COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF:

THE ELECTRONIC APPLICATION OF	)	
EAST KENTUCKY POWER COOPERATIVE, INC.	)	
FOR A GENERAL ADJUSTMENT OF RATES,	)	Case No. 2021-00103
APPROVAL OF DEPRECIATION STUDY,	)	
AMORTIZATION OF CERTAIN REGULATORY	)	
ASSETS, AND OTHER RELIEF	)	

DIRECT TESTIMONY

AND EXHIBITS

OF

STEPHEN J. BARON

ON BEHALF OF

NUCOR STEEL GALLATIN

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

June 29, 2021

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TABLE OF CONTENTS

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DIRECT TESTIMONY OF STEPHEN J. BARON

I. QUALIFICATIONS AND SUMMARY

Q. Please state your name and business address.

A. My name is Stephen J. Baron. My business address is J. Kennedy and Associates, Inc. ("Kennedy and Associates"), 570 Colonial Park Drive, Suite 305, Roswell, Georgia 30075.

Q. What is your occupation and by who are you employed?

A. I am the President and a Principal of Kennedy and Associates, a firm of utility rate, planning, and economic consultants in Atlanta, Georgia.

Q. Please describe briefly the nature of the consulting services provided by Kennedy and Associates.

A. Kennedy and Associates provides consulting services in the electric and gas utility industries. Our clients include state agencies and industrial electricity consumers. The firm provides expertise in system planning, load forecasting, financial analysis, cost-of-service, and rate design. Current clients include the Georgia and Louisiana Public Service Commissions, and industrial consumer groups throughout the United States.

Q. Please state your educational background and experience.

A. I graduated from the University of Florida in l972 with a B.A. degree with high honors in Political Science and significant coursework in Mathematics and Computer Science. In 1974, I received a Master of Arts Degree in Economics, also from the University of Florida.

I have more than forty years of experience in the electric utility industry in the areas of cost and rate analysis, forecasting, planning, and economic analysis.

I have presented testimony as an expert witness in Arizona, Arkansas, City of New Orleans, Colorado, Connecticut, District of Columbia, Florida, Georgia, Indiana, Kentucky, Louisiana, Maine, Michigan, Minnesota, Maryland, Missouri, Montana, New Jersey, New Mexico, New York, North Carolina, Ohio, Pennsylvania, South Carolina, South Dakota, Texas, Utah, Virginia, West Virginia, Wisconsin, Wyoming, the Federal Energy Regulatory Commission and in United States Bankruptcy Court.

A complete copy of my resume and my testimony appearances is contained in Baron Exhibit__(SJB-1).

Q. On whose behalf are you testifying in this proceeding?

A. I am testifying on behalf of Nucor Steel Gallatin ("Nucor Gallatin").

Q. Have you previously testified in East Kentucky Power Cooperative, Inc. ("EKPC") rate proceedings before the Kentucky Public Service Commission?

A. Yes. I testified in two prior cases in 2009 and 2010 (Case Numbers 2008-00409 and 2010-00167).

Q. What is the purpose of your testimony?

A. I present testimony in response to EKPC witness Richard Macke on class cost of service issues and the allocation of the overall revenue increase to rate classes. In addition, I address the Company's proposed 10-minute notice interruptible rates for Nucor Gallatin.

With regard to class cost of service issues, I discuss EKPC's proposal to use an Average and Excess Demand ("AED") production cost allocation methodology. While I do not object to the use of an AED methodology, I have identified three significant errors in EKPC witness Macke's cost study that must be corrected, beyond the correction to Nucor's NCP demand that EKPC has already made in response to Nucor discovery in this case. In addition, I will discuss a significant deficiency with the EKPC AED cost study due to its failure to reasonably reflect cost responsibility for fuel and purchased power energy expenses. Though the cost of service study removes fuel and purchased energy expenses and revenues from the study, the EKPC analysis fails to properly measure differences between on and off-peak energy costs incurred to serve each rate class, compared to the base fuel charge and FAC that is charged to customers for these costs. I will present a number of analyses that correct the Mr. Macke's errors and demonstrate that his class cost of service study, even after making the NCP demand correction, fails to correctly and accurately measure the cost of service for each EKPC rate class. I will present a corrected class cost of service study and recommend an alternative set of rate class increases.

With regard to EKPC's proposed interruptible credits for its Contract class customer, Nucor Gallatin, I recommend an increase. EKPC is not proposing to change the current interruptible credits for either the 10-minute notice and 90-minute notice interruptible service. These credits were first established over 10 years ago in EKPC's 2010 rate case (Case No. 2010-00167). I will discuss concerns with the reasonableness of the current 10-minute notice interruptible credit, in light of the Commission's recent determination in the Kentucky Power Company Net Metering

Case (20-00174) in which the Commission determined that the appropriate measure of avoided capacity cost is the PJM Net Cone value (Net Cost of New Entry).

Q. Would you please summarize your testimony?

A. Yes. I recommend and conclude the following:

- **Mr. Macke's cost of service study erroneously used 15-minute billing demands to develop Nucor's AED factor and Nucor's 12 CP demands. Mr. Macke also erroneously used 15-minute demands to develop the 12 CP allocation factors for other rate classes. These factors are used to allocate production demand and transmission costs. EKPC has acknowledged its error in the determination of NCP billing demand for the Contract class serving Nucor and presented a corrected version in response to discovery. However, EKPC should also have used hourly demands to calculate the 12 CP demand allocator (rather than 15-minute demands). For Nucor, Mr. Macke used billing demands that are not even tied to the coincident peak hour. Hourly demands are the basis for generation and transmission planning and thus the appropriate metric to measure cost responsibility. This is a standard practice in every cost of service study I have ever seen presented in Kentucky, or anywhere else.**

- **Mr. Macke's AED class cost of service study also incorrectly applied the AED methodology to allocate production related fixed costs. Specifically, EKPC separated its production demand costs into demand related and energy related components, correctly following the AED methodology, by applying the system load factor and (1 minus the system load factor) weights to the total production capacity costs. Mr. Macke then, erroneously, allocated the demand component using the entire AED allocator (weighted average demand and excess demand), rather than just excess demand. The result of this error was to double count the average demand (energy) component of the AED factor. My correction is consistent with the NARUC cost allocation manual and the AED cost study recently presented to the Commission by Big Rivers Electric witness John Wolfram.**

- **Mr. Macke's cost of service study failed to annualize a significant (15.2 MW) increase in the MW demand of Contract class customer Nucor**

Gallatin as a result of the addition of a galvanizing line in late 2019. This caused a significant increase in Nucor Gallatin's load, for cost allocation purposes, but did not annualize Nucor Gallatin's revenues to reflect this known and measurable increase in load. As a result, the reported cost of service results are not an accurate measure of the cost to serve the Contract class. To correct this significant mismatch, the galvanizing line load and revenues in 2019 should be removed from the class cost of service study. This adjustment provides a more reasonable measurement of the relationship between Nucor's test year cost of service and the rates paid by Nucor.

- **These three errors must be corrected to produce a reasonable and accurate measure of cost responsibility. I present a corrected version of the cost of service study that fixes these three errors.**

- **Mr. Macke's cost of service study also failed to reflect the cost imbalance among rate classes associated with fuel/purchased power costs and fuel/purchased power revenues. Specifically, his removal of fuel and purchased power costs and revenues from the cost of service study ignores differences in rate class fuel and purchased energy costs resulting from different on-peak and off-peak usage patterns. This problem should be corrected using the methodology that I discuss in this testimony.**

- **EKPC's proposed revenue increases to each rate class are not reasonable and should be rejected because they are based on a flawed class cost of service study. The Commission should adopt a revenue distribution that reflects the results of a corrected class cost of service study and recognizes the economic development impact of electric rates to energy intensive industrial customers. I recommend that: 1) Rate B, Rate C and Rate TGP receive no rate increase; 2) the Contract Class (Nucor) receive no more than a cost-of service based rate increase; and 3) Rate E, Rate G and the Steam Class receive a uniform percentage increase.**

- **EKPC's proposed 10-minute interruptible credit should be increased to reflect avoided capacity cost based on the PJM Net CONE rate, consistent with the Commission's recent decision in the Kentucky Power Company Net Metering case (2020-000174).**

II. CLASS COST OF SERVICE

Q. Please briefly describe Nucor.

A. Nucor operates an electric arc steelmaking facility in Northern Kentucky along the Ohio River. The original plant went commercial in the mid-1990s. Nucor purchased Gallatin Steel in 2014. At a cost of approximately $200 million, Nucor added a galvanizing line which went commercial at the end of 2019 (the end of the test year in this case). The plant is currently in a $650 million expansion that will basically double its steelmaking capacity. Once the expansion is complete at the end of 2021 it will be one of the largest electric consumers in the country, with a load of approximately 400 MW and an energy usage that will equal approximately 166,000 residential households.

Q. Have you reviewed Mr. Macke's proposed class cost of service study filed in this case?

A. Yes. Mr. Macke is proposing to utilize an Average and Excess Demand ("AED") methodology to allocate production demand costs in its class cost of service study in this case. The AED methodology is a traditional cost of service methodology recognized in the NARUC Electric Utility Cost Allocation Manual (NARUC Manual). It is used by a number of electric utilities and has been accepted by numerous regulatory commissions (see EKPC response to Staff's Second Request for Information, Request 22). EKPC used the A&E cost of service methodology in two prior cases (Case Nos. 94-336 and 2006-00472).

Q. Have you supported the use of an AED class cost of service study in prior cases in which you have participated?

A. Yes. I have testified in Dominion Energy Virginia, Public Service Company of Colorado and Southwestern Public Service Company cases in which these Companies utilized AED cost of service studies.[1] In each of these cases, I have supported the AED methodology as a reasonable basis to measure rate class cost responsibility. Of course, the AED methodology needs to be applied correctly in order to rely on the cost of service results.

Q. Would you summarize the 3 errors that you have found in your review of Mr. Macke's class cost of service study?

A. The first error concerns his use of 15-minute demands to calculate the 12 coincident peak allocation factors used to assign transmission costs to rate classes, except for Nucor. For Nucor, its 12 CP demands were determined by Mr. Macke using Nucor's billing demands that are based on maximum 15-minute on-peak demands, not coincident demands. The 12 CP allocation factors should be based on hourly demands, not 15-minute demands, and not billing demands, consistent with cost allocation studies performed in Kentucky and throughout the country. Mr. Macke

[1] Both Public Service Company of Colorado and Southwestern Public Service Company (New Mexico) use a variant of the AED method called the AED 4 CP methodology. Dominion Energy Virginia uses a traditional NCP based AED method, as described in the NARUC Electric Utility Cost Allocation Manual.

also erroneously used 15-minute billing demands to calculate the NCP demand for Nucor, while using hourly NCP demands for other rate classes. EKPC has acknowledged this error in its response to Nucor 1-6 and presented a corrected cost of service study in its response to Nucor 2-10. However, Mr. Macke did not revise his cost of service study to reflect a correct calculation of the 12 CP allocation factors using hourly CP demands for all rate classes.

The second significant error in the Mr. Macke's cost of service study involves the application of the Average and Excess Demand allocation factor to assign fixed production costs to rate classes. As I will explain, he double counted the average demand (energy) component of the AED factor in his cost study.

The third error in his cost of service study is due to a failure to properly reflect a matching of load and revenues associated with Nucor's new Galvanizing Line that became operational in late 2019. As a result, Nucor's NCP demand, which occurred on December 30, 2019, reflects almost the full level of the Galvanizing Line. NCP demand is a key component in the development of the excess demand component of the AED factor used to allocate fixed production costs to rate classes. For Nucor, this resulted in the excess demand portion of fixed production costs being assigned to it as though the Galvanizing Line were fully operational for the test year, without recognizing a full year level of revenues produced by the Galvanizing Line. This mismatch created a significant revenue deficiency for Nucor in the cost of service study.

Q. Is there an additional problem with Mr. Macke's cost of service study?

A. Yes. The study failed to properly reflect the difference between the responsibility of each EKPC rate class for fuel and purchased energy costs due to different on-peak and off-peak usage patterns and the revenue paid by each rate class for these costs.

A. The First Cost of Service Error

Q. Would you discuss the first error that you discovered in your review of the cost of service study?

A. Yes. This error occurred because the cost of service study used a combination of 15-minute CP demands for all rate classes other than Nucor. For Nucor, the cost study used 15-minute billing demands to determine the 12 CP demands used to allocate transmission costs.

Based on its Agreement for Electric Service, Nucor's billing demands are based on the greater of the maximum monthly 15-minute demand during the on-peak period or 83.33% of the maximum demand during the off-peak period. This means that EKPC erroneously calculated its 12 CP allocation factors using monthly 15-minute CP demands for Rates B, C, E and G, and used 15-minute maximum on peak demands (or 83.33% of its 15-minute off-peak demand) for Nucor's load. The Nucor billing demands are not necessarily coincident with the hour of the monthly EKPC system peak, but rather are based on the maximum on-peak demands. EKPC characterized its allocation factor as a traditional 12 CP allocation methodology. But EKPC's 12 CP allocation factors are not 12 CP demands and therefore assign transmission costs to rate classes erroneously and inaccurately.

Moreover, all of these demands are all based on 15-minute demands, not hourly demands that are the basis for system planning, load forecasting and the need for capacity and PJM planning and cost allocation to determine EKPC's costs for transmission – all of the factors that comprise cost causation.

Q. Did EKPC correct its cost of service study to use hourly demands to calculate the AED NCP demand for Nucor?

A. Yes. In his originally filed cost study, Mr. Macke used 15-minute billing demands to measure the NCP demand for the Contract class (Nucor Gallatin), though he used hourly demands to calculate the NCP demand for the other rate classes. In his original cost study, the maximum NCP demand used to determine Nucor Gallatin's AED allocation factor, based on Nucor's 15-minute billing demand, is shown to be 175 MW. However, the actual hourly maximum demand for Nucor Gallatin during

2019 is only 164 MW. EKPC, in response to Nucor 2-6 admits this error.[2] In response to Nucor 2-10, EKPC provided a corrected version of its cost of service study. Baron Exhibit__(SJB-3) presents a summary schedule from the EKPC study that uses the correct NCP demand for Nucor and Rate C.

Q. Did Mr. Macke make a similar correction to replace the 15-minute demands with hourly demand to calculate the 12 CP demand factors used for transmission cost allocation?

A. No.

Q. Should the 12 CP MW demands used to allocate transmission costs to rate classes be based on hourly rate class CP demands, rather than 15-minute demands?

A. Yes. Consistent with the calculation of NCP MW demands used in EKPC's AED methodology, the 12 CP demands should also be based on the hourly loads for each rate class, coincident with the system peak. There is no basis to use 15-minute demands for this important allocation. EKPC is a member of PJM, which bases its cost allocation on hourly loads, not 15-minute demands. EKPC's PJM OATT assigns transmission costs on the basis of hourly load. Baron Exhibit__(SJB-4) contains an excerpt from EKPC's Open Access Transmission Tariff ("OATT"). As

[2] Baron Exhibit__(SJB-2) contains a copy of EKPC's response to Nucor 2-6.

can be seen on page 2 of 2 of this exhibit, the determination of Network Load that is used to determine cost responsibility for EKPC's fixed transmission costs, is measured on an hourly basis, not on a 15-minute basis.

Q. Based on your 40 plus years of experience developing and evaluating electric utility class cost of service studies, have you ever seen a class cost of service study that calculates demand allocation factors using rate class 15-minute demands or billing demands, rather than hourly kW demands?

A. No. I have been in more than 121 cases involving class cost of service analysis across the United States, including 17 Kentucky Power Company, Louisville Gas and Electric, Kentucky Utilities and Big Rivers cases during my career and I have never seen a cost of service study that used billing demands or 15-minute CP demands to allocate production or transmission. The NARUC Manual never refers to the use of billing demands to develop allocation factors. EKPC acknowledges that the AED allocation factors in its cost study should be based on hourly NCP demand, not billing demand, but did not also correct its study to use hourly demands to develop the 12 CP allocation factors that are used in to allocate transmission costs to rate classes. As I discussed, this error is particularly problematic because Mr. Macke combined 15-minute CP demands for Rates B, C, E and G with 15-minute maximum on-peak (or 83.33% of the 15-minute off-peak demand) for Nucor.

Q. Have you corrected the class cost of service study to incorporate hourly demands?

A. Yes. Baron Exhibit__(SJB-5) presents a summary of this study, which begins with EKPC's corrected cost study provided in response to Nucor 2-10 and then corrects it further to reflect consistent hourly 12 CP demands for each rate class. These hourly 12 CP demands were provided by EKPC in response to Nucor 2-7.

B. The Second Cost of Service Error

Q. Before discussing the second error that you have identified with Mr. Macke's AED cost study, would you provide an overview of how the AED factors are correctly calculated and used to allocate costs in an AED class cost of service study?

A. Yes. To do this, I am going to rely on the NARUC Manual discussion of the AED methodology. There are generally two different approaches that can be used to allocate production demand costs in an AED cost study – both approaches produce the same result and the difference in the two approaches is essentially a presentation issue. The NARUC Manual presents hypothetical illustrations using both approaches to apply the AED methodology. Baron Exhibit__(SJB-6) contains an excerpt from the NARUC Manual describing the AED methodology. The two alternative calculations of the AED allocator are shown in Tables 4-10A and 4-10C in the NARUC Manual.

In Tables 1 and 2 below, I have created an excel version of each of these NARUC Manual illustrations with some additional columns of calculations to fill in more detail than shown in the NARUC Manual. Both illustrations use the same rate class load data and system cost data, and produce the same results as shown in the NARUC Manual tables.[3]

[I] It should be noted that the illustration in the NARUC Manual allocates a single production revenue requirement amount ($1,060,476,000), while in an actual AED cost study, such as the EKPC study, each production related plant and expense account is separately allocated (excluding fuel expense, purchased energy expense and other energy classified costs such as plant maintenance). However, this difference does not affect the cost allocation itself.

Table 1
NARUC Electric Utility Manual - Table 4-10A

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
	NCP MW	Average Demand	Average Demand Allocation %	Load Factor Wtd. Average Demand [3 X LF]	Excess Demand [5 = 1 -2]	Excess Demand Allocation %	(1 - minus Load Factor) Wtd. Excess Demand [6 X (1 - LF)]	AED Allocation % [4 + 7]	Production Revenue Requirement
DOM	5357	2440	30.96%	17.95%	2917	44.05%	18.51%	36.46%	386,682,685
LSMP	5062	2669	33.87%	19.64%	2393	36.14%	15.18%	34.82%	369,289,317
LP	3385	2459	31.21%	18.09%	926	13.98%	5.88%	23.97%	254,184,071
AG&P	572	254	3.22%	1.87%	318	4.80%	2.02%	3.89%	41,218,363
SL	126	58	0.74%	0.43%	68	1.03%	0.43%	0.86%	9,101,564
TOTAL	14502	7880	100.00%	57.98%	6622	100.00%	42.02%	100.00%	1,060,476,000
System Load Factor:		57.98%							
(1 - minus Load Factor)		42.02%							
Production Revenue Req.		1,060,476,000							

The first approach to calculate the AED allocator is shown in Table 1 and corresponds to NARUC Manual Table 4-10A. The calculation approach produces a single AED allocation factor that is applied to each production related cost (other than fuel, purchased energy and certain expenses such as steam plant maintenance costs that are classified as energy related and are not allocated using the AED factors). Columns (1) and (2) of the illustration contain the NCP demand kW and average demand kW for each rate class. Column (3) calculates the percentage share of average demand for each rate class. Following the AED methodology, as discussed in the NARUC Manual, column (4) shows the average demand percentage factors from column (3) weighted by the hypothetical system load factor of 57.98%. Column (5) calculates the "excess demand" by subtracting the average demand from column (2) from the NCP demand in column (1). These excess demands are then converted to percentage factors in column (6) and then weighted by 42.02% (1 – minus the system load of 57.98%) in column (7). Finally, the two sets of weighted factors in columns (4) and (7) are added together to produce a single AED allocation factor for each class. These final AED factors are shown in column (8). Allocated production revenue requirements based on the AED factors in column (8) are shown in column (9).

Q. Has the NARUC Manual Table 4-10A AED methodology been used in prior cost of service studies presented to the Kentucky Commission?

A. Yes. In Big Rivers Electric Corporation's ("Big Rivers") Case No. 2021-00061, Big Rivers witness John Wolfram presented an Average and Excess Demand cost of service study using the NARUC Manual approach that I just described. Mr. Wolfram correctly calculated a load factor weighted "average demand" and "excess demand" AED allocation factor. Unlike Mr. Macke's study, Mr. Wolfram correctly applied his AED factor to the total production related plant, accumulated depreciation and production expense balances. Mr. Wolfram's AED calculations were presented in his Exhibits Wolfram 4, pages 1 to 8 and Wolfram 6, page 1 of 3.

Q. Would you explain the second approach that can be used to calculate the AED allocation?

A. This approach, which is illustrated in NARUC Manual Table 4-10C and reproduced with additional detail in Table 2 below, first multiplies the cost at issue by the annual system peak load factor.[4]

Table 2
NARUC Electric Utility Manual Table 4-10C

	(1) NCP MW	(2) Average Demand	(3) Average Demand Allocation %	(4) Energy Component of Production Revenue Requirement [3 X Energy RR]	(5) Excess Demand [5 = 1 -2]	(6) Excess Demand Allocation %	(7) Demand Component of Production Revenue Requirement [6 X Demand RR]	(8) AED Allocated Production Revenue Requirement [4 + 7]
DOM	5357	2440	30.96%	190,387,863	2917	44.05%	196,294,822	386,682,685
LSMP	5062	2669	33.87%	208,256,232	2393	36.14%	161,033,085	369,289,317
LP	3385	2459	31.21%	191,870,391	926	13.98%	62,313,680	254,184,071
AG&P	572	254	3.22%	19,819,064	318	4.80%	21,399,298	41,218,363
SL	126	58	0.74%	4,525,613	68	1.03%	4,575,951	9,101,564
TOTAL	14502	7880	100.00%	614,859,163	6622	100.00%	445,616,837	1,060,476,000

Production Revenue Req.	1,060,476,000	
System Load Factor:	57.98%	
Energy Component of Prod Rev Req		614,859,163
(1 - minus Load Factor)	42.02%	
Demand Component of Prod Rev Req		445,616,837

The system load factor in this example is 57.98%. The costs allocated on rate class average demand are 57.98% of the total production revenue requirement of

[4] As I indicated, in the NARUC Manual illustration, total production demand revenue requirements are allocated, rather than individual plant and expense components.

$1,060,476,000, or $614,159,163. This is shown in column (4) and is referred to as the energy component of production revenue requirements.

The demand component of production revenue requirements is calculated by multiplying the total ($1,060,476,000) by 42.02% (1 minus the system load factor). This cost is allocated to rate classes based on each class's "excess demand." This is shown in column (7). The sum of these two components, shown in column (8), is the allocated cost for the class.

Q. How did Mr. Macke perform the AED calculation?

A. He erroneously combined both of the methods that I just described. His error results in an AED allocation that double counts the average demand (energy) component. Table 3 illustrates Mr. Macke's methodology using the same hypothetical data used in the NARUC Manual.

Table 3
Illustration of EKPC AED Error

	(1) NCP MW	(2) Average Demand	(3) Average Demand Allocation %	(4) Energy Component of Production Revenue Requirement [3 X Energy RR]	(5) Full Weighted AED Factor from Col (8) Table 4-10A	(6) Demand Component of Production Revenue Requirement [5 X Demand RR]	(7) AED Allocated Production Revenue Requirement [4 + 6]
DOM	5357	2440	30.96%	190,387,863	36.46%	162,485,823	352,873,685
LSMP	5062	2669	33.87%	208,256,232	34.82%	155,177,050	363,433,282
LP	3385	2459	31.21%	191,870,391	23.97%	106,809,303	298,679,694
AG&P	572	254	3.22%	19,819,064	3.89%	17,320,143	37,139,208
SL	126	58	0.74%	4,525,613	0.86%	3,824,518	8,350,132
TOTAL	14502	7880	100.00%	614,859,163	100.00%	445,616,837	1,060,476,000

Production Revenue Req.	1,060,476,000	
System Load Factor:	57.98%	
Energy Component of Prod Rev Req		614,859,163
(1 - minus Load Factor)	42.02%	
Demand Component of Prod Rev Req		445,616,837

First, Mr. Macke correctly calculates the energy component of production costs following the method shown in NARUC Manual Table 4-10A. I illustrated these calculations in columns (1) through (4) of Table 3. Note that these columns are identical to the first four columns of my Table 2.

As I will demonstrate subsequently, in his actual cost study he has allocated the production energy component on the basis of average demand (which was appropriate and consistent with the NARUC Manual), but then erroneously allocates the production demand component of cost using the entire weighted AED allocation factor, rather than the excess demand allocator. This error is shown in columns (5) and (6) of Table 3 using the hypothetical data from the NARUC Manual. Column (5) contains the full AED allocation factor, not the correct "excess demand" allocation factor. This allocator is used by Mr. Macke to allocate the excess portion of the production revenue requirement, which is $445,616,837 in the illustration. As can be seen in column (7) of Table 3, the final share of production revenue requirements for each rate class are different than the results using the correct methods shown in Tables 4-10A and 4-10C from the NARUC Manual.

Q. Would you now demonstrate that the EKPC study used this erroneous AED allocation that you have just illustrated?

A. Mr. Macke's cost of service study first classified each of the production plant, accumulated depreciation and depreciation expense items to energy by multiplying them by the EKPC system load factor. Production expenses are separately classified as either capacity or energy related and not classified on the basis of system load factor. For example, Maintenance of Boiler Plant expense (Account 512) is a direct assignment to production energy. Production energy costs, both those classified on the basis of system load factor and direct assignments such as Account 512) were then allocated to rate class using kWh energy, which was correct. Baron Exhibit__(SJB-7) is an excerpt from Mr. Macke's Exhibit RJM-2, page 1 of 17, Schedule A, page 1 of 3. It shows the classification of steam production plant in service (Accounts 310-316) into "Production Capacity" and

"Production Energy" components using the EKPC system load factor of 44.8%, after removing amounts directly assigned to "Steam Direct." A similar calculation was performed for all plant and expense items comprising the overall production energy revenue requirement.

Mr. Macke computed a total production capacity revenue requirement of $172,575,237. This production capacity revenue requirement consists of plant related costs that were developed by applying the "1 minus system load factor" value (55.2%) to production plant and related items, plus the directly assigned production capacity costs of $98.6 million. However, Mr. Macke then allocated the total production capacity revenue requirement by the total AED factor. As I explained above, the total AED factor already reflects a load factor weighing of average demand and excess demand. Since the production capacity revenue requirement already reflects this load factor weighting for the cost of production plant and related items of $74 million (total amount of $172.5 million less the directly assigned amount of $98.6 million), there is a double counting in the EKPC calculation. These costs should have been allocated to rate classes using the "excess demand factor" as I illustrated in my Table 2, based on the NARUC Manual. Mr. Macke erroneously allocated all of the $172.5 million in production capacity costs using the weighted AED factor. This can be seen in Mr. Macke's Exhibit RJM-2, page 17 of 17, Schedule G, page 1 of 1 at line 8. For example, the allocated Rate E share of the production capacity revenue requirement of $146,619,986 is 83.1141% of the total production capacity revenue requirement of $172,575,237. The 83.1141% value is the AED factor for Rate E, as shown on Exhibit RJM-2, page 16 of 17, Schedule F, page 1 of 1 at line 39.

Q. Have you corrected the EKPC cost of service study to fix this error?

A. Yes. My corrected study uses the AED approach presented in Table 4-10A of the NARUC Manual. This is the same approach used by Mr. Wolfram to develop his AED cost of service study in the Big River's case that I discussed earlier. My correction classifies 100% of the production plant, related accumulated depreciation and depreciation expense as capacity and then applies the load factor weighted AED factor to this amount, as was done by Mr. Wolfram and as presented in the NARUC Manual.

Baron Exhibit__(SJB-8) presents my corrected study. To show the impact of this AED error by itself, Exhibit SJB-8 only corrects the EKPC corrected cost study provided in response to Nucor 2-10 for the AED error – it does not correct the other errors that I have identified with Mr. Macke's study. As such, this cost study does not include my previous correction that uses hourly demands instead of 15-minute CP and Nucor billing demands for the 12 CP factor. As can be seen in Exhibit SJB-8, the increases shown on line 30 of the corrected cost of service study are quite different from EKPC's corrected study provide in response to Nucor 2-10 that I presented in Exhibit SJB-3.[5] In particular, the revenue deficiency is lower for the Contract class when the AED calculation is performed correctly.

C. The Third Cost of Service Error

Q. Will you discuss the third error that you identified with EKPC's class cost of service study related to a failure to annualize the effects of Nucor Gallatin's new galvanizing line that became operational at the end of 2019?

A. Yes. During the 2019 test year, Nucor Gallatin added a new galvanizing line to its operation. As explained in EKPC's response to AG-Nucor 1-17, the new galvanizing line became operational in late 2019. This new load is separately metered. In December 2019, the new galvanizing line was close to its full load of approximately 15.7 MW.

Q. Did the 15.7 MW galvanizing line impact the calculation of the AED allocator for Nucor Gallatin?

A. Yes. The AED allocation factor is comprised of an average demand component and an excess demand component. The excess demand is based on the difference

[5] This is the cost of service study provided by EKPC in response to Nucor 2-10 that correctly uses hourly NCP demand for Nucor.

between the rate class maximum NCP demand and the class's average demand. In the EKPC cost of service study, the maximum Nucor Gallatin NCP demand occurred in December 2019, due to the increased galvanizing load.

Q. Was it wrong for EKPC to use the December 2019 Nucor Gallatin load to establish the Contract class maximum NCP demand?

A. No. However, because this load did not occur until late in the year, Nucor Gallatin's revenues for 2019 did not reflect an accurate measure of the amount that Nucor would be paying for capacity and energy consistent with the new galvanizing line operation. This created a significant mismatch between the costs allocated to serve Nucor Gallatin, which were based on its maximum NCP demand in December 2019 and the revenues reported for Nucor Gallatin in 2019, based on only a partial year of operation of the galvanizing line, that are used in the class cost of service study. This contributed significantly to the revenue deficiency for Nucor Gallatin that is shown in the cost of service study. In summary, the cost study indicates that the Nucor Gallatin demand and energy rates are too low, given the cost to service its load. However, a part of this revenue deficiency is occurring because EKPC did not normalize the Nucor Gallatin galvanizing line load and revenues for the test year.

Q. How are such material mismatches typically treated in ratemaking?

A. There should be an annualization adjustment to align the costs assigned to Nucor Gallatin and the revenues attributable to this customer. However, because of the complexities in performing an accurate normalizing adjustment, the most appropriate way to deal with this mismatch issue is to remove the galvanizing line load, energy and revenues from the class cost of service study. The remaining Nucor load and revenues will then be matched and the resulting cost of service results will reflect a reasonable measure of how Nucor Gallatin's rates compare to cost of service.

Q. Have you developed an adjustment to fix this mismatch by removing the partial year galvanizing line load, energy and revenues from EKPC's cost study?

A. Yes. Based on the responses to Nucor's supplemental data requests (2-3, 2-4, and 2-5), I was able to remove the galvanizing line revenues, energy, NCP excess demand and 12 CP demand each month in 2019 from the Contract class. Baron Exhibit__(SJB-9) presents a summary of the corrected cost study. As in my prior corrections, this analysis is based on EKPC's corrected cost study provided in response to Nucor 2-10 and only reflects the impact of the removal of the galvanizing line demand, energy and revenues from the cost study. It does not reflect the other corrections that I previously discussed.

D. Impact of all 3 Cost of Service Study Corrections

Q. Have you prepared a class cost of service study that corrects all 3 of the errors that you have discussed (12 CP hourly loads, AED allocation factor application, Nucor galvanizing line mismatch)?

A. Yes. Baron Exhibit__(SJB-10) presents a summary of this cost study that corrects these errors. Table 4 provides a summary showing the impacts of each of the corrections and a final cost study that includes all of the corrections. Also shown, for comparison, are the results of Mr. Macke's originally filed cost study and EKPC's corrected cost study provided in response to Nucor 2-10.

These three corrections reduce the Contract rate class revenue deficiency from $5,828,074 (24.6%) in EKPC's originally filed study to $1,610,037 (6.9%) in the corrected study. Based on a corrected class cost of service study, the Contract class should receive a significantly below average increase in this case (6.9% vs. the average increase of 11.6%). It is also important to recognize that these increases are directly from the class cost of service model, before EKPC's adjustment to reduce the overall revenue increase from $48.98 million to $42.99 million, and before any additional revenue requirement reductions ordered by the Commission.

Table 4
Summary of Cost of Service Study Corrections

	Combined Impact of the Correction of All 3 Errors*		Standalone Impacts of Correction									
			Remove Nucor Galvanizing Line (SJB-9)		AED Correction (SJB-8)		1 Hr 12CP Correction (SJB-5)		EKPC Corrected (1Hr NCP) Response to Nucor 2-10 (SJB-3)		EKPC as Filed	
	Required Increase	% Incr	Required Increase	% Incr	Required Increase	% Incr	Required Increase	% Incr	Required Increase	% Incr	Required Increase	% Incr
Rate B	10,432	0.0%	2,069,778	7.6%	(76,408)	-0.3%	2,090,064	7.7%	2,032,216	7.5%	2,014,236	7.4%
Rate C	(461,684)	-5.8%	48,725	0.6%	(455,463)	-5.7%	20,356	0.3%	36,837	0.5%	975,886	12.3%
Rate E	46,665,137	13.6%	40,317,637	11.8%	44,326,584	12.9%	40,511,173	11.8%	39,299,131	11.5%	38,006,884	11.1%
Rate G	910,629	8.4%	1,866,944	17.2%	862,443	8.0%	1,888,653	17.4%	1,851,694	17.1%	1,845,844	17.0%
Contract	1,610,037	6.9%	4,431,467	19.1%	3,806,778	16.1%	3,953,687	16.7%	5,244,054	22.1%	5,828,074	24.6%
Steam	304,231	6.7%	304,231	6.7%	309,227	6.8%	309,227	6.8%	309,227	6.8%	313,013	6.9%
Rate TGP	-	0.0%	-	0.0%	-	0.0%	-	0.0%	-	0.0%	-	0.0%
Total	49,038,782	11.6%	49,038,782	11.6%	48,773,161	11.6%	48,773,161	11.6%	48,773,161	11.6%	48,983,937	

* These cost of service results reflect the correction of all 3 errors and includes the interactions among the corrections.

E. Adjustment to Reflect Energy Cost vs. Energy Revenue Disparity

Q. Are there any additional changes that should be made to EKPC's class cost of service study in order to more accurately measure the cost responsibility for each rate class?

A. Yes. EKPC removed fuel and purchased power expenses and the offsetting base fuel revenues and FAC revenues from the class cost of service study. The intent of these adjustments was to develop a cost study that only reflects the base rate revenue requirements at issue in this case.

Q. Is EKPC's approach to remove base fuel and FAC revenues and corresponding expenses reasonable?

A. In theory, removing these fuel revenue and expense items is reasonable, since this proceeding only focuses on costs that are recovered in base rates. However, EKPC's adjustments assume that the fuel and purchased energy costs are equal for each rate class on a $/MWh basis. While all of EKPC's rates (B, C, E, G, Contract) are charged the same amount for fuel and purchased energy cost in base rates (currently $0.02624/kWh), and pay the same FAC, the actual fuel and purchased energy cost to service each rate class is different, reflecting differences in each class's mix of on and off-peak kWh. In particular, because the Contract class (Nucor Gallatin) has a higher than average load factor, it has a proportionately greater share of its total usage during off-peak hours when the cost of fuel and purchased energy is lower. While the fuel and purchased energy costs incurred by EKPC to serve higher load factor rate classes (like the Contract class) are lower, the fuel and purchased energy revenues paid by these high load factor class do not reflect this cost difference. Stated differently, with respect to fuel and purchased power costs, it is more expensive to serve a class that predominately uses on-peak energy. This difference (energy costs vs. energy revenues) creates a subsidy that is paid by higher load factor rate classes to lower load factor classes that is not recognized in the EKPC cost of service study.[6]

Q. Can the fuel and purchased energy cost subsidy be recognized in the class cost of service study?

A. Yes. First, it is important to recognize that more than 100% of EKPC's fuel and purchased power costs are recovered in base rates. This is because the FAC charge is negative. Therefore, the adjustment that I am proposing should be part of the base rate class cost of service study.

There are two ways to address this mismatch between fuel and purchased power expenses and fuel and purchased power revenues.[7] First, the fuel and purchased energy expenses and revenues can be re-inserted into the cost study. If there is a disparity between actual fuel related energy expenses and revenues for any rate class, it will be reflected in the rate class's revenue requirement deficiency. This disparity will be identified if the fuel and purchased energy related expenses are functionalized into on and off-peak categories and allocated to rate classes on the basis of on and off-peak energy usage. Since the base fuel cost of $0.0264/kWh

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[6] It is important to recognize that each rate class and customer pays an identical price per kWh for fuel and purchased power, despite the fact that fuel and purchased power energy costs are lower during the off-peak hours when a disproportionately larger amount of energy is used by higher load factor customers.

[7] Fuel and purchased power revenues are those used in the computation of the FAC. They consist of the base amount of fuel and the FAC charge itself.

and the FAC is identical for each rate class, there is no recognition of any cost differences between rate classes based on differences in on and off-peak energy usage. By removing these revenues and all of the associated fuel and purchased energy expenses, there is a presumption that there is no impact on any rate class – in other words, the removed revenues and expenses are matched by rate class. Yet, EKPC's own analysis shows that there are differences in each class's on and off-peak energy usage. While the EKPC rates will continue to have a uniform base fuel cost/kWh and FAC, the cost disparity can be calculated and used to adjust the cost of service study revenue deficiency results.

Q. Would you describe the second approach that could be used to adjust for this energy cost vs. energy revenue disparity?

A. The second approach is essentially the same as the first, except the FAC revenue/expense disparity analysis is performed independently and the results simply used to adjust the cost of service rate class revenue deficiencies for each class. This method produces the identical result as the first approach. Since the purposes of the analysis is to determine the amount by which each rate class is underpaying or overpaying base fuel and FAC revenues, the sum of all of these under/over-payments will be equal to "$0".

Q. Have you made an adjustment to the EKPC cost of service study to recognize this cost fuel cost disparity?

A. Yes. The adjustment that I recommend uses the second of the two approaches that I just discussed. It reflects only the differences for each class between allocated cost using a detailed on/off-peak energy allocation and an average annual energy allocation and base fuel/FAC revenues. On a total EKPC basis, these differences sum to zero; however, for each rate class the difference is either positive or negative.

Q. How did you develop your specific adjustment?

A. Table 5 below summarizes the results of the analysis, which is based on EKPC's on/off-peak classification of fuel and purchased power expenses that are included in the cost of service study because the costs are not subject to the FAC.[8]

[8] The EKPC cost study separately allocates non-FAC energy expenses to rate classes by first allocating these expenses to the on and off-peak period and then allocating to rate classes based on each class's share of on and off-peak energy. This is shown on Exhibit RJM-2, page 17 of 17, Schedule G, page 1 of 1 at lines 11-12.

Table 5 Fuel and Purchased Power Revenues vs. Allocated Expenses			
	Base FAC Revenue + FAC Revence	**Allocation of FAC Revenue Requirements**	**Difference: Revenue less Allocated Expense**
Rate B	25,569,591	25,367,635	201,956
Rate C	6,842,133	6,771,805	70,328
Rate E	229,079,029	230,623,327	(1,544,297)
Rate G	11,430,090	11,343,930	86,161
Contract	22,766,779	21,580,927	1,185,852
Total	295,687,623	295,687,623	-

As I noted, the impact on a total EKPC basis sums to zero. The purpose of the adjustment is account for the fuel and purchased energy cost disparity due to rate class differences in on and off-peak energy usage. These differences are then added to the final corrected AED class cost of service study that I presented in my Exhibit SJB-10. Table 6 below presents the adjusted cost of service results for each rate class.

Table 6 Corrected/Adjusted Cost of Service Results					
	Revenue Increase Based on Corrected Cost of Service Study	Fuel Cost vs. Fuel Revenue Disparity Adjustment	Full Cost of Service Results		
				Required Increase	% Incr
Rate B	10,432	(201,956)	$	(191,525)	-0.70%
Rate C	(461,684)	(70,328)	$	(532,012)	-6.71%
Rate E	46,665,137	1,544,297	$	48,209,434	14.08%
Rate G	910,629	(86,161)	$	824,469	7.61%
Contract	1,610,037	(1,185,852)	$	424,185	1.79%
Steam	304,231		$	304,231	6.74%
Rate TGP	-		$	-	0.00%
Total	49,038,782		$	49,038,782	11.62%

III. ALLOCATION OF THE REVENUE INCREASE TO RATE CLASSES

Q. EKPC proposes increases in this case based on its class cost of service study results, adjusted to reflect a lower overall revenue increase of $43 million, and a revenue increase cap of 8% for any rate class. Based on your corrected class cost of service study results, what is your recommended set of rate class revenue increases?

A. Based on the corrected cost of service results that I presented in Table 6, I recommend that: **1) Rate B, Rate C and Rate TGP receive no rate increase; 2) the Contract**

Class (Nucor) receive no more than a cost-based rate increase; and 3) Rate E, Rate G and the Steam Class receive a uniform percentage increase. Table 7 presents these increases, which are based on EKPC's requested overall revenue increase of $42,990,251.

Table 7
Recommended Rate Class Revenue Increases

	Proposed Rate Increase	
	$	%
Rate B	$ -	0.00%
Rate C	$ -	0.00%
Rate E	$ 40,363,730	6.08%
Rate G	$ 1,550,913	6.08%
Contract	$ 424,185	1.00%
Steam	$ 651,349	6.08%
Rate TGP	$ -	0.00%
Total	$ 42,990,177	5.20%

Q. In the likely event that the Commission authorizes a revenue increase for EKPC that is lower than the amount requested, how would your proposal work?

A. I would recommend that the dollar increases that I presented in Table 7 be scaled-back on a uniform percentage basis for each rate class to reflect the approved overall revenue increase.

Q. In addition to the cost of service results, why are you proposing no more than a cost based increase for Nucor?

A. Setting Nucor's rates at the corrected cost of service in this case is a reasonable and prudent policy that the Commission should follow.

As discussed in the testimony of Nucor witness Barry Kornstein, Nucor provides significant economic benefits to Kentucky in terms of jobs, tax revenues and general economic activity. Mr. Kornstein concluded that the Kentucky state-wide economic impacts from the existing Nucor plant, the galvanizing line and the new expansion will be: 1) 642 direct employees with total annual labor income of $75.5 million; 2) 3,317 direct, indirect and induced jobs with total annual labor income of $250 million; 3) total annual value added (Kentucky gross domestic product) of $752.2 million and 4) annual state government revenue of $15.4 million.

Q. Why is it an appropriate regulatory policy to limit the subsidy reductions to only large industrial rate classes?

A. While moving all rates towards cost of service is an appropriate regulatory policy, there are a number of reasons to focus on the subsidies paid by large industrial customers. Energy costs can make or break an industrial customer. Whereas energy costs are just another expense for most businesses. That is why there are no steel plants in California, but there are plenty of restaurants and retailers.

Q. How should the competitiveness of the manufacturing sector be factored into the Commission's decision?

A. Electric rates are a significant factor in the competitiveness of manufacturers that must compete regionally, nationally, and internationally. It is critically important to recognize the impact of ever-increasing electric rates on the ability of large manufacturing customers to continue to operate and to attract new, higher paying manufacturing businesses. This is especially true given increasingly strict environmental rules on Kentucky's predominately coal generation fleet and the mounting national and international pressure to reduce CO2 emissions.

Q. Does Kentucky law support the consideration of non-cost factors like economic development when allocating utility costs among the customer classes?

A. Yes, while not offering a legal opinion or interpretation, from a non-lawyer perspective, KRS 278.030(3) provides such support. KRS 278.030(3) specifically states that utilities may take into account the "nature" and "purpose" for which utility service is used when setting rates and classifications of service. That Section, entitled Rates, classifications and service of utilities to be just and reasonable states:

> Every utility may employ in the conduct of its business suitable and reasonable classifications of its service, patrons and rates. The classifications may, in any proper case, take into account <u>the nature of the use</u>, the quality used, the quantity used, the time when used, <u>the purpose for which used</u>, and any other reasonable consideration. (emphasis added)

The Kentucky General Assembly has not specifically made cost of service a criterion in setting rates. In fact, cost of service is not mentioned in the relevant statutes. But the General Assembly has specifically authorized the consideration of non-cost factors when setting rates, establishing that the “purpose” for which a customer uses power and the “nature” of use may justify different rate treatment. Given this language it would be appropriate for the Commission to consider economic development principles when determining a just and reasonable rate allocation in this case.

Energy-intensive large manufacturing customers use a relatively large amount of power in order to convert raw materials into a finished product. Such processes rely on electric power as an input into the manufacturing process. Industrial customers that compete in regional, national and international markets are greatly affected by increases in the price of power. Many industrial manufacturers, including Nucor Steel, located in Kentucky precisely because of historically low electric rates. But because Kentucky’s generation mix is so heavily reliant on coal, that competitive advantage could easily turn into a disadvantage as stricter environmental regulations and carbon pricing policies develop.

In contrast, commercial customers primarily use electricity for lighting and cooling. These uses typically represent a relatively small portion of that customers’ total expenses. Additionally, a commercial customer in Kentucky faces its primary competition from other local retailers in the same electric service territory. An increase or decrease in power rates will not confer an advantage or disadvantage on any single competitor because they are all served by the same utility at presumably the same rate.

Q. Does State policy recognize the unique importance of the industrial manufacturing sector to the Kentucky economy?

A. Yes. The Kentucky Cabinet for Economic Development currently cites low electricity rates as a primary advantage for Kentucky's economy. The Cabinet states:

> Kentucky features some of the lowest industrial electricity rates in the nation, one of many factors helping companies maintain a healthy bottom line in the state. The state ranked first nationally for cost of doing business in CNBC's 2019 list of America's Top States for Business, which considers each state's tax climate, available incentives for businesses, utility costs, the cost of wages and rental costs for office and industrial space.[9]

Governor Bashear's administration has reaffirmed the importance of fostering policies that are designed to attract and retain manufacturing in the Commonwealth. In October of 2020, Gov. Bashear stated that we must "recognize how profound an impact manufacturing has on Kentucky's economy, its communities and its families…Manufacturers in Kentucky employ about 260,000 people, full-time." He noted that Kentucky's manufacturing base far outstrips the national average,

[9] https://ced.ky.gov/Newsroom/Article.aspx?x=20201002_manufacturing_excellence.

with 13% of the Commonwealth's workforce employed in manufacturing versus 8.5% nationally.[10]

IV. INTERRUPTIBLE RATES

Q. Would you discuss EKPC's proposed interruptible rate applicable to Nucor Gallatin (Contract class)?

A. The Contract class has two interruptible rates, each of which has a different interruptible notice period - either 10-minute notice or 90-minute notice. All load served under the 10-minute notice interruptible rate must be completely curtailed within 10 minutes of receiving a notification from EKPC. Effectively, a 10-miniute notice interruptible load provides the system with a generation resource that is comparable to a combustion turbine that can be started and brought on-line in 10 minutes. Not all combustion turbines can be started within 10 minutes, only so-called quick-start CTs such as an areo-derivative CT. Interruptible load taking service under the 90-minute notice interruptible rate must be curtailed within 90 minutes of notification. Since the 10-minute notice interruptible load provides a greater resource value to the system, the corresponding credit is greater than the 90-minute notice credit.

[10] https://kentucky.gov/Pages/Activity-stream.aspx?n=GovernorBeshear&prId=399.

Q. How does EKPC treat interruptible load in its class cost of service study?

A. Consistent with the approaches used by LG&E and KU, EKPC treats interruptible load as a generation resource equivalent to a combustion turbine. This is consistent with how PJM treats Demand Response load that is bid into the Base Residual Auction ("BRA") or used as a capacity resource in the case of Kentucky Power Company, which is a PJM Fixed Resource Requirement ("FRR") participant. For ratemaking in this rate case, EKPC removes the interruptible credit from customer class revenues (removing the credit increases these revenues), but then fully allocates costs to the total load of each rate class, including interruptible load that occurred during the test year.

Q. How is interruptible load utilized by EKPC for PJM and system planning purposes?

A. Interruptible load plays two roles in EKPC's planning. EKPC must include its interruptible load in its PJM Peak Load Obligation, which is used to determine EKPC's capacity obligation under the Reliability Pricing Model ("RPM"). As a participant in the PJM Base Residual Auction ("BRA"), EKPC is charged a Locational Reliability Charge ("LRC") for all of its load based on the PJM RPM rate applicable to EKPC's zone. At the same time, EKPC sells its interruptible load into the PJM Demand Response ("DR") program, receiving offsetting revenues based on the RPM rate.

The second role played by interruptible load is related to EKPC's actual resource planning. Based on the EKPC 2019 IRP, EKPC plans generation resources based on meeting its winter peak load.[11] For capacity planning purposes, this winter peak load obligation excludes interruptible load.[12] This means that EKPC does not plan capacity to serve the interruptible load, nor does it incur costs associated with providing a reserve margin for this load.

Q. Do you have any concerns about the EKPC interruptible credits in this case?

A. Yes, I believe that EKPC understates the value of interruptible load provided pursuant to the 10-minute notice Contract class (Nucor Gallatin) rate. EKPC proposes to keep the current 10-minute notice interruptible credit of $6.22/kW-month at its current level, which was first set in EKPC's 2010 rate case. In the Commission's recent decision in Kentucky Power Company's Net Metering case, the Commission found that the appropriate avoided generation capacity cost was the PJM Net CONE rate of $7.57/kW-month.[13] Both EKPC and KPCo are PJM members and are in CONE Area

[11] *See* EKPC's 2019 Integrated Resource Plan of April 1, 2019 (Case No. 2019-00096) at page 4 ("Therefore, EKPC plans to meet its winter peak load obligations with secured resources, and not be solely dependent on the market, thereby fulfilling a policy espoused by the Commission in prior cases").
[12] *See* Staff Report in EKPC's IRP Case, Case No. 2019-00096 at Footnote No. 90 on page 24 ("…In order to forecast future capacity needs, the Peak Demand forecasts in Table 8-6 reflect the addition of new future DSM programs <u>and the exclusion of interruptible power</u>." (emphasis added).
[13] Net Metering Order in Case No. 2020-00174 at p-29. May 14, 2021.

3 for purposes of calculating Net CONE. I recommend that the Contract class 10-minute interruptible credit be increased up to $7.57/kW-month to reflect a current measure of avoided capacity cost for EKPC.

The 10-minute interruptible credit should not exceed the firm demand charge. Even if the 10-minute interruptible credit fully off-sets the firm demand charge this interruptible load will contribute to EKPC's fixed costs in three ways. First, Nucor's on-peak and off-peak energy charges are significantly above EKPC's variable cost of production. This means that the energy charge recovers demand costs. Second, the 10-minute interruptible load pays the full environmental surcharge, including the fixed cost portion. Finally, EKPC receives revenue from selling Nucor's 10-minute interruptible load into the PJM capacity market.

Q. Are you recommending that EKPC's other interruptible credits be increased to Net CONE?

A. No. Interruptible load subject to a 10-minute notice provides a similar reliability benefit to a quick start combustion turbine, while EKPC's other interruptible load is only subject to a 30-minute notice (Rate D) or 90-minute notice, which provide a reduced level of reliability compared to a 10-minute notice.

Q. Does that complete your testimony?

A. Yes.

AFFIDAVIT

STATE OF GEORGIA)

COUNTY OF FULTON)

STEPHEN J. BARON, being duly sworn, deposes and states: that the attached is his sworn testimony and that the statements contained are true and correct to the best of his knowledge, information and belief.

Stephen J. Baron

Stephen J. Baron

Sworn to and subscribed before me on this
28th day of June 2021.

Jessica K. Inman

Notary Public

JESSICA K INMAN
MY COMMISSION EXPIRES
NOTARY
PUBLIC
JULY 31, 2023
CHEROKEE COUNTY, GEORGIA

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF:

THE ELECTRONIC APPLICATION OF	)	
EAST KENTUCKY POWER COOPERATIVE, INC.	)	
FOR A GENERAL ADJUSTMENT OF RATES,	)	**Case No. 2021-00103**
APPROVAL OF DEPRECIATION STUDY,	)	
AMORTIZATION OF CERTAIN REGULATORY	)	
ASSETS, AND OTHER RELIEF	)	

EXHIBITS

OF

STEPHEN J. BARON

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF:

THE ELECTRONIC APPLICATION OF	**)**	
EAST KENTUCKY POWER COOPERATIVE, INC.	**)**	
FOR A GENERAL ADJUSTMENT OF RATES,	**)**	**Case No. 2021-00103**
APPROVAL OF DEPRECIATION STUDY,	**)**	
AMORTIZATION OF CERTAIN REGULATORY	**)**	
ASSETS, AND OTHER RELIEF	**)**	

EXHIBIT__(SJB-1)

OF

STEPHEN J. BARON

Professional Qualifications

Of

Stephen J. Baron

Mr. Baron graduated from the University of Florida in l972 with a B.A. degree with high honors in Political Science and significant coursework in Mathematics and Computer Science. In 1974, he received a Master of Arts Degree in Economics, also from the University of Florida. His areas of specialization were econometrics, statistics, and public utility economics. His thesis concerned the development of an econometric model to forecast electricity sales in the State of Florida, for which he received a grant from the Public Utility Research Center of the University of Florida. In addition, he has advanced study and coursework in time series analysis and dynamic model building.

Mr. Baron has more than forty years of experience in the electric utility industry in the areas of cost and rate analysis, forecasting, planning, and economic analysis.

Following the completion of my graduate work in economics, he joined the staff of the Florida Public Service Commission in August of 1974 as a Rate Economist. His responsibilities included the analysis of rate cases for electric, telephone, and gas utilities, as well as the preparation of cross-examination material and the preparation of staff recommendations.

In December 1975, he joined the Utility Rate Consulting Division of Ebasco Services, Inc.

as an Associate Consultant. In the seven years he worked for Ebasco, he received successive promotions, ultimately to the position of Vice President of Energy Management Services of Ebasco Business Consulting Company. His responsibilities included the management of a staff of consultants engaged in providing services in the areas of econometric modeling, load and energy forecasting, production cost modeling, planning, cost-of-service analysis, cogeneration, and load management.

He joined the public accounting firm of Coopers & Lybrand in 1982 as a Manager of the Atlanta Office of the Utility Regulatory and Advisory Services Group. In this capacity he was responsible for the operation and management of the Atlanta office. His duties included the technical and administrative supervision of the staff, budgeting, recruiting, and marketing as well as project management on client engagements. At Coopers & Lybrand, he specialized in utility cost analysis, forecasting, load analysis, economic analysis, and planning.

In January 1984, he joined the consulting firm of Kennedy and Associates as a Vice President and Principal. Mr. Baron became President of the firm in January 1991.

He has presented numerous papers and published an article entitled "How to Rate Load Management Programs" in the March 1979 edition of "Electrical World." His article on "Standby Electric Rates" was published in the November 8, 1984 issue of "Public Utilities Fortnightly." In February of 1984, he completed a detailed analysis entitled "Load Data

Transfer Techniques" on behalf of the Electric Power Research Institute, which published the study.

Mr. Baron has presented testimony as an expert witness in Arizona, Arkansas, Colorado, Connecticut, Florida, Georgia, Indiana, Kentucky, Louisiana, Maine, Michigan, Minnesota, Maryland, Missouri, Montana, New Jersey, New Mexico, New York, North Carolina, South Carolina, Ohio, Pennsylvania, Tennessee, Texas, Utah, Virginia, West Virginia, Wisconsin, Wyoming, the Federal Energy Regulatory Commission and in United States Bankruptcy Court. A list of his specific regulatory appearances follows.

Expert Testimony Appearances
of
Stephen J. Baron
As of June 2021

Date	Case	Jurisdict.	Party	Utility	Subject
4/81	203(B)	KY	Louisville Gas & Electric Co.	Louisville Gas & Electric Co.	Cost-of-service.
4/81	ER-81-42	MO	Kansas City Power & Light Co.	Kansas City Power & Light Co.	Forecasting.
6/81	U-1933	AZ	Arizona Corporation Commission	Tucson Electric Co.	Forecasting planning.
2/84	8924	KY	Airco Carbide	Louisville Gas & Electric Co.	Revenue requirements, cost-of-service, forecasting, weather normalization.
3/84	84-038-U	AR	Arkansas Electric Energy Consumers	Arkansas Power & Light Co.	Excess capacity, cost-of-service, rate design.
5/84	830470-EI	FL	Florida Industrial Power Users' Group	Florida Power Corp.	Allocation of fixed costs, load and capacity balance, and reserve margin. Diversification of utility.
10/84	84-199-U	AR	Arkansas Electric Energy Consumers	Arkansas Power and Light Co.	Cost allocation and rate design.
11/84	R-842651	PA	Lehigh Valley Power Committee	Pennsylvania Power & Light Co.	Interruptible rates, excess capacity, and phase-in.
1/85	85-65	ME	Airco Industrial Gases	Central Maine Power Co.	Interruptible rate design.
2/85	I-840381	PA	Philadelphia Area Industrial Energy Users' Group	Philadelphia Electric Co.	Load and energy forecast.
3/85	9243	KY	Alcan Aluminum Corp., et al.	Louisville Gas & Electric Co.	Economics of completing fossil generating unit.
3/85	3498-U	GA	Attorney General	Georgia Power Co.	Load and energy forecasting, generation planning economics.
3/85	R-842632	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Generation planning economics, prudence of a pumped storage hydro unit.
5/85	84-249	AR	Arkansas Electric Energy Consumers	Arkansas Power & Light Co.	Cost-of-service, rate design return multipliers.
5/85		City of Santa Clara	Chamber of Commerce	Santa Clara Municipal	Cost-of-service, rate design.
6/85	84-768-E-42T	WV	West Virginia Industrial Intervenors	Monongahela Power Co.	Generation planning economics, prudence of a pumped storage hydro unit.

Expert Testimony Appearances
of
Stephen J. Baron
As of June 2021

Date	Case	Jurisdict.	Party	Utility	Subject
6/85	E-7 Sub 391	NC	Carolina Industrials (CIGFUR III)	Duke Power Co.	Cost-of-service, rate design, interruptible rate design.
7/85	29046	NY	Industrial Energy Users Association	Orange and Rockland Utilities	Cost-of-service, rate design.
10/85	85-043-U	AR	Arkansas Gas Consumers	Arkla, Inc.	Regulatory policy, gas cost-of-service, rate design.
10/85	85-63	ME	Airco Industrial Gases	Central Maine Power Co.	Feasibility of interruptible rates, avoided cost.
2/85	ER-8507698	NJ	Air Products and Chemicals	Jersey Central Power & Light Co.	Rate design.
3/85	R-850220	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Optimal reserve, prudence, off-system sales guarantee plan.
2/86	R-850220	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Optimal reserve margins, prudence, off-system sales guarantee plan.
3/86	85-299U	AR	Arkansas Electric Energy Consumers	Arkansas Power & Light Co.	Cost-of-service, rate design, revenue distribution.
3/86	85-726-EL-AIR	OH	Industrial Electric Consumers Group	Ohio Power Co.	Cost-of-service, rate design, interruptible rates.
5/86	86-081-E-GI	WV	West Virginia Energy Users Group	Monongahela Power Co.	Generation planning economics, prudence of a pumped storage hydro unit.
8/86	E-7 Sub 408	NC	Carolina Industrial Energy Consumers	Duke Power Co.	Cost-of-service, rate design, interruptible rates.
10/86	U-17378	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Excess capacity, economic analysis of purchased power.
12/86	38063	IN	Industrial Energy Consumers	Indiana & Michigan Power Co.	Interruptible rates.
3/87	EL-86-53-001 EL-86-57-001	Federal Energy Regulatory Commission (FERC)	Louisiana Public Service Commission Staff	Gulf States Utilities, Southern Co.	Cost/benefit analysis of unit power sales contract.
4/87	U-17282	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Load forecasting and imprudence damages, River Bend Nuclear unit.

Expert Testimony Appearances
of
Stephen J. Baron
As of June 2021

Date	Case	Jurisdict.	Party	Utility	Subject
5/87	87-023-E-C	WV	Airco Industrial Gases	Monongahela Power Co.	Interruptible rates.
5/87	87-072-E-G1	WV	West Virginia Energy Users' Group	Monongahela Power Co.	Analyze Mon Power's fuel filing and examine the reasonableness of MP's claims.
5/87	86-524-E-SC	WV	West Virginia Energy Users' Group	Monongahela Power Co.	Economic dispatching of pumped storage hydro unit.
5/87	9781	KY	Kentucky Industrial Energy Consumers	Louisville Gas & Electric Co.	Analysis of impact of 1986 Tax Reform Act.
6/87	3673-U	GA	Georgia Public Service Commission	Georgia Power Co.	Economic prudence, evaluation of Vogtle nuclear unit - load forecasting, planning.
6/87	U-17282	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Phase-in plan for River Bend Nuclear unit.
7/87	85-10-22	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power Co.	Methodology for refunding rate moderation fund.
8/87	3673-U	GA	Georgia Public Service Commission	Georgia Power Co.	Test year sales and revenue forecast.
9/87	R-850220	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Excess capacity, reliability of generating system.
10/87	R-870651	PA	Duquesne Industrial Intervenors	Duquesne Light Co.	Interruptible rate, cost-of-service, revenue allocation, rate design.
10/87	I-860025	PA	Pennsylvania Industrial Intervenors		Proposed rules for cogeneration, avoided cost, rate recovery.
10/87	E-015/GR-87-223	MN	Taconite Intervenors	Minnesota Power & Light Co.	Excess capacity, power and cost-of-service, rate design.
10/87	8702-EI	FL	Occidental Chemical Corp.	Florida Power Corp.	Revenue forecasting, weather normalization.
12/87	87-07-01	CT	Connecticut Industrial Energy Consumers	Connecticut Light Power Co.	Excess capacity, nuclear plant phase-in.
3/88	10064	KY	Kentucky Industrial Energy Consumers	Louisville Gas & Electric Co.	Revenue forecast, weather normalization rate treatment of cancelled plant.
3/88	87-183-TF	AR	Arkansas Electric Consumers	Arkansas Power & Light Co.	Standby/backup electric rates.

Expert Testimony Appearances
of
Stephen J. Baron
As of June 2021

Date	Case	Jurisdict.	Party	Utility	Subject
5/88	870171C001	PA	GPU Industrial Intervenors	Metropolitan Edison Co.	Cogeneration deferral mechanism, modification of energy cost recovery (ECR).
6/88	870172C005	PA	GPU Industrial Intervenors	Pennsylvania Electric Co.	Cogeneration deferral mechanism, modification of energy cost recovery (ECR).
7/88	88-171-EL-AIR 88-170-EL-AIR Interim Rate Case	OH	Industrial Energy Consumers	Cleveland Electric/ Toledo Edison	Financial analysis/need for interim rate relief.
7/88	Appeal of PSC Docket U-17282	19th Judicial Circuit Court of Louisiana	Louisiana Public Service Commission	Gulf States Utilities	Load forecasting, imprudence damages.
11/88	R-880989	PA	United States Steel	Carnegie Gas	Gas cost-of-service, rate design.
11/88	88-171-EL-AIR 88-170-EL-AIR	OH	Industrial Energy Consumers	Cleveland Electric/ Toledo Edison. General Rate Case.	Weather normalization of peak loads, excess capacity, regulatory policy.
3/89	870216/283 284/286	PA	Armco Advanced Materials Corp., Allegheny Ludlum Corp.	West Penn Power Co.	Calculated avoided capacity, recovery of capacity payments.
8/89	8555	TX	Occidental Chemical Corp.	Houston Lighting & Power Co.	Cost-of-service, rate design.
8/89	3840-U	GA	Georgia Public Service Commission	Georgia Power Co.	Revenue forecasting, weather normalization.
9/89	2087	NM	Attorney General of New Mexico	Public Service Co. of New Mexico	Prudence - Palo Verde Nuclear Units 1, 2 and 3, load fore-casting.
10/89	2262	NM	New Mexico Industrial Energy Consumers	Public Service Co. of New Mexico	Fuel adjustment clause, off-system sales, cost-of-service, rate design, marginal cost.
11/89	38728	IN	Industrial Consumers for Fair Utility Rates	Indiana Michigan Power Co.	Excess capacity, capacity equalization, jurisdictional cost allocation, rate design, interruptible rates.
1/90	U-17282	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Jurisdictional cost allocation, O&M expense analysis.

Expert Testimony Appearances
of
Stephen J. Baron
As of June 2021

Date	Case	Jurisdict.	Party	Utility	Subject
5/90	890366	PA	GPU Industrial Intervenors	Metropolitan Edison Co.	Non-utility generator cost recovery.
6/90	R-901609	PA	Armco Advanced Materials Corp., Allegheny Ludlum Corp.	West Penn Power Co.	Allocation of QF demand charges in the fuel cost, cost-of-service, rate design.
9/90	8278	MD	Maryland Industrial Group	Baltimore Gas & Electric Co.	Cost-of-service, rate design, revenue allocation.
12/90	U-9346 Rebuttal	MI	Association of Businesses Advocating Tariff Equity	Consumers Power Co.	Demand-side management, environmental externalities.
12/90	U-17282 Phase IV	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Revenue requirements, jurisdictional allocation.
12/90	90-205	ME	Airco Industrial Gases	Central Maine Power Co.	Investigation into interruptible service and rates.
1/91	90-12-03 Interim	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power Co.	Interim rate relief, financial analysis, class revenue allocation.
5/91	90-12-03 Phase II	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power Co.	Revenue requirements, cost-of-service, rate design, demand-side management.
8/91	E-7, SUB 487	NC	North Carolina Industrial Energy Consumers	Duke Power Co.	Revenue requirements, cost allocation, rate design, demand-side management.
8/91	8341 Phase I	MD	Westvaco Corp.	Potomac Edison Co.	Cost allocation, rate design, 1990 Clean Air Act Amendments.
8/91	91-372 EL-UNC	OH	Armco Steel Co., L.P.	Cincinnati Gas & Electric Co.	Economic analysis of cogeneration, avoid cost rate.
9/91	P-910511 P-910512	PA	Allegheny Ludlum Corp., Armco Advanced Materials Co., The West Penn Power Industrial Users' Group	West Penn Power Co.	Economic analysis of proposed CWIP Rider for 1990 Clean Air Act Amendments expenditures.
9/91	91-231 -E-NC	WV	West Virginia Energy Users' Group	Monongahela Power Co.	Economic analysis of proposed CWIP Rider for 1990 Clean Air Act Amendments expenditures.
10/91	8341 - Phase II	MD	Westvaco Corp.	Potomac Edison Co.	Economic analysis of proposed CWIP Rider for 1990 Clean Air

Expert Testimony Appearances
of
Stephen J. Baron
As of June 2021

Date	Case	Jurisdict.	Party	Utility	Subject
					Act Amendments expenditures.
10/91	U-17282	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Results of comprehensive management audit.
Note: No testimony was prefiled on this.					
11/91	U-17949 Subdocket A	LA	Louisiana Public Service Commission Staff	South Central Bell Telephone Co. and proposed merger with Southern Bell Telephone Co.	Analysis of South Central Bell's restructuring and
12/91	91-410-EL-AIR	OH	Armco Steel Co., Air Products & Chemicals, Inc.	Cincinnati Gas & Electric Co.	Rate design, interruptible rates.
12/91	P-880286	PA	Armco Advanced Materials Corp., Allegheny Ludlum Corp.	West Penn Power Co.	Evaluation of appropriate avoided capacity costs - QF projects.
1/92	C-913424	PA	Duquesne Interruptible Complainants	Duquesne Light Co.	Industrial interruptible rate.
6/92	92-02-19	CT	Connecticut Industrial Energy Consumers	Yankee Gas Co.	Rate design.
8/92	2437	NM	New Mexico Industrial Intervenors	Public Service Co. of New Mexico	Cost-of-service.
8/92	R-00922314	PA	GPU Industrial Intervenors	Metropolitan Edison Co.	Cost-of-service, rate design, energy cost rate.
9/92	39314	ID	Industrial Consumers for Fair Utility Rates	Indiana Michigan Power Co.	Cost-of-service, rate design, energy cost rate, rate treatment.
10/92	M-00920312 C-007	PA	The GPU Industrial Intervenors	Pennsylvania Electric Co.	Cost-of-service, rate design, energy cost rate, rate treatment.
12/92	U-17949	LA	Louisiana Public Service Commission Staff	South Central Bell Co.	Management audit.
12/92	R-00922378	PA	Armco Advanced Materials Co. The WPP Industrial Intervenors	West Penn Power Co.	Cost-of-service, rate design, energy cost rate, SO_2 allowance rate treatment.
1/93	8487	MD	The Maryland Industrial Group	Baltimore Gas & Electric Co.	Electric cost-of-service and rate design, gas rate design (flexible rates).
2/93	E002/GR-92-1185	MN	North Star Steel Co. Praxair, Inc.	Northern States Power Co.	Interruptible rates.

Expert Testimony Appearances
of
Stephen J. Baron
As of June 2021

Date	Case	Jurisdict.	Party	Utility	Subject
4/93	EC92 21000 ER92-806-000 (Rebuttal)	Federal Energy Regulatory Commission	Louisiana Public Service Commission Staff	Gulf States Utilities/Entergy agreement.	Merger of GSU into Entergy System; impact on system
7/93	93-0114-E-C	WV	Airco Gases	Monongahela Power Co.	Interruptible rates.
8/93	930759-EG	FL	Florida Industrial Power Users' Group	Generic - Electric Utilities	Cost recovery and allocation of DSM costs.
9/93	M-009 30406	PA	Lehigh Valley Power Committee	Pennsylvania Power & Light Co.	Ratemaking treatment of off-system sales revenues.
11/93	346	KY	Kentucky Industrial Utility Customers	Generic - Gas Utilities	Allocation of gas pipeline transition costs - FERC Order 636.
12/93	U-17735	LA	Louisiana Public Service Commission Staff	Cajun Electric Power Cooperative	Nuclear plant prudence, forecasting, excess capacity.
4/94	E-015/ GR-94-001	MN	Large Power Intervenors	Minnesota Power Co.	Cost allocation, rate design, rate phase-in plan.
5/94	U-20178	LA	Louisiana Public Service Commission	Louisiana Power & Light Co.	Analysis of least cost integrated resource plan and demand-side management program.
7/94	R-00942986	PA	Armco, Inc.; West Penn Power Industrial Intervenors	West Penn Power Co.	Cost-of-service, allocation of rate increase, rate design, emission allowance sales, and operations and maintenance expense.
7/94	94-0035-E-42T	WV	West Virginia Energy Users Group	Monongahela Power Co.	Cost-of-service, allocation of rate increase, and rate design.
8/94	EC94 13-000	Federal Energy Regulatory Commission	Louisiana Public Service Commission	Gulf States Utilities/Entergy	Analysis of extended reserve shutdown units and violation of system agreement by Entergy.
9/94	R-00943 081 R-00943 081C0001	PA	Lehigh Valley Power Committee	Pennsylvania Public Utility Commission	Analysis of interruptible rate terms and conditions, availability.
9/94	U-17735	LA	Louisiana Public Service Commission	Cajun Electric Power Cooperative	Evaluation of appropriate avoided cost rate.
9/94	U-19904	LA	Louisiana Public Service Commission	Gulf States Utilities	Revenue requirements.

Expert Testimony Appearances
of
Stephen J. Baron
As of June 2021

Date	Case	Jurisdict.	Party	Utility	Subject
10/94	5258-U	GA	Georgia Public Service Commission	Southern Bell Telephone & Telegraph Co.	Proposals to address competition in telecommunication markets.
11/94	EC94-7-000 ER94-898-000	FERC	Louisiana Public Service Commission	El Paso Electric and Central and Southwest	Merger economics, transmission equalization hold harmless proposals.
2/95	941-430EG	CO	CF&I Steel, L.P.	Public Service Company of Colorado	Interruptible rates, cost-of-service.
4/95	R-00943271	PA	PP&L Industrial Customer Alliance	Pennsylvania Power & Light Co.	Cost-of-service, allocation of rate increase, rate design, interruptible rates.
6/95	C-00913424 C-00946104	PA	Duquesne Interruptible Complainants	Duquesne Light Co.	Interruptible rates.
8/95	ER95-112 -000	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Open Access Transmission Tariffs - Wholesale.
10/95	U-21485	LA	Louisiana Public Service Commission	Gulf States Utilities Company	Nuclear decommissioning, revenue requirements, capital structure.
10/95	ER95-1042 -000	FERC	Louisiana Public Service Commission	System Energy Resources, Inc.	Nuclear decommissioning, revenue requirements.
10/95	U-21485	LA	Louisiana Public Service Commission	Gulf States Utilities Co.	Nuclear decommissioning and cost of debt capital, capital structure.
11/95	I-940032	PA	Industrial Energy Consumers of Pennsylvania	State-wide - all utilities	Retail competition issues.
7/96	U-21496	LA	Louisiana Public Service Commission	Central Louisiana Electric Co.	Revenue requirement analysis.
7/96	8725	MD	Maryland Industrial Group	Baltimore Gas & Elec. Co., Potomac Elec. Power Co., Constellation Energy Co.	Ratemaking issues associated with a Merger.
8/96	U-17735	LA	Louisiana Public Service Commission	Cajun Electric Power Cooperative	Revenue requirements.
9/96	U-22092	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Decommissioning, weather normalization, capital structure.
2/97	R-973877	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy Co.	Competitive restructuring policy issues, stranded cost, transition charges.

Expert Testimony Appearances
of
Stephen J. Baron
As of June 2021

Date	Case	Jurisdict.	Party	Utility	Subject
6/97	Civil Action No. 94-11474	US Bankruptcy Court Middle District of Louisiana	Louisiana Public Service Commission	Cajun Electric Power Cooperative	Confirmation of reorganization plan; analysis of rate paths produced by competing plans.
6/97	R-973953	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy Co.	Retail competition issues, rate unbundling, stranded cost analysis.
6/97	8738	MD	Maryland Industrial Group	Generic	Retail competition issues
7/97	R-973954	PA	PP&L Industrial Customer Alliance	Pennsylvania Power & Light Co.	Retail competition issues, rate unbundling, stranded cost analysis.
10/97	97-204	KY	Alcan Aluminum Corp. Southwire Co.	Big River Electric Corp.	Analysis of cost of service issues - Big Rivers Restructuring Plan
10/97	R-974008	PA	Metropolitan Edison Industrial Users	Metropolitan Edison Co.	Retail competition issues, rate unbundling, stranded cost analysis.
10/97	R-974009	PA	Pennsylvania Electric Industrial Customer	Pennsylvania Electric Co.	Retail competition issues, rate unbundling, stranded cost analysis.
11/97	U-22491	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Decommissioning, weather normalization, capital structure.
11/97	P-971265	PA	Philadelphia Area Industrial Energy Users Group	Enron Energy Services Power, Inc./ PECO Energy	Analysis of Retail Restructuring Proposal.
12/97	R-973981	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Retail competition issues, rate unbundling, stranded cost analysis.
12/97	R-974104	PA	Duquesne Industrial Intervenors	Duquesne Light Co.	Retail competition issues, rate unbundling, stranded cost analysis.
3/98	U-22092 (Allocated Stranded Cost Issues)	LA	Louisiana Public Service Commission	Gulf States Utilities Co.	Retail competition, stranded cost quantification.
3/98	U-22092	LA	Louisiana Public Service Commission	Gulf States Utilities, Inc.	Stranded cost quantification, restructuring issues.
9/98	U-17735	LA	Louisiana Public Service Commission	Cajun Electric Power Cooperative, Inc.	Revenue requirements analysis, weather normalization.

Expert Testimony Appearances
of
Stephen J. Baron
As of June 2021

Date	Case	Jurisdict.	Party	Utility	Subject
12/98	8794	MD	Maryland Industrial Group and Millennium Inorganic Chemicals Inc.	Baltimore Gas and Electric Co.	Electric utility restructuring, stranded cost recovery, rate unbundling.
12/98	U-23358	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Nuclear decommissioning, weather normalization, Entergy System Agreement.
5/99 (Cross-Answering Testimony)	EC-98-40-000	FERC	Louisiana Public Service Commission	American Electric Power Co. & Central South West Corp.	Merger issues related to market power mitigation proposals.
5/99 (Response Testimony)	98-426	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas & Electric Co.	Performance based regulation, settlement proposal issues, cross-subsidies between electric. And gas services.
6/99	98-0452	WV	West Virginia Energy Users Group	Appalachian Power, Monongahela Power, & Potomac Edison Companies	Electric utility restructuring, stranded cost recovery, rate unbundling.
7/99	99-03-35	CT	Connecticut Industrial \Energy Consumers	United Illuminating Company	Electric utility restructuring, stranded cost recovery, rate unbundling.
7/99	Adversary Proceeding No. 98-1065	U.S. Bankruptcy Court	Louisiana Public Service Commission	Cajun Electric Power Cooperative	Motion to dissolve preliminary injunction.
7/99	99-03-06	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power Co.	Electric utility restructuring, stranded cost recovery, rate unbundling.
10/99	U-24182	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Nuclear decommissioning, weather normalization, Entergy System Agreement.
12/99	U-17735	LA	Louisiana Public Service Commission	Cajun Electric Power Cooperative, Inc.	Ananlysi of Proposed Contract Rates, Market Rates.
03/00	U-17735	LA	Louisiana Public Service Commission	Cajun Electric Power Cooperative, Inc.	Evaluation of Cooperative Power Contract Elections
03/00	99-1658-EL-ETP	OH	AK Steel Corporation	Cincinnati Gas & Electric Co.	Electric utility restructuring, stranded cost recovery, rate Unbundling.

Expert Testimony Appearances
of
Stephen J. Baron
As of June 2021

Date	Case	Jurisdict.	Party	Utility	Subject
08/00	98-0452 E-GI	WV	West Virginia Energy Users Group	Appalachian Power Co. American Electric Co.	Electric utility restructuring rate unbundling.
08/00	00-1050 E-T 00-1051-E-T	WV	West Virginia Energy Users Group	Mon Power Co. Potomac Edison Co.	Electric utility restructuring rate unbundling.
09/00	00-1178-E-T	WV	West Virginia Energy Users Group	Appalachian Power Co. Wheeling Power Co.	Electric utility restructuring rate unbundling
10/00	SOAH 473-00-1020 PUC 2234	TX	The Dallas-Fort Worth Hospital Council and The Coalition of Independent Colleges And Universities	TXU, Inc.	Electric utility restructuring rate unbundling.
12/00	U-24993	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Nuclear decommissioning, revenue requirements.
12/00	EL00-66-000 & ER00-2854 EL95-33-002	LA	Louisiana Public Service Commission	Entergy Services Inc.	Inter-Company System Agreement: Modifications for retail competition, interruptible load.
04/01	U-21453, U-20925, U-22092 (Subdocket B) Addressing Contested Issues	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Jurisdictional Business Separation - Texas Restructuring Plan
10/01	14000-U	GA	Georgia Public Service Commission Adversary Staff	Georgia Power Co.	Test year revenue forecast.
11/01	U-25687	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Nuclear decommissioning requirements transmission revenues.
11/01	U-25965	LA	Louisiana Public Service Commission	Generic .	Independent Transmission Company (“Transco”). RTO rate design.
03/02	001148-EI	FL	South Florida Hospital and Healthcare Assoc.	Florida Power & Light Company	Retail cost of service, rate design, resource planning and demand side management.
06/02	U-25965	LA	Louisiana Public Service Commission	Entergy Gulf States Entergy Louisiana	RTO Issues
07/02	U-21453	LA	Louisiana Public Service Commission	SWEPCO, AEP	Jurisdictional Business Sep. - Texas Restructuring Plan.

Expert Testimony Appearances
of
Stephen J. Baron
As of June 2021

Date	Case	Jurisdict.	Party	Utility	Subject
08/02	U-25888	LA	Louisiana Public Service Commission	Entergy Louisiana, Inc. Entergy Gulf States, Inc.	Modifications to the Inter-Company System Agreement, Production Cost Equalization.
08/02	EL01-88-000	FERC	Louisiana Public Service Commission	Entergy Services Inc. and the Entergy Operating Companies	Modifications to the Inter-Company System Agreement, Production Cost Equalization.
11/02	02S-315EG	CO	CF&I Steel & Climax Molybdenum Co.	Public Service Co. of Colorado	Fuel Adjustment Clause
01/03	U-17735	LA	Louisiana Public Service Commission	Louisiana Coops	Contract Issues
02/03	02S-594E	CO	Cripple Creek and Victor Gold Mining Co.	Aquila, Inc.	Revenue requirements, purchased power.
04/03	U-26527	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Weather normalization, power purchase expenses, System Agreement expenses.
11/03	ER03-753-000	FERC	Louisiana Public Service Commission Staff	Entergy Services, Inc. and the Entergy Operating Companies	Proposed modifications to System Agreement Tariff MSS-4.
11/03	ER03-583-000 ER03-583-001 ER03-583-002 ER03-681-000, ER03-681-001 ER03-682-000, ER03-682-001 ER03-682-002	FERC	Louisiana Public Service Commission	Entergy Services, Inc., the Entergy Operating Companies, EWO Market-Ing, L.P, and Entergy Power, Inc.	Evaluation of Wholesale Purchased Power Contracts.
12/03	U-27136	LA	Louisiana Public Service Commission	Entergy Louisiana, Inc.	Evaluation of Wholesale Purchased Power Contracts.
01/04	E-01345-03-0437	AZ	Kroger Company	Arizona Public Service Co.	Revenue allocation rate design.
02/04	00032071	PA	Duquesne Industrial Intervenors	Duquesne Light Company	Provider of last resort issues.
03/04	03A-436E	CO	CF&I Steel, LP and Climax Molybedenum	Public Service Company of Colorado	Purchased Power Adjustment Clause.

Expert Testimony Appearances
of
Stephen J. Baron
As of June 2021

Date	Case	Jurisdict.	Party	Utility	Subject
04/04	2003-00433 2003-00434	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas & Electric Co. Kentucky Utilities Co.	Cost of Service Rate Design
0-6/04	03S-539E	CO	Cripple Creek, Victor Gold Mining Co., Goodrich Corp., Holcim (U.S.,), Inc., and The Trane Co.	Aquila, Inc.	Cost of Service, Rate Design Interruptible Rates
06/04	R-00049255	PA	PP&L Industrial Customer Alliance PPLICA	PPL Electric Utilities Corp.	Cost of service, rate design, tariff issues and transmission service charge.
10/04	04S-164E	CO	CF&I Steel Company, Climax Mines	Public Service Company of Colorado	Cost of service, rate design, Interruptible Rates.
03/05	Case No. 2004-00426 Case No. 2004-00421	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Louisville Gas & Electric Co.	Environmental cost recovery.
06/05	050045-EI	FL	South Florida Hospital and Healthcare Assoc.	Florida Power & Light Company	Retail cost of service, rate design
07/05	U-28155	LA	Louisiana Public Service Commission Staff	Entergy Louisiana, Inc. Entergy Gulf States, Inc.	Independent Coordinator of Transmission – Cost/Benefit
09/05	Case Nos. 05-0402-E-CN 05-0750-E-PC	WV	West Virginia Energy Users Group	Mon Power Co. Potomac Edison Co.	Environmental cost recovery, Securitization, Financing Order
01/06	2005-00341	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Company	Cost of service, rate design, transmission expenses. Congestion Cost Recovery Mechanism
03/06	U-22092	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Separation of EGSI into Texas and Louisiana Companies.
03/06	05-1278-E-PC -PW-42T	WV	West Virginia Energy Users Group	Appalachian Power Co. Wheeling Power Co.	Retail cost of service, rate design.
04/06	U-25116	LA	Louisiana Public Service Commission Staff	Entergy Louisiana, Inc.	Transmission Prudence Investigation
06/06	R-00061346 C0001-0005	PA	Duquesne Industrial Intervenors & IECPA	Duquesne Light Co.	Cost of Service, Rate Design, Transmission Service Charge, Tariff Issues
06/06	R-00061366 R-00061367 P-00062213 P-00062214		Met-Ed Industrial Energy Users Group and Penelec Industrial Customer Alliance	Metropolitan Edison Co. Pennsylvania Electric Co.	Generation Rate Cap, Transmission Service Charge, Cost of Service, Rate Design, Tariff Issues
07/06	U-22092 Sub-J	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Separation of EGSI into Texas and Louisiana Companies.

Expert Testimony Appearances
of
Stephen J. Baron
As of June 2021

Date	Case	Jurisdict.	Party	Utility	Subject
07/06	Case No. 2006-00130 Case No. 2006-00129	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Louisville Gas & Electric Co.	Environmental cost recovery.
08/06	Case No. PUE-2006-00065	VA	Old Dominion Committee For Fair Utility Rates	Appalachian Power Co.	Cost Allocation, Allocation of Rev Incr, Off-System Sales margin rate treatment
09/06	E-01345A-05-0816	AZ	Kroger Company	Arizona Public Service Co.	Revenue allocation, cost of service, rate design.
11/06	Doc. No. 97-01-15RE02	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power United Illuminating	Rate unbundling issues.
01/07	Case No. 06-0960-E-42T	WV	West Virginia Energy Users Group	Mon Power Co. Potomac Edison Co.	Retail Cost of Service Revenue apportionment
03/07	U-29764	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc. Entergy Louisiana, LLC	Implementation of FERC Decision Jurisdictional & Rate Class Allocation
05/07	Case No. 07-63-EL-UNC	OH	Ohio Energy Group	Ohio Power, Columbus Southern Power	Environmental Surcharge Rate Design
05/07	R-00049255 Remand	PA	PP&L Industrial Customer Alliance PPLICA	PPL Electric Utilities Corp.	Cost of service, rate design, tariff issues and transmission service charge.
06/07	R-00072155	PA	PP&L Industrial Customer Alliance PPLICA	PPL Electric Utilities Corp.	Cost of service, rate design, tariff issues.
07/07	Doc. No. 07F-037E	CO	Gateway Canyons LLC	Grand Valley Power Coop.	Distribution Line Cost Allocation
09/07	Doc. No. 05-UR-103	WI	Wisconsin Industrial Energy Group, Inc.	Wisconsin Electric Power Co.	Cost of Service, rate design, tariff Issues, Interruptible rates.
11/07	ER07-682-000	FERC	Louisiana Public Service Commission Staff	Entergy Services, Inc. and the Entergy Operating Companies	Proposed modifications to System Agreement Schedule MSS-3. Cost functionalization issues.
1/08	Doc. No. 20000-277-ER-07	WY	Cimarex Energy Company	Rocky Mountain Power (PacifiCorp)	Vintage Pricing, Marginal Cost Pricing Projected Test Year
1/08	Case No. 07-551	OH	Ohio Energy Group	Ohio Edison, Toledo Edison Cleveland Electric Illuminating	Class Cost of Service, Rate Restructuring, Apportionment of Revenue Increase to Rate Schedules
2/08	ER07-956	FERC	Louisiana Public Service Commission Staff	Entergy Services, Inc. and the Entergy Operating Companies	Entergy's Compliance Filing System Agreement Bandwidth Calculations.
2/08	Doc No. P-00072342	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Default Service Plan issues.
3/08	Doc No. E-01933A-05-0650	AZ	Kroger Company	Tucson Electric Power Co.	Cost of Service, Rate Design

Expert Testimony Appearances
of
Stephen J. Baron
As of June 2021

Date	Case	Jurisdict.	Party	Utility	Subject
05/08	08-0278 E-GI	WV	West Virginia Energy Users Group	Appalachian Power Co. American Electric Power Co.	Expanded Net Energy Cost "ENEC" Analysis.
6/08	Case No. 08-124-EL-ATA	OH	Ohio Energy Group	Ohio Edison, Toledo Edison Cleveland Electric Illuminating	Recovery of Deferred Fuel Cost
7/08	Docket No. 07-035-93	UT	Kroger Company	Rocky Mountain Power Co.	Cost of Service, Rate Design
08/08	Doc. No. 6680-UR-116	WI	Wisconsin Industrial Energy Group, Inc.	Wisconsin Power and Light Co.	Cost of Service, rate design, tariff Issues, Interruptible rates.
09/08	Doc. No. 6690-UR-119	WI	Wisconsin Industrial Energy Group, Inc.	Wisconsin Public Service Co.	Cost of Service, rate design, tariff Issues, Interruptible rates.
09/08	Case No. 08-936-EL-SSO	OH	Ohio Energy Group	Ohio Edison, Toledo Edison Cleveland Electric Illuminating	Provider of Last Resort Competitive Solicitation
09/08	Case No. 08-935-EL-SSO	OH	Ohio Energy Group	Ohio Edison, Toledo Edison Cleveland Electric Illuminating	Provider of Last Resort Rate Plan
09/08	Case No. 08-917-EL-SSO 08-918-EL-SSO	OH	Ohio Energy Group	Ohio Power Company Columbus Southern Power Co.	Provider of Last Resort Rate Plan
10/08	2008-00251 2008-00252	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas & Electric Co. Kentucky Utilities Co.	Cost of Service, Rate Design
11/08	08-1511 E-GI	WV	West Virginia Energy Users Group	Mon Power Co. Potomac Edison Co.	Expanded Net Energy Cost "ENEC" Analysis.
11/08	M-2008-2036188, M-2008-2036197	PA	Met-Ed Industrial Energy Users Group and Penelec Industrial Customer Alliance	Metropolitan Edison Co. Pennsylvania Electric Co.	Transmission Service Charge
01/09	ER08-1056	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	Entergy's Compliance Filing System Agreement Bandwidth Calculations.
01/09	E-01345A-08-0172	AZ	Kroger Company	Arizona Public Service Co.	Cost of Service, Rate Design
02/09	2008-00409	KY	Kentucky Industrial Utility Customers, Inc.	East Kentucky Power Cooperative, Inc.	Cost of Service, Rate Design
5/09	PUE-2009 -00018	VA	VA Committee For Fair Utility Rates	Dominion Virginia Power Company	Transmission Cost Recovery Rider
5/09	09-0177-E-GI	WV	West Virginia Energy Users Group	Appalachian Power Company	Expanded Net Energy Cost "ENEC" Analysis
6/09	PUE-2009 -00016	VA	VA Committee For Fair Utility Rates	Dominion Virginia Power Company	Fuel Cost Recovery Rider

Expert Testimony Appearances
of
Stephen J. Baron
As of June 2021

Date	Case	Jurisdict.	Party	Utility	Subject
6/09	PUE-2009 -00038	VA	Old Dominion Committee For Fair Utility Rates	Appalachian Power Company	Fuel Cost Recovery Rider
7/09	080677-EI	FL	South Florida Hospital and Healthcare Assoc.	Florida Power & Light Company	Retail cost of service, rate design
8/09	U-20925 (RRF 2004)	LA	Louisiana Public Service Commission Staff	Entergy Louisiana LLC	Interruptible Rate Refund Settlement
9/09	09AL-299E	CO	CF&I Steel Company Climax Molybdenum	Public Service Company of Colorado	Energy Cost Rate issues
9/09	Doc. No. 05-UR-104	WI	Wisconsin Industrial Energy Group, Inc.	Wisconsin Electric Power Co.	Cost of Service, rate design, tariff Issues, Interruptible rates.
9/09	Doc. No. 6680-UR-117	WI	Wisconsin Industrial Energy Group, Inc.	Wisconsin Power and Light Co.	Cost of Service, rate design, tariff Issues, Interruptible rates.
10/09	Docket No. 09-035-23	UT	Kroger Company	Rocky Mountain Power Co.	Cost of Service, Allocation of Rev Increase
10/09	09AL-299E	CO	CF&I Steel Company Climax Molybdenum	Public Service Company of Colorado	Cost of Service, Rate Design
11/09	PUE-2009 -00019	VA	VA Committee For Fair Utility Rates	Dominion Virginia Power Company	Cost of Service, Rate Design
11/09	09-1485 E-P	WV	West Virginia Energy Users Group	Mon Power Co. Potomac Edison Co.	Expanded Net Energy Cost “ENEC” Analysis.
12/09	Case No. 09-906-EL-SSO	OH	Ohio Energy Group	Ohio Edison, Toledo Edison Cleveland Electric Illuminating	Provider of Last Resort Rate Plan
12/09	ER09-1224	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	Entergy’s Compliance Filing System Agreement Bandwidth Calculations.
12/09	Case No. PUE-2009-00030	VA	Old Dominion Committee For Fair Utility Rates	Appalachian Power Co.	Cost Allocation, Allocation of Rev Increase, Rate Design
2/10	Docket No. 09-035-23	UT	Kroger Company	Rocky Mountain Power Co.	Rate Design
3/10	Case No. 09-1352-E-42T	WV	West Virginia Energy Users Group	Mon Power Co. Potomac Edison Co.	Retail Cost of Service Revenue apportionment
3/10	E015/ GR-09-1151	MN	Large Power Intervenors	Minnesota Power Co.	Cost of Service, rate design
4/10	EL09-61	FERC	Louisiana Public Service Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	System Agreement Issues Related to off-system sales
4/10	2009-00459	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Company	Cost of service, rate design, transmission expenses.

Expert Testimony Appearances
of
Stephen J. Baron
As of June 2021

Date	Case	Jurisdict.	Party	Utility	Subject
4/10	2009-00548 2009-00549	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas & Electric Co. Kentucky Utilities Co.	Cost of Service, Rate Design
7/10	R-2010-2161575	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy Company	Cost of Service, Rate Design
09/10	2010-00167	KY	Kentucky Industrial Utility Customers, Inc.	East Kentucky Power Cooperative, Inc.	Cost of Service, Rate Design
09/10	10M-245E	CO	CF&I Steel Company Climax Molybdenum	Public Service Company of Colorado	Economic Impact of Clean Air Act
11/10	10-0699-E-42T	WV	West Virginia Energy Users Group	Appalachian Power Company	Cost of Service, Rate Design, Transmission Rider
11/10	Doc. No. 4220-UR-116	WI	Wisconsin Industrial Energy Group, Inc.	Northern States Power Co. Wisconsin	Cost of Service, rate design
12/10	10A-554EG	CO	CF&I Steel Company Climax Molybdenum	Public Service Company	Demand Side Management Issues
12/10	10-2586-EL-SSO	OH	Ohio Energy Group	Duke Energy Ohio	Provider of Last Resort Rate Plan Electric Security Plan
3/11	20000-384-ER-10	WY	Wyoming Industrial Energy Consumers	Rocky Mountain Power Wyoming	Electric Cost of Service, Revenue Apportionment, Rate Design
5/11	2011-00036	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers Electric Corporation	Cost of Service, Rate Design
6/11	Docket No. 10-035-124	UT	Kroger Company	Rocky Mountain Power Co.	Class Cost of Service
6/11	PUE-2011-00045	VA	VA Committee For Fair Utility Rates	Dominion Virginia Power Company	Fuel Cost Recovery Rider
07/11	U-29764	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc. Entergy Louisiana, LLC	Entergy System Agreement - Successor Agreement, Revisions, RTO Day 2 Market Issues
07/11	Case Nos. 11-346-EL-SSO 11-348-EL-SSO	OH	Ohio Energy Group	Ohio Power Company Columbus Southern Power Co.	Electric Security Rate Plan, Provider of Last Resort Issues
08/11	PUE-2011-00034	VA	Old Dominion Committee For Fair Utility Rates	Appalachian Power Co.	Cost Allocation, Rate Recovery of RPS Costs
09/11	2011-00161 2011-00162	KY	Kentucky Industrial Utility	Louisville Gas & Electric Co. Kentucky Utilities Company	Environmental Cost Recovery
09/11	Case Nos. 11-346-EL-SSO 11-348-EL-SSO	OH	Ohio Energy Group	Ohio Power Company Columbus Southern Power Co.	Electric Security Rate Plan, Stipulation Support Testimony
10/11	11-0452 E-P-T	WV	West Virginia Energy Users Group	Mon Power Co. Potomac Edison Co.	Energy Efficiency/Demand Reduction Cost Recovery

Expert Testimony Appearances
of
Stephen J. Baron
As of June 2021

Date	Case	Jurisdict.	Party	Utility	Subject
11/11	11-1272 E-P	WV	West Virginia Energy Users Group	Mon Power Co. Potomac Edison Co.	Expanded Net Energy Cost "ENEC" Analysis
11/11	E-01345A-11-0224	AZ	Kroger Company	Arizona Public Service Co.	Decoupling
12/11	E-01345A-11-0224	AZ	Kroger Company	Arizona Public Service Co.	Cost of Service, Rate Design
3/12	Case No. 2011-00401	KY	Kentucky Industrial Utility Consumers	Kentucky Power Company	Environmental Cost Recovery
4/12	2011-00036 Rehearing Case	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers Electric Corporation	Cost of Service, Rate Design
5/12	2011-346 2011-348	OH	Ohio Energy Group	Ohio Power Company	Electric Security Rate Plan Interruptible Rate Issues
6/12	PUE-2012 -00051	VA	Old Dominion Committee For Fair Utility Rates	Appalachian Power Company	Fuel Cost Recovery Rider
6/12	12-00012 12-00026	TN	Eastman Chemical Co. Air Products and Chemicals, Inc.	Kingsport Power Company	Demand Response Programs
6/12	Docket No. 11-035-200	UT	Kroger Company	Rocky Mountain Power Co.	Class Cost of Service
6/12	12-0275-E-GI	WV	West Virginia Energy Users Group	Appalachian Power Company	Energy Efficiency Rider
6/12	12-0399-E-P	WV	West Virginia Energy Users Group	Appalachian Power Company	Expanded Net Energy Cost ("ENEC")
7/12	120015-EI	FL	South Florida Hospital and Healthcare Assoc.	Florida Power & Light Company	Retail cost of service, rate design
7/12	2011-00063	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers Electric Corporation	Environmental Cost Recovery
8/12	Case No. 2012-00226	KY	Kentucky Industrial Utility Consumers	Kentucky Power Company	Real Time Pricing Tariff
9/12	ER12-1384	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Entergy System Agreement, Cancelled Plant Cost Treatment
9/12	2012-00221 2012-00222	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas & Electric Co. Kentucky Utilities Co.	Cost of Service, Rate Design
11/12	12-1238 E-GI	WV	West Virginia Energy Users Group	Mon Power Co. Potomac Edison Co.	Expanded Net Energy Cost Recovery Issues
12/12	U-29764	LA	Louisiana Public Service Commission Staff	Entergy Gulf States Louisiana	Purchased Power Contracts
12/12	EL09-61	FERC	Louisiana Public Service Service Commission	Entergy Services, Inc. and the Entergy Operating	System Agreement Issues Related to off-system sales

Expert Testimony Appearances
of
Stephen J. Baron
As of June 2021

Date	Case	Jurisdict.	Party	Utility	Subject
				Companies	Damages Phase
12/12	E-01933A- 12-0291	AZ	Kroger Company	Tucson Electric Power Co.	Decoupling
1/13	12-1188 E-PC	WV	West Virginia Energy Users Group	Appalachian Power Company	Securitization of ENEC Costs
1/13	E-01933A- 12-0291	AZ	Kroger Company	Tucson Electric Power Co.	Cost of Service, Rate Design
4/13	12-1571 E-PC	WV	West Virginia Energy Users Group	Mon Power Co. Potomac Edison Co.	Generation Resource Transition Plan Issues
4/13	PUE-2012 -00141	VA	Old Dominion Committee For Fair Utility Rates	Appalachian Power Company	Generation Asset Transfer Issues
6/13	12-1655 E-PC/11-1775 -E-P	WV	West Virginia Energy Users Group	Appalachian Power Company	Generation Asset Transfer Issues
06/13	U-32675	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc. Entergy Louisiana, LLC	MISO Joint Implementation Plan Issues
7/13	130040-EI	FL	WCF Health Utility Alliance	Tampa Electric Company	Cost of Service, Rate Design
7/13	13-0467- E-P	WV	West Virginia Energy Users Group	Appalachian Power Company	Expanded Net Energy Cost (“ENEC”)
7/13	13-0462- E-GI	WV	West Virginia Energy Users Group	Appalachian Power Company	Energy Efficiency Issues
8/13	13-0557- E-P	WV	West Virginia Energy Users Group	Appalachian Power Company	Right-of-Way, Vegetation Control Cost Recovery Surcharge Issues
10/13	2013-00199	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers Electric Corporation	Ratemaking Policy Associated with Rural Economic Reserve Funds
10/13	13-0764- E-CN	WV	West Virginia Energy Users Group	Appalachian Power Company	Rate Recovery Issues – Clinch River Gas Conversion Project
11/13	R-2013- 2372129	PA	United States Steel Corporation	Duquesne Light Company	Cost of Service, Rate Design
11/13	13A-0686EG	CO	CF&I Steel Company Climax Molybdenum	Public Service Company of Colorado	Demand Side Management Issues
11/13	13-1064- E-P	WV	West Virginia Energy Users Group	Mon Power Co. Potomac Edison Co.	Right-of-Way, Vegetation Control Cost Recovery Surcharge Issues
4/14	ER-432-002	FERC	Louisiana Public Service Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	System Agreement Issues Related to Union Pacific Railroad Litigation Settlement
5/14	2013-2385 2013-2386	OH	Ohio Energy Group	Ohio Power Company	Electric Security Rate Plan Interruptible Rate Issues

Expert Testimony Appearances
of
Stephen J. Baron
As of June 2021

Date	Case	Jurisdict.	Party	Utility	Subject
5/14	14-0344- E-GI	WV	West Virginia Energy Users Group	Appalachian Power Company	Expanded Net Energy Cost ("ENEC")
5/14	14-0345- E-PC	WV	West Virginia Energy Users Group	Appalachian Power Company	Energy Efficiency Issues
5/14	Docket No. 13-035-184	UT	Kroger Company	Rocky Mountain Power Co.	Class Cost of Service
7/14	PUE-2014 -00007	VA	Old Dominion Committee For Fair Utility Rates	Appalachian Power Company	Renewable Portfolio Standard Rider Issues
7/14	ER13-2483	FERC	Bear Island Paper WB LLC	Old Dominion Electric Cooperative	Cost of Service, Rate Design Issues
8/14	14-0546- E-PC	WV	West Virginia Energy Users Group	Appalachian Power Company	Rate Recovery Issues – Mitchell Asset Transfer
8/14	PUE-2014 -00026	VA	Old Dominion Committee	Appalachian Power Company	Biennial Review Case - Cost of Service Issues
9/14	14-841-EL- SSO	OH	Ohio Energy Group	Duke Energy Ohio	Electric Security Rate Plan Standard Service Offer
10/14	14-0702- E-42T	WV	West Virginia Energy Users Group	Mon Power Co. Potomac Edison Co.	Cost of Service, Rate Design
11/14	14-1550- E-P	WV	West Virginia Energy Users Group	Mon Power Co. Potomac Edison Co.	Expanded Net Energy Cost ("ENEC")
12/14	EL14-026	SD	Black Hills Power Industrial Intervenors	Black Hills Power, Inc.	Cost of Service Issues
12/14	14-1152- E-42T	WV	West Virginia Energy Users Group	Appalachian Power Company	Cost of Service, Rate Design transmission, lost revenues
2/15	14-1297 EI-SS0	OH	Ohio Energy Group	Ohio Edison, Toledo Edison Cleveland Electric Illuminating	Electric Security Rate Plan Standard Service Offer
3/15	2014-00396	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Company	Cost of service, rate design, transmission expenses.
3/15	2014-00371 2014-00372	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas & Electric Co. Kentucky Utilities Co.	Cost of Service, Rate Design
5/15	EL10-65	FERC	Louisiana Public Service Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	System Agreement Issues Related to Interruptible load
5/15	15-0301- E-GI	WV	West Virginia Energy Users Group	Appalachian Power Company	Expanded Net Energy Cost ("ENEC")
5/15	15-0303- E-P	WV	West Virginia Energy Users Group	Appalachian Power Company, Wheeling Power Co.	Energy Efficiency/Demand Response

Expert Testimony Appearances
of
Stephen J. Baron
As of June 2021

Date	Case	Jurisdict.	Party	Utility	Subject
6/15	14-1580-EL-RDR	OH	Ohio Energy Group	Duke Energy Ohio	Energy Efficiency Rider Issues
7/15	EL10-65	FERC	Louisiana Public Service Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	System Agreement Issues Related to Off-System Sales and Bandwidth Tariff
8/15	PUE-2015 -00034	VA	Old Dominion Committee For Fair Utility Rates	Appalachian Power Company	Renewable Portfolio Standard Rider Issues
8/15	87-0669-E-P	WV	West Virginia Energy Users Group	Mon Power Co. Potomac Edison Co.	Cost of Service, Rate Design
11/15	D2015-6.51	MT	Montana Large Customer Group	Montana Dakota Utilities Co.	Class Cost of Service, Rate Design
11/15	15-1351-E-P	WV	West Virginia Energy Users Group	Mon Power Co. Potomac Edison Co.	Expanded Net Energy Cost ("ENEC")
3/16	EL01-88 Remand	FERC	Louisiana Public Service Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	System Agreement Issues Related to Bandwidth Tariff
5/16	16-0239-E-ENEC	WV	West Virginia Energy Users Group	Appalachian Power Company	Expanded Net Energy Cost ("ENEC")
6/16	E-01933A-15-0322	AZ	Kroger Company	Tucson Electric Power Co.	Cost of Service, Rate Design
6/16	16-00001	TN	East Tennessee Energy Consumers	Kingsport Power Co.	Cost of Service, Rate Design
6/16	14-1297-EL-SS0-Rehearing	OH	Ohio Energy Group	Ohio Edison, Toledo Edison Cleveland Electric Illuminating	Electric Security Rate Plan Standard Service Offer
06/16	15-1734-E-T-PC	WV	West Virginia Energy Users Group	Appalachian Power Company, Wheeling Power Co.	Demand Response Rider
7/16	160021-EI	FL	South Florida Hospital and Healthcare Assoc.	Florida Power & Light Company	Retail cost of service, rate design
7/16	16AL-0048E	CO	CF&I.Steel LP Climax Molybdenum	Public Service Company of Colorado	Cost of Service, Rate Design
7/16	16-0403-E-P	WV	West Virginia Energy Users Group	Mon Power Co. Potomac Edison Co.	Energy Efficiency/Demand Response
10/16	16-1121-E-ENEC	WV	West Virginia Energy Users Group	Mon Power Co. Potomac Edison Co.	Expanded Net Energy Cost ("ENEC")
11/16	16-0395-EL-SSO	OH	Ohio Energy Group	Dayton Power & Light	Electric Security Rate Plan
11/16	EL09-61-004 Remand	FERC	Louisiana Public Service Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	System Agreement Issues Related to off-system sales Damages Phase

Expert Testimony Appearances
of
Stephen J. Baron
As of June 2021

Date	Case	Jurisdict.	Party	Utility	Subject
12/16	1139	D.C.	Healthcare Council of the National Capital Area	Potomac Electric Power Co.	Cost of Service, Rate Design
1/17	E-01345A-16-0036	AZ	Kroger	Arizona Public Service Co.	Cost of Service, Rate Design
2/17	16-1026-E-PC	WV	West Virginia Energy Users Group	Appalachian Power Co.	Wind Project Purchase Power Agreement
3/17	2016-00370 2016-00371	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas & Electric Co. Kentucky Utilities Co.	Cost of Service, Rate Design
5/17	16-1852	OH	Ohio Energy Group	Ohio Power Company	Electric Security Rate Plan Interruptible Rate Issues
7/17	17-00032	TN	East Tennessee Energy Consumers	Kingsport Power Co.	Vegetation Management Cost Recovery
8/17	17-0631-E-P	WV	West Virginia Energy Users Group	Monongahela Power Co.	Electric Energy Purchase Agreement
8/17	17-0296-E-PC	WV	West Virginia Energy Users Group	Monongahela Power Co.	Generation Resource Asset Transfer
9/17	2017-0179	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Company	Cost of service, rate design, transmission cost recover.
9/17	17-0401 E-P	WV	West Virginia Energy Users Group	Appalachian Power Company	Energy Efficiency Issues
12/17	17-0894-E-PC	WV	West Virginia Energy Users Group	Appalachian Power Co.	Wind Project Asset Purchase
5/18	1150/ 1151	D.C.	Healthcare Council of the National Capital Area	Potomac Electric Power Co.	Cost of Service, Rate Design Tax Cut and Jobs Act Issues
6/18	17-00143	TN	East Tennessee Energy Consumers	Kingsport Power Co.	Storm Damage Rider Cost Recovery
7/18	18-0503-E-ENEC	WV	West Virginia Energy Users Group	Appalachian Power Company	Expanded Net Energy Cost (“ENEC”)
7/18	18-0504-E-P	WV	West Virginia Energy Users Group	Appalachian Power Company	Vegetation Management Cost Recovery
7/18	G.O.236.1	WV	West Virginia Energy Users Group	Appalachian Power Company	Tax Cut and Jobs Act Issues
7/18	G.O.236.1	WV	West Virginia Energy Users Group	Mon Power Co. Potomac Edison Co.	Tax Cut and Jobs Act Issues
10/18	18-0646-E-42T	WV	West Virginia Energy Users Group	Appalachian Power Company	Cost of Service, Rate Design TCJA issues
10/18	18-00038	TN	East Tennessee Energy Consumers	Kingsport Power Co.	Tax Cut and Jobs Act Issues

Expert Testimony Appearances
of
Stephen J. Baron
As of June 2021

Date	Case	Jurisdict.	Party	Utility	Subject
11/18	18-1231- E-ENEC	WV	West Virginia Energy Users Group	Mon Power Co. Potomac Edison Co.	Expanded Net Energy Cost ("ENEC")
11/18	2018-00054	VA	Old Dominion Committee For Fair Utility Rates	Appalachian Power Company	Tax Cut and Jobs Act Issues
12/18	2018-00134	VA	Collegiate Clean Energy	Appalachian Power Company	Competitive Service Provider Issues
1/19	2018-00294 2018-00295	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas & Electric Co. Kentucky Utilities Co.	Cost of Service, Rate Design
1/19	2018-00101	VA	VA Committee For Fair Utility Rates	Dominion Virginia Power Company	Cost of Service
2/19	UD-18-07	City of New Orleans	Crescent City Power Users Group	Entergy New Orleans	Cost of Service, Rate Design
4/19	42310	GA	Georgia Public Service Commission Staff	Georgia Power Company	2019 Integrated Resource Plan Optimal Reserve Margin Issues
7/19	19-0396 E-P	WV	West Virginia Energy Users Group	Appalachian Power Company	Energy Efficiency Issues
10/19	19-0387 E-PC	WV	West Virginia Energy Users Group	Appalachian Power Company	Economic Development Fund
10/19	19-0564 E-T	WV	West Virginia Energy Users Group	Appalachian Power Company	Mitchell Generating Plant Surcharge
10/19	E-01933A- 19-0028	AZ	Kroger Company	Tucson Electric Power Co.	Cost of Service, Rate Design
11/19	19-0785 E-ENEC	WV	West Virginia Energy Users Group	Mon Power Co. Potomac Edison Co.	Expanded Net Energy Cost ("ENEC")
11/19	2018-00101	VA	VA Committee For Fair Utility Rates	Dominion Virginia Power Company	Cost of Service
11/22	2019-00170 -UT	NM	COG Operating, LLC	Southwestern Public Service Co.	Cost of Service, Rate Design
12/19	19-1028 E-PC	WV	West Virginia Energy Users Group	Mon Power Co. Potomac Edison Co.	PURPA Contract Buy-out
4/20	20-00064	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers Electric Cooperative, Inc.	Rate Design
7/20	2019-226-E	SC	The South Carolina Office of Regulatory Staff	Dominion Energy South Carolina	2020 Integrated Resource Plan Load Forecasting, Reserve Margin Issue
7/20	2020-00015	VA	Old Dominion Committee For Fair Utility Rates	Appalachian Power Company	2020 Triennial Review Case - Cost Allocation, Revenue Apportionment
8/20	E-01345A- 19-0236	AZ	Kroger Company	Arizona Public Service Co	Cost of Service, Rate Design

Expert Testimony Appearances
of
Stephen J. Baron
As of June 2021

Date	Case	Jurisdict.	Party	Utility	Subject
10/20	2020-00174	KY	Kentucky Industrial Utility Customers, Inc., KY AG	Kentucky Power Company	Cost of service, net metering, transmission costs.
11/20	20-0665 E-ENEC	WV	West Virginia Energy Users Group	Mon Power Co. Potomac Edison Co	Expanded Net Energy Cost ("ENEC")
2/21	2019-224-E 2019-225-E	SC	The South Carolina Office of Regulatory Staff	Duke Energy Carolinas Duke Energy Progress	2020 Integrated Resource Plan Load Forecasting, Reserve Margin Issue
3/21	2020-00349 2020-00350	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas & Electric Co. Kentucky Utilities Co.	Cost of Service, Rate Design. Net Metering issues
3/21	20AL-0432E	CO	Climax Molybdenum	Public Service Company of Colorado	Cost of Service, Rate Design
3/21	20-1476-	OH	Ohio Energy Group	Ohio Edison, Toledo Edison Cleveland Electric Illuminating	Electric Security Rate Plan Standard Service Offer
5/21	20-1040 E-CN	WV	West Virginia Energy Users Group	Appalachian Power Company	Environmental CCN and Surcharge
5/21	20-1012 E-P	WV	West Virginia Energy Users Group	Appalachian Power Company	Infrastructure Investment Tracker and Surcharge
5/21	2020-00238 -UT	NM	COG Operating, LLC	Southwestern Public Service Co.	Cost of Service, Rate Design
6/21	2021-00045	VA	VA Committee For Fair Utility Rates	Dominion Virginia Power Company	Coal Combustion Residuals Rider CCR Cost Allocation, Rate Design

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF:

THE ELECTRONIC APPLICATION OF	**)**	
EAST KENTUCKY POWER COOPERATIVE, INC.	**)**	
FOR A GENERAL ADJUSTMENT OF RATES,	**)**	**Case No. 2021-00103**
APPROVAL OF DEPRECIATION STUDY,	**)**	
AMORTIZATION OF CERTAIN REGULATORY	**)**	
ASSETS, AND OTHER RELIEF	**)**	

EXHIBIT__(SJB-2)

OF

STEPHEN J. BARON

EAST KENTUCKY POWER COOPERATIVE, INC.
PSC CASE NO. 2021-00103
SUPPLEMENTAL SET OF DATA REQUESTS RESPONSE

NUCOR STEEL GALLATIN'S SET OF DATA REQUESTS DATED 6/4/21
REQUEST 6
RESPONSIBLE PERSON: **Richard J. Macke**
COMPANY: **East Kentucky Power Cooperative, Inc.**

Request 6. With regard to the response to Nucor Initial Request 1, please reconcile the maximum hourly kW demand shown for the Contract class in 2019 with the value shown for the maximum NCP demand for the Contract class in EKPC's class cost of service study (Maximum NCP Demand by Class).

Response 6. The maximum hourly kW demand shown in the data provided in response to Nucor Initial Request 1 does not reconcile with the maximum NCP demand for the Contract class in the class cost of service study. Using the data that was available when the class cost of service study was completed, the maximum NCP demand for the Contract class used in the class cost of service study was set to be equal to the peak billing demand. Upon review of more recent data provided by EKPC in response to Nucor Initial Request 1, it is believed that the maximum NCP demand for the Contract class to be used in the class cost of service should come from that file, which would change it from approximately 175 MW to 164 MW. The impact of this change is summarized in the response provided to Nucor Second Request 10.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF:

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AMORTIZATION OF CERTAIN REGULATORY	**)**	
ASSETS, AND OTHER RELIEF	**)**	

EXHIBIT__(SJB-3)

OF

STEPHEN J. BARON

EKPC RESPONSE TO NUCOR 2-10 - CORRECTION OF NUCOR NCP DEMAND, RATE C NCP DEMAND
East Kentucky Power Cooperative, Inc.
Allocation of Revenue Requirements to Rate Classes Excluding Environmental Surcharge Costs
TY 2019 - Pro Forma - Excludes ES and FAC

(a) Line No.	(b) Description	(c) Alloc. Factor	(d) Total ($)	(e) Rate B ($)	(f) Rate C ($)	(g) Rate E ($)	(h) Rate G ($)	(i) Contract ($)	(j) Steam ($)	(k) Rate TGP ($)
1	**Revenue**									
2	Total Revenue		422,130,617	27,170,310	7,931,946	342,414,808	10,833,171	23,685,067	4,516,945	5,578,370
3										
4	**Allocation of Revenue Requirements**									
5	Production Capacity			-						
6	Interruptible Credit [1]	Direct								
7	Remaining Prod. Capacity Rev. Req.	AED	172,575,237	8,849,977	2,571,816	147,983,798	3,824,479	9,345,166		
8	Subtotal Production Capacity		172,575,237	8,849,977	2,571,816	147,983,798	3,824,479	9,345,166	-	-
9	Production Energy									
10	Energy Cost Assigned to Rate TGP	Direct	4,743,510							4,743,510
11	On-Peak F&PP [2]	ON-ENG	24,129,992	1,964,131	518,568	19,611,815	878,322	1,157,155		
12	Off-Peak F&PP [2]	OFF-ENG	19,029,264	1,734,737	468,832	14,015,505	775,742	2,034,449		
13	Remaining Energy Revenue Req.	TOT-ENG	118,955,791	10,276,200	2,747,700	92,048,576	4,595,323	9,287,992		
14	Subtotal Production Energy		166,858,556	13,975,067	3,735,100	125,675,896	6,249,388	12,479,595	-	4,743,510
15	Steam Service	Direct	4,820,197						4,820,197	
16	Transmission									
17	Transm. Cost Assigned to Rate TGP [3]	Direct	834,860							834,860
18	Remaining Transm. Rev. Req.	12CP	104,172,870	5,953,203	1,608,084	87,016,749	2,496,450	7,098,384		
19	Subtotal Transmission		105,007,730	5,953,203	1,608,084	87,016,749	2,496,450	7,098,384	-	834,860
20	Distribution Substations	SUB	19,197,972	-	-	19,101,350	96,622	-	-	
21	Meters	METER	2,444,085	424,279	53,782	1,936,146	17,927	5,976	5,976	
22	Subtotal		470,903,778	29,202,526	7,968,782	381,713,939	12,684,866	28,929,121	4,826,173	5,578,370
23	Plus: FCA Factor Cost		-	-	-	-	-	-	-	-
24	Plus: FCA Base Cost		-	-	-	-	-	-	-	-
25	Subtotal		470,903,778	29,202,526	7,968,782	381,713,939	12,684,866	28,929,121	4,826,173	5,578,370
26	Plus: Environmental Surcharge		-	-	-	-	-	-	-	-
27	Total Revenue Requirements		470,903,778	29,202,526	7,968,782	381,713,939	12,684,866	28,929,121	4,826,173	5,578,370
28										
29	**Revenue Requirements less Revenue**		48,773,161	2,032,216	36,837	39,299,131	1,851,694	5,244,054	309,227	-
30	Increase (Decrease) as % of Present Revenue		11.6%	7.5%	0.5%	11.5%	17.1%	22.1%	6.8%	0.0%
31										
32										
33	**Average Cost per Unit / Rate Design Data**									
34	Production Capacity	/CP Billing kW		$4.84	$4.41	$6.18	$4.80	$4.79	$0.00	$0.00
35	Production Energy - Total Average Billing M	/MWh								
36	All Hours	/MWh		$12.81	$12.68	$12.92	$12.86	$12.59	$0.00	$25.92
37	On-Peak Hours	/MWh		$13.33	$13.19	$13.38	$13.38	$13.26	$0.00	$0.00
38	Off-Peak Hours	/MWh		$12.37	$12.24	$12.42	$12.42	$12.31	$0.00	$0.00
39	Transmission	/CP Billing kW		$3.26	$2.76	$3.63	$3.13	$3.64	$0.00	$1.75
40	Substations (Average All Capacities)	/sub/mon.				$4,928.11	$8,051.83		$0.00	
41	Metering	/meter/mon.		$497.98	$497.98	$497.98	$497.98	$497.98	$497.98	N/A
42	Total Demand Charges	/CP Billing kW		$8.10	$7.17	$9.812	$7.93	$8.42	$0.00	$1.75

1 Interruptible Credits are removed from the cost data for evaluation pursuant supplemental analysis.

2 In 2019, 55.91% of fuel and purchased energy cost occurred during the on-peak period, with the remaining 44.09% occuring during the off-peak period.

3 Assign the demand (transmission) charge per contract directly to Rate TGP.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF:

THE ELECTRONIC APPLICATION OF	**)**	
EAST KENTUCKY POWER COOPERATIVE, INC.	**)**	
FOR A GENERAL ADJUSTMENT OF RATES,	**)**	**Case No. 2021-00103**
APPROVAL OF DEPRECIATION STUDY,	**)**	
AMORTIZATION OF CERTAIN REGULATORY	**)**	
ASSETS, AND OTHER RELIEF	**)**	

EXHIBIT__(SJB-4)

OF

STEPHEN J. BARON

EAST KENTUCKY POWER COOPERATIVE, INC.

(EKPC)

OPEN ACCESS TRANSMISSION TARIFF

34 Rates and Charges

The Network Customer shall pay the Transmission Provider for any Direct Assignment Facilities, Ancillary Services, and applicable study costs, consistent with Commission policy, along with the following:

34.1 Monthly Demand Charge: The Network Customer shall pay a monthly Demand Charge, as set forth in Schedule 9.

34.2 Determination of Network Customer's Monthly Network Load: The Network Customer's monthly Network Load is its hourly load (including its designated Network Load not physically interconnected with the Transmission Provider under Section 31.3) coincident with the Transmission Provider's Monthly Transmission System Peak.

34.3 Determination of Transmission Provider's Monthly Transmission System Load: The Transmission Provider's monthly Transmission System load is the Transmission Provider's Monthly Transmission System Peak minus the coincident peak usage of all Firm Point-To-Point Transmission Service customers pursuant to Part II of this Tariff plus the Reserved Capacity of all Firm Point-To-Point Transmission Service customers.

34.4 Redispatch Charge: The Network Customer shall pay a Load Ratio Share of any redispatch costs allocated between the Network Customer and the Transmission Provider pursuant to Section 33. To the extent that the Transmission Provider incurs an obligation to the Network Customer for redispatch costs in accordance with Section 33, such amounts shall be credited against the Network Customer's bill for the applicable month.

34.5 Stranded Cost Recovery: The Transmission Provider reserves the right to recover stranded costs from the Network Customer pursuant to this Tariff.

(b) At least thirty-six (36) hours in advance of every calendar day, the Transmission Customer shall provide its best forecast of any planned transmission or Network Resource outage(s) and other operating information that would assist the Transmission Provider in the reliable operation of the Control Area. In the event that such planned outages cannot be accommodated due to a transmission constraint on the Transmission Provider's Transmission System, the provisions of Section 34 of the Tariff will be implemented.

(c) The Transmission Provider and the Transmission Customer shall notify and coordinate with the other party prior to the commencement of any work by either party (or contractors or agents performing on their behalf), which work may directly or indirectly have an adverse effect on the Control Area of the other party.

9.0 Network Planning

In order for the Transmission Provider to plan, on an ongoing basis, to meet the Transmission Customer's requirements for Network Integration Transmission Service, the Transmission Customer shall provide, by September 1 of each year, updated information (current year and 10-year projection) for Network Load and Network Resources, as well as any other information reasonably necessary to plan for Network Load and Network Resources, as well as any other information reasonably necessary to plan for Network Integration Transmission Service. This type of information is consistent with the Transmission Provider's information requirements for planning to serve Native Load Customers. The data will be provided in a format consistent with that used by the Transmission Provider.

10.0 Transfer of Power and Energy Through Other Systems

Since the Transmission System is, and will be, directly or indirectly connected with other electric systems, it is recognized that, because of the physical and electrical

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AMORTIZATION OF CERTAIN REGULATORY	**)**	
ASSETS, AND OTHER RELIEF	**)**	

EXHIBIT__(SJB-5)

OF

STEPHEN J. BARON

CORRECTION TO REFLECT HOURLY 12 CP DEMANDS
East Kentucky Power Cooperative, Inc.
Allocation of Revenue Requirements to Rate Classes Excluding Environmental Surcharge Costs
TY 2019 - Pro Forma - Excludes ES and FAC

(a) Line No.	(b) Description	(c) Alloc. Factor	(d) Total ($)	(e) Rate B ($)	(f) Rate C ($)	(g) Rate E ($)	(h) Rate G ($)	(i) Contract ($)	(j) Steam ($)	(k) Rate TGP ($)
1	**Revenue**									
2	Total Revenue		422,130,617	27,170,310	7,931,946	342,414,808	10,833,171	23,685,067	4,516,945	5,578,370
3										
4	**Allocation of Revenue Requirements**									
5	Production Capacity			-						
6	Interruptible Credit [1]	Direct								
7	Remaining Prod. Capacity Rev. Req.	AED	172,575,237	8,849,977	2,571,816	147,983,798	3,824,479	9,345,166		
8	Subtotal Production Capacity		172,575,237	8,849,977	2,571,816	147,983,798	3,824,479	9,345,166	-	-
9	Production Energy									
10	Energy Cost Assigned to Rate TGP	Direct	4,743,510							4,743,510
11	On-Peak F&PP [2]	ON-ENG	24,129,992	1,964,131	518,568	19,611,815	878,322	1,157,155		
12	Off-Peak F&PP [2]	OFF-ENG	19,029,264	1,734,737	468,832	14,015,505	775,742	2,034,449		
13	Remaining Energy Revenue Req.	TOT-ENG	118,955,791	10,276,200	2,747,700	92,048,576	4,595,323	9,287,992		
14	Subtotal Production Energy		166,858,556	13,975,067	3,735,100	125,675,896	6,249,388	12,479,595	-	4,743,510
15	Steam Service	Direct	4,820,197						4,820,197	
16	Transmission									
17	Transm. Cost Assigned to Rate TGP [3]	Direct	834,860							834,860
18	Remaining Transm. Rev. Req.	12CP	104,172,870	6,011,051	1,591,603	88,228,791	2,533,409	5,808,017		
19	Subtotal Transmission		105,007,730	6,011,051	1,591,603	88,228,791	2,533,409	5,808,017	-	834,860
20	Distribution Substations	SUB	19,197,972	-	-	19,101,350	96,622	-	-	
21	Meters	METER	2,444,085	424,279	53,782	1,936,146	17,927	5,976	5,976	
22	Subtotal		470,903,778	29,260,374	7,952,302	382,925,981	12,721,825	27,638,754	4,826,173	5,578,370
23	Plus: FCA Factor Cost		-	-	-	-	-	-	-	-
24	Plus: FCA Base Cost		-	-	-	-	-	-	-	-
25	Subtotal		470,903,778	29,260,374	7,952,302	382,925,981	12,721,825	27,638,754	4,826,173	5,578,370
26	Plus: Environmental Surcharge		-	-	-	-	-	-	-	-
27	Total Revenue Requirements		470,903,778	29,260,374	7,952,302	382,925,981	12,721,825	27,638,754	4,826,173	5,578,370
28										
29	**Revenue Requirements less Revenue**		48,773,161	2,090,064	20,356	40,511,173	1,888,653	3,953,687	309,227	-
30	Increase (Decrease) as % of Present Revenue		11.6%	7.7%	0.3%	11.8%	17.4%	16.7%	6.8%	0.0%
31										
32										
33	**Average Cost per Unit / Rate Design Data**									
34	Production Capacity	/CP Billing kW		$4.84	$4.41	$6.18	$4.80	$4.79	$0.00	$0.00
35	Production Energy - Total Average Billing M	/MWh								
36	All Hours	/MWh		$12.81	$12.68	$12.92	$12.86	$12.59	$0.00	$25.92
37	On-Peak Hours	/MWh		$13.33	$13.19	$13.38	$13.38	$13.26	$0.00	$0.00
38	Off-Peak Hours	/MWh		$12.37	$12.24	$12.42	$12.42	$12.31	$0.00	$0.00
39	Transmission	/CP Billing kW		$3.29	$2.73	$3.68	$3.18	$2.97	$0.00	$1.75
40	Substations (Average All Capacities)	/sub/mon.				$4,928.11	$8,051.83		$0.00	
41	Metering	/meter/mon.		$497.98	$497.98	$497.98	$497.98	$497.98	$497.98	N/A
42	Total Demand Charges	/CP Billing kW		$8.13	$7.15	$9.862	$7.97	$7.76	$0.00	$1.75

1 Interruptible Credits are removed from the cost data for evaluation pursuant supplemental analysis.

2 In 2019, 55.91% of fuel and purchased energy cost occurred during the on-peak period, with the remaining 44.09% occuring during the off-peak period.

3 Assign the demand (transmission) charge per contract directly to Rate TGP.

COMMONWEALTH OF KENTUCKY

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APPROVAL OF DEPRECIATION STUDY,	**)**	
AMORTIZATION OF CERTAIN REGULATORY	**)**	
ASSETS, AND OTHER RELIEF	**)**	

EXHIBIT__(SJB-6)

OF

STEPHEN J. BARON

ELECTRIC UTILITY
COST ALLOCATION MANUAL

January, 1992

NATIONAL ASSOCIATION OF
REGULATORY UTILITY COMMISSIONERS

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B. Energy Weighting Methods

There is evidence that energy loads are a major determinant of production plant costs. Thus, cost of service analysis may incorporate energy weighting into the treatment of production plant costs. One way to incorporate an energy weighting is to classify part of the utility's production plant costs as energy-related and to allocate those costs to classes on the basis of class energy consumption. Table 4-4 shows allocators for the example utility for total energy, on-peak energy, and off-peak energy use.

In some cases, an energy allocator (annual KWH consumption or average demand) is used to allocate part of the production plant costs among the classes, but part or all of these costs remain classified as demand-related. Such methods can be characterized as partial energy weighting methods in that they take the first step of allocating some portion of production plant costs to the classes on the basis of their energy loads but do not take the second step of classifying the costs as energy- related.

1. Average and Excess Method

Objective: The cost of service analyst may believe that average demand rather than coincident peak demand is a better allocator of production plant costs. The average and excess method is an appropriate method for the analyst to use. The method allocates production plant costs to rate classes using factors that combine the classes' average demands and non-coincident peak (NCP) demands.

Data Requirements: The required data are: the annual maximum and average demands for each customer class and the system load factor. All production plant costs are usually classified as demand-related. The allocation factor consists of two parts. The first component of each class's allocation factor is its proportion of total average demand (or energy consumption) times the system load factor. This effectively uses an average demand or total energy allocator to allocate that portion of the utility's generating capacity that would be needed if all customers used energy at a constant 100 percent load factor. The second component of each class's allocation factor is called the "excess demand factor." It is the proportion of the difference between the sum of all classes' non-coincident peaks and the system average demand. The difference may be negative for curtailable rate classes. This component is multiplied by the remaining proportion of production plant -- i.e., by 1 minus the system load factor -- and then added to the first component to obtain the "total allocator." Table 4-10A shows the derivation of the allocation factors and the resulting allocation of production plant costs using the average and excess method.

TABLE 4-10A

CLASS ALLOCATION FACTORS AND ALLOCATED PRODUCTION PLANT REVENUE REQUIREMENT USING THE AVERAGE AND EXCESS METHOD

Class Rate	Demand Allocation Factor - NCP MW	Average Demand (MW)	Excess Demand (NCP MW - Avg. MW)	Average Demand Component of Alloc. Factor	Excess Demand Component of Alloc. Factor	Total Allocation Factor (%)	Class Production Plant Revenue Requirement
DOM	5,357	2,440	2,917	17.95	18.51	36.46	386,683,685
LSMP	5,062	2,669	2,393	19.64	15.18	34.82	369,289,317
LP	3,385	2,459	926	18.09	5.88	23.97	254,184,071
AG&P	572	254	318	1.87	2.02	3.89	41,218,363
SL	126	58	68	0.43	0.43	0.86	9,101,564
TOTAL	14,502	7,880	6,622	57.98	42.02	100.00	$1,060,476,000

Notes: The system load factor is 57.98 percent, calculated by dividing the average demand of 7,880 MW by the systen coincident peak demand of 13,591 MW. This example shows production plant classified as demand-related.

Some columns may not add to indicated totals due to rounding.

If your objective is -- as it should be using this method --to reflect the impact of average demand on production plant costs, then it is a mistake to allocate the excess demand with a coincident peak allocation factor because it produces allocation factors that are identical to those derived using a CP method. Rather, use the NCP to allocate the excess demands.

The example on Table 4-10B illustrates this problem. In the example, the excess demand component of the allocation factor for the Street Lighting and Outdoor Lighting (SL/OL) class is negative and reduces the class's allocation factor to what it would be if a single CP method were used in the first place. (See third column of Table 4-3.)

TABLE 4-10B

CLASS ALLOCATION FACTORS AND ALLOCATED PRODUCTION PLANT REVENUE REQUIREMENT USING THE AVERAGE AND EXCESS METHOD (SINGLE CP DEMAND FACTOR)

Rate Class	Demand Allocation Factor - Single CP NCP MW	Average Demand (MW)	Excess Demand (Single CP MW - Avg. MW)	Average Demand Component of Allocation Factor	Excess Demand Component of Allocation Factor	Total Allocation Factor (%)	Class Production Plant Revenue Requirement
DOM	4,735	2,440	2,295	17.95	16.89	34.84	369,461,692
LSMP	5,062	2,669	2,393	19.64	17.61	37.25	394,976,787
LP	3,347	2,459	888	18.09	6.53	24.63	261,159,089
AG&P	447	254	193	1.87	1.42	3.29	34,878,432
SL	0	58	-58	0.43	-0.43	0.00	0
TOTAL	13,591	7,880	5,711	57.98	42.02	100.00	$1,060,476,000

Notes: The system load factor is 57.98 percent, calculated by dividing the average demand of 7,880 MW by the systen coincident peak demand of 13,591 MW. This example shows all production plant classified as demand-related. Note that the total allocation factors are exactly equal to those derived using the single coincident peak method shown in the third column of Table 4-3.

Some columns may not add to indicated totals due to rounding.

Some analysts argue that the percentage of total production plant that is equal to the system load factor percentage should be classified as energy-related and not demand-related. This could be important because, although classifying the system load factor percentage as energy-related might not affect the allocation among classes, it could significantly affect the apportionment of costs within rate classes. Such a classification could also affect the allocation of production plant costs to interruptible service, if the utility or the regulatory authority allocated energy-related production plant costs but not demand-related production plant costs to the interruptible class. Table 4-10C presents the allocation factors and production plant revenue requirement allocations for an average and excess cost of service study with the system load factor percentage classified as energy-related.

TABLE 4-10C

CLASS ALLOCATION FACTORS AND ALLOCATED PRODUCTION PLANT REVENUE REQUIREMENT USING THE AVERAGE AND EXCESS METHOD

(AVERAGE DEMAND PROPORTION ALLOCATED ON ENERGY)

Rate Class	Energy Allocation Factor - Average MW	Energy Allocatn. Factor (%)	Energy-Related Production Plant Revenue Requirement	Excess Demand Allocation Factor (NCP MW - Avg. MW)	Excess Demand Alloctn. Factor (Percent)	Demand-Related Production Plant Revenue Requirement	Class Production Plant Revenue Requiremnt
DOM	2,440	30.96	190,387,863	2,917	44.05	196,294,822	386,682,685
LSMP	2,669	33.87	208,256,232	2,393	36.14	161,033,085	369,289,317
LP	2,459	31.21	191,870,391	926	13.98	62,313,680	254,184,071
AG&P	254	3.22	19,819,064	318	4.80	21,399,298	41,218,363
SL	58	0.74	4,525,613	68	1.03	4,575,951	9,101,564
TOTAL	7,880	100.00	614,859,163	6,622	100.00	445,616,837	1,060,476,000

Notes: The system load factor is 57.98 percent (7,880 MW/13,591 MW). Thus, 57.98 percent of total production plant revenue requirement is classified as energy-related and allocated to all classes on the basis of their proportions of average system demand. The remaining 42.02 percent is classified as demand-related and allocated to the classes according to their proportions of excess (NCP - average) demand, and allocated to the firm service classes according to their proportions of excess (NCP - average) demand.

Some columns may not add to indicated totals due to rounding.

2. Equivalent Peaker Methods

Objective: Equivalent peaker methods are based on generation expansion planning practices, which consider peak demand loads and energy loads separately in determining the need for additional generating capacity and the most cost-effective type of capacity to be added. They generally result in significant percentages (40 to 75 percent) of total production plant costs being classified as energy-related, with the results that energy unit costs are relatively high and the revenue responsibility of high load factor classes and customers is significantly greater than indicated by pure peak demand responsibility methods.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF:

THE ELECTRONIC APPLICATION OF	**)**	
EAST KENTUCKY POWER COOPERATIVE, INC.	**)**	
FOR A GENERAL ADJUSTMENT OF RATES,	**)**	**Case No. 2021-00103**
APPROVAL OF DEPRECIATION STUDY,	**)**	
AMORTIZATION OF CERTAIN REGULATORY	**)**	
ASSETS, AND OTHER RELIEF	**)**	

EXHIBIT__(SJB-7)

OF

STEPHEN J. BARON

East Kentucky Power Cooperative, Inc.
Classification of Plant in Service Excluding Environmental Surcharge Costs
TY 2019 - Pro Forma - Excludes ES and FAC

(a) Line No.	(b) Acct. No.	(c) Description	(d) Allocation Factor	(e) Pro Forma Test Year [1] ($)	(f) Production Capacity ($)	(g) Production Energy ($)	(h) Production Steam Direct ($)	(i) Transm. ($)	(j) Distribution Substations ($)	(k) Distribution Meters ($)	(l) Comments
1											
8		**Production Plant**									
9		**Steam**									
10	310	Land & Land Rights	See Note	10,123,919	5,442,173	4,417,696	264,051				[3]
11	311	Struct. & Improve.	See Note	294,492,048	159,893,898	129,794,228	4,803,922				[3]
12	312	Boiler Plant Equip.	See Note	787,574,876	423,930,805	344,126,777	19,517,295				[3]
13	313	Engines & Gen.	See Note	-	-	-	-				[3]
14	314	Turbogenerator Units	See Note	253,537,267	139,940,364	113,596,903	-				[3]
15	315	Access. Elec. Equip.	See Note	68,280,062	37,175,550	30,177,335	927,177				[3]
16	316	Misc. Plant Equipment	See Note	12,027,681	6,572,629	5,335,346	119,706				[3]
17	317	Asset Retirement	See Note	52,983,580	28,760,235	23,346,185	877,160				
18		Subtotal		1,479,019,434	801,715,653	650,794,469	26,509,311	-	-	-	
98	310-316	Production Plant--Steam		1,479,019,434	801,715,653	650,794,469	26,509,311	-	-	-	L18
99			PROD_STM_PLNT	1.000000	0.542059	0.440018	0.017924	-	-	-	
100											
101		Average and Excess	PROD_CAP	1.000000	0.551952	0.448048					

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF:

THE ELECTRONIC APPLICATION OF	**)**	
EAST KENTUCKY POWER COOPERATIVE, INC.	**)**	
FOR A GENERAL ADJUSTMENT OF RATES,	**)**	**Case No. 2021-00103**
APPROVAL OF DEPRECIATION STUDY,	**)**	
AMORTIZATION OF CERTAIN REGULATORY	**)**	
ASSETS, AND OTHER RELIEF	**)**	

EXHIBIT__(SJB-8)

OF

STEPHEN J. BARON

CORRECTION TO REMOVE AED DOUBLE COUNTING OF AVERAGE DEMAND
East Kentucky Power Cooperative, Inc.
Allocation of Revenue Requirements to Rate Classes Excluding Environmental Surcharge Costs
TY 2019 - Pro Forma - Excludes ES and FAC

(a) Line No.	(b) Description	(c) Alloc. Factor	(d) Total ($)	(e) Rate B ($)	(f) Rate C ($)	(g) Rate E ($)	(h) Rate G ($)	(i) Contract ($)	(j) Steam ($)	(k) Rate TGP ($)
1	**Revenue**									
2	Total Revenue		422,130,617	27,170,310	7,931,946	342,414,808	10,833,171	23,685,067	4,516,945	5,578,370
3										
4	**Allocation of Revenue Requirements**									
5	Production Capacity			-						
6	Interruptible Credit [1]	Direct								
7	Remaining Prod. Capacity Rev. Req.	AED	232,641,693	11,930,296	3,466,962	199,490,970	5,155,625	12,597,840		
8	Subtotal Production Capacity		232,641,693	11,930,296	3,466,962	199,490,970	5,155,625	12,597,840	-	-
9	Production Energy									
10	Energy Cost Assigned to Rate TGP	Direct	4,743,510							4,743,510
11	On-Peak F&PP [2]	ON-ENG	24,129,992	1,964,131	518,568	19,611,815	878,322	1,157,155		
12	Off-Peak F&PP [2]	OFF-ENG	19,029,264	1,734,737	468,832	14,015,505	775,742	2,034,449		
13	Remaining Energy Revenue Req.	TOT-ENG	58,889,335	5,087,256	1,360,255	45,568,857	2,274,925	4,598,041		
14	Subtotal Production Energy		106,792,100	8,786,124	2,347,655	79,196,177	3,928,989	7,789,645	-	4,743,510
15	Steam Service	Direct	4,820,197						4,820,197	
16	Transmission									
17	Transm. Cost Assigned to Rate TGP [3]	Direct	834,860							834,860
18	Remaining Transm. Rev. Req.	12CP	104,172,870	5,953,203	1,608,084	87,016,749	2,496,450	7,098,384		
19	Subtotal Transmission		105,007,730	5,953,203	1,608,084	87,016,749	2,496,450	7,098,384	-	834,860
20	Distribution Substations	SUB	19,197,972	-	-	19,101,350	96,622	-	-	
21	Meters	METER	2,444,085	424,279	53,782	1,936,146	17,927	5,976	5,976	
22	Subtotal		470,903,778	27,093,901	7,476,483	386,741,392	11,695,614	27,491,845	4,826,173	5,578,370
23	Plus: FCA Factor Cost		-	-	-	-	-	-	-	-
24	Plus: FCA Base Cost		-	-	-	-	-	-	-	-
25	Subtotal		470,903,778	27,093,901	7,476,483	386,741,392	11,695,614	27,491,845	4,826,173	5,578,370
26	Plus: Environmental Surcharge		-	-	-	-	-	-	-	-
27	Total Revenue Requirements		470,903,778	27,093,901	7,476,483	386,741,392	11,695,614	27,491,845	4,826,173	5,578,370
28										
29	**Revenue Requirements less Revenue**		48,773,161	(76,408)	(455,463)	44,326,584	862,443	3,806,778	309,227	-
30	Increase (Decrease) as % of Present Revenue		11.6%	-0.3%	-5.7%	12.9%	8.0%	16.1%	6.8%	0.0%
31										
32										
33	**Average Cost per Unit / Rate Design Data**									
34	Production Capacity	/CP Billing kW		$6.53	$5.95	$8.33	$6.46	$6.45	$0.00	$0.00
35	Production Energy - Total Average Billing M	/MWh								
36	All Hours	/MWh		$8.05	$7.97	$8.14	$8.09	$7.86	$0.00	$25.92
37	On-Peak Hours	/MWh		$8.57	$8.48	$8.61	$8.61	$8.53	$0.00	$0.00
38	Off-Peak Hours	/MWh		$7.61	$7.54	$7.64	$7.64	$7.57	$0.00	$0.00
39	Transmission	/CP Billing kW		$3.26	$2.76	$3.63	$3.13	$3.64	$0.00	$1.75
40	Substations (Average All Capacities)	/sub/mon.				$4,928.11	$8,051.83		$0.00	
41	Metering	/meter/mon.		$497.98	$497.98	$497.98	$497.98	$497.98	$497.98	N/A
42	Total Demand Charges	/CP Billing kW		$9.79	$8.71	$11.962	$9.60	$10.09	$0.00	$1.75

[1] Interruptible Credits are removed from the cost data for evaluation pursuant supplemental analysis.

[2] In 2019, 55.91% of fuel and purchased energy cost occurred during the on-peak period, with the remaining 44.09% occuring during the off-peak period.

[3] Assign the demand (transmission) charge per contract directly to Rate TGP.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF:

THE ELECTRONIC APPLICATION OF	**)**	
EAST KENTUCKY POWER COOPERATIVE, INC.	**)**	
FOR A GENERAL ADJUSTMENT OF RATES,	**)**	**Case No. 2021-00103**
APPROVAL OF DEPRECIATION STUDY,	**)**	
AMORTIZATION OF CERTAIN REGULATORY	**)**	
ASSETS, AND OTHER RELIEF	**)**	

EXHIBIT__(SJB-9)

OF

STEPHEN J. BARON

CORRECTION TO REMOVE NUCOR GALVANIZING LINE DEMAND, ENERGY AND REVENUES
East Kentucky Power Cooperative, Inc.
Allocation of Revenue Requirements to Rate Classes Excluding Environmental Surcharge Costs
TY 2019 - Pro Forma - Excludes ES and FAC

(a) Line No.	(b) Description	(c) Alloc. Factor	(d) Total ($)	(e) Rate B ($)	(f) Rate C ($)	(g) Rate E ($)	(h) Rate G ($)	(i) Contract ($)	(j) Steam ($)	(k) Rate TGP ($)
1	**Revenue**									
2	Total Revenue		421,674,021	27,170,310	7,931,946	342,414,808	10,833,171	23,228,471	4,516,945	5,578,370
3										
4	**Allocation of Revenue Requirements**									
5	Production Capacity			-						
6	Interruptible Credit [1]	Direct								
7	Remaining Prod. Capacity Rev. Req.	AED	172,384,263	8,858,633	2,575,941	148,666,728	3,827,177	8,455,783		
8	Subtotal Production Capacity		172,384,263	8,858,633	2,575,941	148,666,728	3,827,177	8,455,783	-	-
9	Production Energy									
10	Energy Cost Assigned to Rate TGP	Direct	4,743,510							4,743,510
11	On-Peak F&PP [2]	ON-ENG	24,139,786	1,966,395	519,166	19,634,427	879,335	1,140,462		
12	Off-Peak F&PP [2]	OFF-ENG	19,024,466	1,736,753	469,377	14,031,789	776,643	2,009,905		
13	Remaining Energy Revenue Req.	TOT-ENG	118,955,791	10,287,378	2,750,689	92,148,704	4,600,322	9,168,698		
14	Subtotal Production Energy		166,863,552	13,990,526	3,739,232	125,814,920	6,256,300	12,319,065	-	4,743,510
15	Steam Service	Direct	4,815,201						4,815,201	
16	Transmission									
17	Transm. Cost Assigned to Rate TGP [3]	Direct	834,860							834,860
18	Remaining Transm. Rev. Req.	12CP	104,172,870	5,966,650	1,611,716	87,213,301	2,502,089	6,879,114		
19	Subtotal Transmission		105,007,730	5,966,650	1,611,716	87,213,301	2,502,089	6,879,114	-	834,860
20	Distribution Substations	SUB	19,197,972	-	-	19,101,350	96,622	-	-	
21	Meters	METER	2,444,085	424,279	53,782	1,936,146	17,927	5,976	5,976	
22	Subtotal		470,712,804	29,240,088	7,980,671	382,732,445	12,700,116	27,659,938	4,821,176	5,578,370
23	Plus: FCA Factor Cost		-	-	-	-	-	-	-	-
24	Plus: FCA Base Cost		-	-	-	-	-	-	-	-
25	Subtotal		470,712,804	29,240,088	7,980,671	382,732,445	12,700,116	27,659,938	4,821,176	5,578,370
26	Plus: Environmental Surcharge		-	-	-	-	-	-	-	-
27	Total Revenue Requirements		470,712,804	29,240,088	7,980,671	382,732,445	12,700,116	27,659,938	4,821,176	5,578,370
28										
29	**Revenue Requirements less Revenue**		49,038,782	2,069,778	48,725	40,317,637	1,866,944	4,431,467	304,231	-
30	Increase (Decrease) as % of Present Revenue		11.6%	7.6%	0.6%	11.8%	17.2%	19.1%	6.7%	0.0%
31										
32										
33	**Average Cost per Unit / Rate Design Data**									
34	Production Capacity	/CP Billing kW		$4.85	$4.42	$6.21	$4.80	$4.48	$0.00	$0.00
35	Production Energy - Total Average Billing M	/MWh								
36	All Hours	/MWh		$12.83	$12.69	$12.93	$12.88	$12.60	$0.00	$25.92
37	On-Peak Hours	/MWh		$13.34	$13.21	$13.40	$13.40	$13.27	$0.00	$0.00
38	Off-Peak Hours	/MWh		$12.38	$12.26	$12.44	$12.44	$12.32	$0.00	$0.00
39	Transmission	/CP Billing kW		$3.26	$2.77	$3.64	$3.14	$3.64	$0.00	$1.75
40	Substations (Average All Capacities)	/sub/mon.				$4,928.11	$8,051.83		$0.00	
41	Metering	/meter/mon.		$497.98	$497.98	$497.98	$497.98	$497.98	$497.98	N/A
42	Total Demand Charges	/CP Billing kW		$8.11	$7.19	$9.849	$7.94	$8.12	$0.00	$1.75

1 Interruptible Credits are removed from the cost data for evaluation pursuant supplemental analysis.
2 In 2019, 55.93% of fuel and purchased energy cost occurred during the on-peak period, with the remaining 44.07% occuring during the off-peak period.
3 Assign the demand (transmission) charge per contract directly to Rate TGP.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF:

THE ELECTRONIC APPLICATION OF	**)**	
EAST KENTUCKY POWER COOPERATIVE, INC.	**)**	
FOR A GENERAL ADJUSTMENT OF RATES,	**)**	**Case No. 2021-00103**
APPROVAL OF DEPRECIATION STUDY,	**)**	
AMORTIZATION OF CERTAIN REGULATORY	**)**	
ASSETS, AND OTHER RELIEF	**)**	

EXHIBIT__(SJB-10)

OF

STEPHEN J. BARON

CORRECTION OF ALL 3 COST OF SERVICE ERRORS: 12 CP, AED DOUBLE COUNTING, NUCOR GALVANIZING LINE

East Kentucky Power Cooperative, Inc.

Allocation of Revenue Requirements to Rate Classes Excluding Environmental Surcharge Costs

TY 2019 - Pro Forma - Excludes ES and FAC

(a) Line No.	(b) Description	(c) Alloc. Factor	(d) Total ($)	(e) Rate B ($)	(f) Rate C ($)	(g) Rate E ($)	(h) Rate G ($)	(i) Contract ($)	(j) Steam ($)	(k) Rate TGP ($)
1	**Revenue**									
2	Total Revenue		421,674,021	27,170,310	7,931,946	342,414,808	10,833,171	23,228,471	4,516,945	5,578,370
3										
4	**Allocation of Revenue Requirements**									
5	Production Capacity			-						
6	Interruptible Credit [1]	Direct								
7	Remaining Prod. Capacity Rev. Req.	AED	232,450,719	11,945,380	3,473,515	200,468,925	5,160,739	11,402,159		
8	Subtotal Production Capacity		232,450,719	11,945,380	3,473,515	200,468,925	5,160,739	11,402,159	-	-
9	Production Energy									
10	Energy Cost Assigned to Rate TGP	Direct	4,743,510							4,743,510
11	On-Peak F&PP [2]	ON-ENG	24,139,786	1,966,395	519,166	19,634,427	879,335	1,140,462		
12	Off-Peak F&PP [2]	OFF-ENG	19,024,466	1,736,753	469,377	14,031,789	776,643	2,009,905		
13	Remaining Energy Revenue Req.	TOT-ENG	58,889,335	5,092,790	1,361,735	45,618,425	2,277,400	4,538,985		
14	Subtotal Production Energy		106,797,096	8,795,938	2,350,278	79,284,641	3,933,378	7,689,352	-	4,743,510
15	Steam Service	Direct	4,815,201						4,815,201	
16	Transmission									
17	Transm. Cost Assigned to Rate TGP [3]	Direct	834,860							834,860
18	Remaining Transm. Rev. Req.	12CP	104,172,870	6,015,145	1,592,687	88,288,882	2,535,134	5,741,022		
19	Subtotal Transmission		105,007,730	6,015,145	1,592,687	88,288,882	2,535,134	5,741,022	-	834,860
20	Distribution Substations	SUB	19,197,972	-	-	19,101,350	96,622	-	-	
21	Meters	METER	2,444,085	424,279	53,782	1,936,146	17,927	5,976	5,976	
22	Subtotal		470,712,804	27,180,741	7,470,262	389,079,945	11,743,800	24,838,509	4,821,176	5,578,370
23	Plus: FCA Factor Cost		-	-	-	-	-	-	-	-
24	Plus: FCA Base Cost		-	-	-	-	-	-	-	-
25	Subtotal		470,712,804	27,180,741	7,470,262	389,079,945	11,743,800	24,838,509	4,821,176	5,578,370
26	Plus: Environmental Surcharge		-	-	-	-	-	-	-	-
27	Total Revenue Requirements		470,712,804	27,180,741	7,470,262	389,079,945	11,743,800	24,838,509	4,821,176	5,578,370
28										
29	**Revenue Requirements less Revenue**		49,038,782	10,432	(461,684)	46,665,137	910,629	1,610,037	304,231	-
30	Increase (Decrease) as % of Present Revenue		11.6%	0.0%	-5.8%	13.6%	8.4%	6.9%	6.7%	0.0%
31										
32										
33	**Average Cost per Unit / Rate Design Data**									
34	Production Capacity	/CP Billing kW		$6.54	$5.96	$8.37	$6.47	$5.98	$0.00	$0.00
35	Production Energy - Total Average Billing M	/MWh								
36	All Hours	/MWh		$8.06	$7.98	$8.15	$8.10	$7.87	$0.00	$25.92
37	On-Peak Hours	/MWh		$8.58	$8.49	$8.62	$8.62	$8.54	$0.00	$0.00
38	Off-Peak Hours	/MWh		$7.62	$7.54	$7.65	$7.65	$7.58	$0.00	$0.00
39	Transmission	/CP Billing kW		$3.29	$2.73	$3.69	$3.18	$3.01	$0.00	$1.75
40	Substations (Average All Capacities)	/sub/mon.				$4,928.11	$8,051.83		$0.00	
41	Metering	/meter/mon.		$497.98	$497.98	$497.98	$497.98	$497.98	$497.98	N/A
42	Total Demand Charges	/CP Billing kW		$9.83	$8.70	$12.056	$9.65	$8.99	$0.00	$1.75

[1] Interruptible Credits are removed from the cost data for evaluation pursuant supplemental analysis.

[2] In 2019, 55.93% of fuel and purchased energy cost occurred during the on-peak period, with the remaining 44.07% occuring during the off-peak period.

[3] Assign the demand (transmission) charge per contract directly to Rate TGP.