$ 162,554,254	$ 55,751,612	$ 22,457,987	$ 3,361,140	$ 5,695,181	$ 23,429,642	$ 222,752	$ 23,897,560	$ 712,545
68	Less: Fuel & Other Sales For Resale Revenues	33,817,510	15,717,209	8,520,232	625,717	4,067,976	7,434,296	37,231	4,513,830	119,494
69	Less: Other Operating Revenues	5,296,351	1,626,997	587,933	32,436	72,452	738,975	3,254	750,793	47,592
70	Less: Base Rate Revenues at Present Rates	125,887,839	36,242,518	11,080,392	2,932,614	1,206,088	13,155,852	133,020	19,258,401	475,647
71	Equals:									
72	Non-Fuel Base Revenue Increase	$ (2,447,447)	$ 2,164,888	$ 2,269,429	$ (229,627)	$ 348,665	$ 2,100,519	$ 49,247	$ (625,464)	$ 69,812
73	Proposed Percent Increase	-1.944%	5.973%	20.481%	-7.830%	28.909%	15.966%	37.022%	-3.248%	14.677%

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

El Paso Electric Company
Loads & Resources 2021-2030 w/ 2021 Updated Load Forecast
Issued 7/2/2020

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
		170 Solar 100/50 Sol/Batt	Newman 6		48 Geo 100/100 Sol/Batt		130 Solar CT 100 CT 228			48 Geo
1.0 GENERATION RESOURCES[1]										
1.1 RIO GRANDE	271	271	227	227	227	227	227	227	227	227
1.2 NEWMAN	729	729	809	809	809	809	496	496	496	496
1.3 COPPER	63	63	63	63	63	63	63	63	63	63
1.4 MONTANA	352	352	352	352	352	352	352	352	352	352
1.5 PALO VERDE	622	622	622	622	622	622	622	622	622	622
1.6 RENEWABLES[2]	6	6	6	5	5	5	5	5	5	5
1.7 STORAGE	0	0	0	0	0	0	0	0	0	0
1.8 POSSIBLE EMERGING TECHNOLOGY EXPANSION[3]	0	0	0	0	40	40	40	40	40	40
1.9 INTERRUPTIBLE[4]	56	56	56	56	56	56	56	56	56	56
1.10 LINE LOSSES FROM OTHERS[5]	8	8	8	8	8	8	8	8	8	8
1.0 TOTAL GENERATION RESOURCES	**2107**	**2107**	**2143**	**2142**	**2182**	**2182**	**1869**	**1869**	**1869**	**1869**
2.0 RESOURCE PURCHASES										
2.1 RENEWABLE PURCHASE[6]	73	72	72	72	71	71	70	70	69	69
2.2 NEW RENEWABLE PURCHASE[7]	0	43	42	42	42	42	41	41	41	41
2.3 NEW RENEWABLE/ BATTERY PURCHASE[8]	0	75	75	75	75	75	74	74	74	74
2.4 NEW BATTERY PURCHASE[9]	0	0	0	0	0	0	0	0	0	0
2.5 MARKET RESOURCE PURCHASE[10]	195	100	95	125	0	20	15	45	100	100
2.0 TOTAL RESOURCE PURCHASES	**268**	**290**	**284**	**314**	**188**	**208**	**200**	**230**	**284**	**284**
3.0 FUTURE RESOURCES[11]										
3.1 RENEWABLE	0	0	0	0	48	48	81	81	81	129
3.2 RENEWABLE/STORAGE	0	0	0	0	100	100	100	100	100	100
3.3 GAS GENERATION	0	0	0	0	0	0	328	328	328	328
3.0 TOTAL RESOURCE PURCHASES	**0**	**0**	**0**	**0**	**148**	**148**	**509**	**509**	**509**	**557**
4.0 TOTAL NET RESOURCES (1.0 + 2.0 + 3.0)	**2375**	**2397**	**2427**	**2456**	**2518**	**2538**	**2578**	**2608**	**2662**	**2710**
5.0 SYSTEM DEMAND[12]										
5.1 NATIVE SYSTEM DEMAND[13]	**2138**	**2189**	**2227**	**2255**	**2296**	**2335**	**2379**	**2417**	**2471**	**2522**
5.2 DISTRIBUTED GENERATION	(9)	(19)	(22)	(22)	(22)	(22)	(22)	(22)	(22)	(22)
5.3 ENERGY EFFICIENCY	(8)	(15)	(23)	(31)	(38)	(46)	(54)	(62)	(69)	(77)
6.0 TOTAL SYSTEM DEMAND (5.1 - (5.2+5.3))	**2121**	**2155**	**2182**	**2202**	**2236**	**2267**	**2303**	**2334**	**2380**	**2423**
7.0 MARGIN OVER TOTAL DEMAND (4.0 - 6.0)	**254**	**242**	**245**	**254**	**282**	**271**	**275**	**274**	**282**	**287**
8.0 PLANNING RESERVE 15% OF TOTAL DEMAND	**318**	**323**	**327**	**330**	**335**	**340**	**345**	**350**	**357**	**364**
9.0 MARGIN OVER RESERVE (7.0 - 8.0)	**(64)**	**(81)**	**(82)**	**(76)**	**(53)**	**(70)**	**(71)**	**(76)**	**(75)**	**(77)**

1. Generation unit retirements are consistent with the 2018 IRP. Rio Grande 6 is classified as inactive reserve.
2. Existing EPE owned solar renewables at 70 percent contribution to peak.
3. Emerging technologies may include customer or other distributed resources as well as additional community solar.
4. Interruptible customer capacity shifted to the resource side of the L&R. Capacity MW contribution per 2020 Load Forecast.
5. Line losses from others shifted to resource side of the L&R and is the typical amount of repayment of transmission wheeling losses from transmission customers with in-kind energy during peak hours.
6. Existing renewable solar PPAs at 70 percent contribution to peak.
7. New renewable solar PPAs at 25 percent contribution to peak.
8. New solar and battery storage PPAs with solar at 25 percent contribution to peak.
9. 50 MW stand-alone battery was denied in NMPRC Case No. 19-00348-UT. The resource purchase on line 2.5 was adjusted to replace 50 MW capacity as required to meet the planning reserve margin.
10. Denotes market purchase either spot market or short-term purchased power. Amounts greater than 645 MW-PV output will need to come into EPE via exchange (Freeport), through the acquisition of additional transmission or on a non-firm path. Also, availability of such power is not guaranteed.
11. Future Resources from 2025 forward are to address both NM RPS and capacity needs. EPE will be initiating its 2021 IRP planning cycle which may result in changes to future planned resources.
12. System demand is based on the 2020 Long-Term Forecast dated April 1, 2021.
13. Native System Demand includes added load due to Electric Vehicles.

Planned Generation Additions
100 MW Solar (25 MW at Peak) in 2022
Solar/Batt Combo (100/50 MW) in 2022 (75 MW at Peak)
Newman 6 GT5 (228 MW) in 2023
70 MW Solar (18 MW at Peak) in 2022

Unit Retirements
Rio Grande 6 (45MW) (inactive reserve)
Rio Grande 7 (44MW) - December 2022
Newman 1 (74MW) - December 2022
Newman 2 (74MW) - December 2022
Newman 3 (93MW) - December 2026
Newman 4 CC (220MW) - December 2026
Copper (63MW) - December 2030
Rio Grande 8 (139MW) - December 2033

Company Owned Renewables
Line 1.6 consists of EPE Community Solar, Holloman Solar, EPCC, Stanton, Wrangler, Rio Grande & Newman Carports and Van Horn

Renewable Purchases
Line 2.1 includes SunEdison, NRG, Macho Springs, Juwi, and Hatch solar purchases (70% availability at Peak)

New Renewable Purchase
Line 2.2 includes system solar resource 100 MW Solar (25 at Peak) and NM RPS solar resource 70 MW in 2022 (18 MW at Peak)

Resource Purchase
This purchase is supported by firm transmission through (i) simultaneous buy/sell with
(i) Freeport McMoRan (formerly Phelps Dodge),
(ii) Four Corners-West Mesa transmission

Future Resources (subject to RFP results)
Line 3.0 includes
48 MW Geothermal NM RPS resource in 2025
100/100 MW Solar/Batt Combo NM RPS in 2025
130 MW Solar (33 MW at Peak) system resource in 2027
100 MW CT system resource in 2027
228 MW CT System Resource in 2027

SOAH DOCKET NO. 473-21-2606
PUC DOCKET NO. 52195

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

EL PASO ELECTRIC COMPANY'S RESPONSE TO
FREEPORT-MCMORAN, INC'S FIRST REQUEST FOR INFORMATION
QUESTION NOS. FMI 1-1 THROUGH FMI 1-25

FMI 1-7:

The following Interrogatories pertains to the Direct Testimony of David C. Hawkins.

Referring to Exhibit DCH-3, please explain why the interruptible load is treated as a capacity resource rather than a reduction in system demand.

RESPONSE:

The interruptible load is a dispatchable capacity resource in that EPE can call on it as needed and that is being relied on to serve peak load. As a result, it is included in the total resources to meet the peak load and planning reserve margin.

Preparer: Omar Gallegos — Title: Senior Director – Resource Planning Management

Sponsor: David C. Hawkins — Title: Vice President – Strategy and Sustainability

SOAH DOCKET NO. 473-21-2606
PUC DOCKET NO. 52195

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

EL PASO ELECTRIC COMPANY'S RESPONSE TO
VINTON STEEL, LLC'S FIRST REQUEST FOR INFORMATION
QUESTION NOS. VS 1-1 THROUGH VS 1-29

VS 1-14:

Please refer to the testimony of Manuel Carrasco, page 62, lines 6-11. EPE proposes to increase the demand charges in Rate 38 while lowering the energy charges. What is the average load factor of existing Rate 38 customers? Please explain whether Rate 38 customers with lower monthly load factors will experience a smaller rate increase as compared to the overall average increase to the interruptible class of customers?

RESPONSE:

Please refer to the table below, which is sorted by Average Load Factor.

Customer	Average Load Factor	Non-Firm Base Revenue Increase %
Account G	0.27	16.6%
Account D	0.45	8.6%
Account C	0.49	19.8%
Account E	0.62	7.5%
Account B	0.64	4.2%
Account I	0.70	2.8%
Account H	0.83	-5.2%
Account F	0.85	-7.2%
Account A	0.88	-9.6%

The proposed overall average non-firm base revenue increase is 7.8%. The percentage increase for each customer in the table above is a function of monthly load factors and the amount of interruptible load above the firm capacity the customer contracted for.

Preparer: Manuel Carrasco — Title: Manager – Rate Research

Sponsor: Manuel Carrasco — Title: Manager – Rate Research

SOAH DOCKET NO. 473-21-2606
PUC DOCKET NO. 52195

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

EL PASO ELECTRIC COMPANY'S RESPONSE TO
CITY OF EL PASO'S NINTH REQUEST FOR INFORMATION
QUESTION NOS. CEP 9-1 THROUGH CEP 9-43

CEP 9-38:

Has EPE imposed any interruptible penalties in years prior to 2020? If yes specify the amounts by year.

RESPONSE:

Yes.

Year	Schedule No. 38 Interruptible Penalties
2016	$224,188.91
2017	$236,450.24
2018	$217,484.08
2019	$0.00

Preparer: John Zacarias   Title: Supervisor – Billing

Sponsor: Manuel Carrasco   Title: Manager – Rate Research

SOAH DOCKET NO. 473-21-2606
PUC DOCKET NO. 52195

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

EL PASO ELECTRIC COMPANY'S RESPONSE TO
VINTON STEEL, LLC'S FIRST REQUEST FOR INFORMATION
QUESTION NOS. VS 1-1 THROUGH VS 1-29

VS 1-6:

Has EPE investigated the level of price elasticity related to the increase in prices of all electric rates, including the Noticed Interruptible Tariff? If so, please explain, in detail.

RESPONSE:

Yes. EPE's Load Research and Data Analytics Department produced a Price Elasticity Analysis in 2020 that focused on EPE's Residential, Small Commercial, and Large Commercial customer classes. The analysis employed a cointegrating equation with a distributed lag in order to obtain long-run and short-run price elasticities. The average price of electricity was used as the explanatory variable as real-time pricing mechanisms have not yet been implemented in the EPE service territory. EPE did not derive price elasticities specifically for interruptible customers.

Preparer: James Schichtl — Title: Vice President – Regulatory and Governmental Affairs

Sponsor: James Schichtl — Title: Vice President – Regulatory and Governmental Affairs