COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

Electronic Application Of Kentucky Power Company	)	
For (1) A General Adjustment Of Its Rates For	)	
Electric Service; (2) Approval Of Tariffs And Riders;	)	
(3) Approval Of Accounting Practices To Establish	)	Case No. 2020-00174
Regulatory Assets And Liabilities; (4) Approval Of A	)	
Certificate Of Public Convenience And Necessity,	)	
And (5) All Other Required Approvals And Relief	)	

REBUTTAL TESTIMONY OF

D. BRETT MATTISON

ON BEHALF OF KENTUCKY POWER COMPANY

REBUTTAL TESTIMONY OF
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CASE NO. 2020-00174

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REBUTTAL TESTIMONY OF
D. BRETT MATTISON ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, POSITION, AND BUSINESS ADDRESS.

A. My name is D. Brett Mattison. I am President and Chief Operating Officer of Kentucky Power Company ("Kentucky Power" or the "Company"). My business address is 1645 Winchester Avenue, Ashland, Kentucky 41101.

Q. ARE YOU THE SAME D. BRETT MATTISON WHO OFFERED DIRECT TESTIMONY IN THIS PROCEEDING?

A. Yes, I am.

II. PURPOSE OF REBUTTAL TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. The purpose of my rebuttal testimony is to respond, in part, to intervenor testimony regarding the return on equity ("ROE") that Kentucky Power is requesting in this case. I also respond to Office of the Attorney General of the Commonwealth of Kentucky and Kentucky Industrial Utility Customers, Inc. (jointly, "AG/KIUC") Witness Kollen's recommendations regarding the other mitigation measures the Company has proposed in this case – specifically, the one-year unprotected excess accumulated deferred federal income tax ("ADFIT") rate increase offset and conditional Capacity Charge tariff discontinuation. Finally, I briefly address the treatment in this case of the Company's customer debt relief proposal in Case No. 2020-00176.

III. RETURN ON EQUITY AND OTHER RATE INCREASE MITIGATION PROPOSALS

Q. HOW DO YOU RESPOND TO JOINT INTERVENORS WITNESS OWEN'S CONTENTION (AT PAGE 17) THAT THE COMPANY'S PROPOSED ROE DOES NOT TAKE INTO ACCOUNT THAT MEASURE'S IMPACT ON KENTUCKY POWER'S CUSTOMERS?

A. Mr. Owen's position is simply incorrect. As I explained during the September 30, 2020 FERC panel that Mr. Owen references, the Company takes seriously how its decisions affect customers. This is evidenced by, among other things, the Company's recent customer debt relief proposal that was the subject of Case No. 2020-00176. The mitigation measures proposed in this case – *i.e.*, the proposed ADFIT rate increase offset, the conditional discontinuation of the Capacity Charge tariff, and the selection of an ROE that is 30 basis points lower than that which the Company's ROE expert, Mr. McKenzie, testifies is warranted – also demonstrate that the Company has thoughtfully considered customer impacts, including the impact on customers of its requested 10.0% ROE.

Q. IS IT TRUE THAT THE ONLY REASON FOR THE COMPANY'S REQUESTED ROE IS "TO ATTRACT CAPITAL TO [ITS] INVESTMENTS," AS MR. OWEN ARGUES (AT PAGE 18)?

A. No, Mr. Owen's position is misinformed. Company Witness McKenzie is the Company's expert witness with regard to ROE issues and addresses Mr. Owen's arguments in greater detail in his Rebuttal Testimony (at pages 35-36). However, I will respond in part to Mr. Owen's suggestion that the Company's requested ROE is higher than a level that is sufficient to ensure its financial integrity. Kentucky Power's earnings since its last rate case refute Mr. Owen's assertion.

Q. WHAT ROE DID THE COMMISSION APPROVE IN KENTUCKY POWER'S LAST RATE CASE, CASE NO. 2017-00179?

A. The Commission authorized a 9.7 percent ROE.

Q. HAS KENTUCKY POWER EARNED ITS AUTHORIZED ROE?

A. No, it has not. The Company has never earned the 9.7% ROE authorized in its last rate case, and its earned ROE has steadily declined since third quarter 2018, as demonstrated in Figure DBM-1 below:

Figure DBM-1

Twelve Months Ended	Earned ROE
3/31/2018	6.9%
6/30/2018	8.7%
9/30/2018	9.2%
12/31/2018	9.0%
3/31/2019	8.6%
6/30/2019	7.6%
9/30/2019	7.8%
12/31/2019	7.4%
3/31/2020	6.7%
6/30/2020	5.7%
9/30/2020	5.3%

Despite the Company's prudent management of its operations and its continuing economic development efforts within its service territory, as I described in my Direct Testimony, customer counts, load, and electricity sales continue to decline. The COVID-19 pandemic has exacerbated the situation and further impaired the Company's earnings.

Q. ARE THE COMPANY'S EARNINGS SUFFICIENT TO ENSURE ITS FINANCIAL INTEGRITY?

A. No, Kentucky Power's existing rates are not providing it an opportunity to earn a reasonable return. The Company's earned ROE impacts Kentucky Power's financial integrity by impacting its access to capital and the cost of that capital. Continued earnings at the levels the Company has experienced for over more than the last year could weaken the Company's financial integrity, thereby limiting its ability to finance assets or undertake new projects, and making it more expensive to do so. As Mr. McKenzie explains in his Rebuttal Testimony (at page 35), a lower ROE than the Company requests, and certainly one lower than authorized in the Company's last rate case, "would send an unmistakable signal to the investment community as they consider whether to commit capital in Kentucky, and at what cost." Ultimately, that would only serve to further harm the Company's financial health, and increase costs to customers.

As I explained in my Direct Testimony, the Company made the difficult decision to file this case, recognizing the unprecedented economic condition in which customers, the Commonwealth, and the country found themselves this year, because Kentucky Power's financial health has been critically impacted by a declining customer base and declining usage. This fact is already reflected in the Company's earnings. The COVID-19 pandemic has caused load in Kentucky Power's territory to decline even further, further impairing the Company's earnings; those impacts predominantly occurred after the end of the Company's test year and are not reflected in the revenue requirement in this case.

Q. DO YOU HAVE ANY ADDITIONAL OBSERVATIONS BASED ON THE FOREGOING?

A. It is important that the Commission act in this case to protect Kentucky Power's ability to continue to provide safe and reliable electric service to its customers. The balanced and reasonable package of proposals the Company has offered in this case, summarized in my Direct Testimony, does just that, while also providing numerous tangible benefits to customers, as well as approximately $73.6 million in rate increase mitigation also to their benefit.

It would be unfair, and harmful to Kentucky Power, if the Commission were to modify the package of mitigation measures the Company has proposed in a way that impairs Kentucky Power's ability to invest in its service territory to benefit its customers. Any further erosion in the ROE negatively impacts Kentucky Power's ability to implement the other proposals it has made in this case, and will harm its financial wellbeing.

Q. DO YOUR STATEMENTS ABOVE HOLD TRUE FOR OTHER MITIGATION MEASURES THE COMPANY HAS OFFERED IN THIS CASE?

A. Yes, they do. They also apply to the other mitigation measures the Company has proposed, *i.e.*, the ADFIT offset of first year rate increase and conditional discontinuation of the collection of the Capacity Charge tariff. The suite of mitigation measures offered by Kentucky Power are a collective proposal, and they need to be considered together. To ensure the rates the Commission sets in this proceeding are fair, just, and reasonable, and do not further harm Kentucky Power, the Commission should not accept the proposals made by AG/KIUC Witness Kollen (at pages 47-49 and 57-58) to extend the ADFIT offset an additional 6 months and to discontinue the Capacity Charge tariff other than on the terms offered by Kentucky Power. Company Witnesses West, Messner, and Vaughan, respectively, discuss these issues further in their Rebuttal Testimony.

Q. DO YOU HAVE ANY RECOMMENDATIONS REGARDING HOW, IN THIS CASE, THE COMMISSION SHOULD TREAT THE COMPANY'S CUSTOMER DEBT RELIEF PROPOSAL MADE IN CASE NO. 2020-00176?

A. The Commission indicated in its October 2, 2020 order in Case No. 2020-00176, at page 7, that it believes this proceeding is the appropriate case in which to address the Company's proposal in Case No. 2020-00176 to utilize approximately $10.8 million of its unprotected excess ADFIT balance to eliminate customer arrearages as of May 28, 2020. Kentucky Power stands by its commitment in Case No. 2020-00176 and is willing to amortize that amount in the manner directed by the Commission in this case to address customer arrearages. Company Witnesses West's, Vaughan's, and Messner's Rebuttal Testimony addresses the other items the Commission indicated its order in Case No. 2020-00176 it would like the Company to address in this docket regarding its ADFIT proposals.

IV. CONCLUSION

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes, it does.

VERIFICATION

The undersigned, D. Brett Mattison, being duly sworn, deposes and says he is President & COO of Kentucky Power Company that he has personal knowledge of the matters set forth in the forgoing testimony and the information contained therein is true and correct to the best of his information, knowledge and belief after reasonable inquiry.

D. Brett Mattison

D. Brett Mattison

COMMONWEALTH OF KENTUCKY)
) Case No. 2020-00174
COUNTY OF BOYD)

Subscribed and sworn to before me, a Notary Public in and before said County and State, by D. Brett Mattison, this 3rd day of November 2020.

Trisha Nance

Notary Public

Notary ID Number: 632421

My Commission Expires: 9-26-2023

OFFICIAL SEAL
TRISHA NANCE
NOTARY PUBLIC - KENTUCKY
STATE-AT-LARGE
My Comm. Expires September 26, 2023
ID # 632421

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REBUTTAL TESTIMONY OF

STEPHEN D. BLANKENSHIP

ON BEHALF OF KENTUCKY POWER COMPANY

REBUTTAL TESTIMONY OF
STEPHEN D. BLANKENSHIP ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

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EXHIBITS

EXHIBIT	DESCRIPTION
EXHIBIT SDB- R1	Scatterplot/Meter Density Map of Locations of Meters in the Kentucky Power Service Territory – End of Useful Life on or after January 2021.
EXHIBIT SDB-R2	Company’s Response to AG/KIUC 1-89

REBUTTAL TESTIMONY OF
STEPHEN D. BLANKENSHIP ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS, AND PRESENT POSITION.

A. My name is Stephen D. Blankenship. My business address is 12333 Kevin Avenue, Ashland, Kentucky 41102. I am the Region Support Manager for Kentucky Power Company ("Kentucky Power" or the "Company"). Kentucky Power is a subsidiary of American Electric Power Company, Inc. ("AEP").

Q. ARE YOU THE SAME STEPHEN D. BLANKENSHIP WHO OFFERED DIRECT TESTIMONY IN THIS PROCEEDING?

A. Yes.

Q. ARE YOU SPONSORING ANY EXHIBITS IN THIS PROCEEDING?

A. Yes, I am sponsoring the following exhibits:

- **Exhibit SDB-R1** – Scatterplot/Meter Density Map of Locations of Meters in the Kentucky Power Service Territory – End of Useful Life on or after January 2021.

- **Exhibit SDB-R2** – Company's Response to AG/KIUC 1-89.

II. PURPOSE OF REBUTTAL TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. The purpose of my rebuttal testimony is to respond to portions of the testimony offered by Attorney General/Kentucky Industrial Utility Customers, Inc. witness Lane Kollen regarding the Company's request for a certificate of public convenience and necessity to deploy Advanced Metering Infrastructure ("AMI") meters. Specifically, I will address Mr. Kollen's assertions regarding the need to replace the Company's obsolete Automated Meter Reading ("AMR") meters and the benefits of the Company's proposed AMI deployment.

III. AMI DEPLOYMENT

Q. MR. KOLLEN CONTENDS THAT THE COMPANY'S "PROPOSED AMI AND RELATED INFRASTRUCTURE WILL NOT RESULT IN NET SAVINGS OR EVEN BREAKEVEN IN COMPARISON TO RETAINING ITS EXISTING AMR METERS AND RELATED INFRASTRUCTURE." HOW DO YOU RESPOND?

A. Mr. Kollen ignores the basis for the Company's proposal to begin replacing the existing AMR metering infrastructure with AMI metering in a systematic fashion. Although the Company has identified the substantial benefits resulting from implementation of AMI metering in my direct testimony (at p. 11-16), its proposal is not based on a formal cost-benefit study. Instead, the Company's proposal is based upon the recognition that it is unreasonable to sink additional capital dollars in an obsolete and increasingly unsupported metering technology as stated in my Direct Testimony (at p. 3-4) as a stop-gap solution to the need to address 10-15 year old population of AMR meters that are rapidly approaching the end of their operational life.

Q. DOES MR. KOLLEN DISPUTE THAT, EVEN IF THE COMPANY WERE TO ATTEMPT TO MAINTAIN ITS AMR METERING INFRASTRUCTURE BY INSTALLING RETIRED METERS FROM ITS AFFILIATES, KENTUCKY POWER WILL BE REQUIRED TO IMPLEMENT AMI METERING IN ONLY A FEW YEARS?

A. No. Thus, while noting that replacement meters and parts may be available from the Company's affiliates, he ignores the fact that these meters and parts for the most part are only slightly newer than Kentucky Power's existing inventory of AMR meters and parts. He likewise nowhere addresses the unnecessary cost and operational inefficiencies inherent with replacing an obsolete metering technology that is approaching the end of its operational life with only slightly newer equipment employing the same obsolete technology. Mr. Kollen, who is not an engineer, and who apparently has no experience in deploying or maintaining electric metering technology, offers no estimate of how long his proposed temporary solution would last or cost. He also ignores the fact that his apparent proposal would require the investment of capital dollars that could and should be directed toward obtaining for Kentucky Power's customers the benefits of AMI technology.

Q. DO YOU AGREE WITH MR. KOLLEN'S STATEMENT AT PAGE 62 OF HIS TESTIMONY THAT "AT LEAST ONE VENDOR CONTINUES TO MANUFACTURE THE TYPE OF METER … [KENTUCKY POWER] CURRENTLY USES"?

A. Mr. Kollen appears to misunderstand my Direct Testimony at pages 2-4. Kentucky Power's AMR meters, which operate on a Standard Consumption Messaging ("SCM") platform, are no longer being manufactured by any vendor and are no longer supported by their manufacturer. The only vendor in the industry that continues to support AMR metering only supports AMR on a platform that the Company does not have, known as SCM+. In order for that vendor to support the Company's AMR infrastructure, Kentucky Power would need to replace its existing SCM platform with an SCM+ platform. The Company preliminarily estimates that the cost to upgrade to the SCM+ platform would be approximately $22 million, which is equivalent to approximately 60% of the cost of its proposed AMI deployment.

Were the Company to make that significant additional investment in AMR technology, it would do so without realizing for customers any of the numerous benefits associated with AMI technology. It would also be relying upon one vendor to support the increasingly obsolete AMR technology, which could lead to increased meter and metering equipment, IT services, and software update costs – all of which would do nothing to avoid the need to replace the AMR meters with AMI meters and associated infrastructure in the near future. Kentucky Power also would be the sole company within the AEP system utilizing the SCM+ platform, and thus would lose the cost savings associated with economies of scale that are available to it in moving to industry standard AMI technology.

Q. DOES MR. KOLLEN CONTEND THAT THE COMPANY SHOULD REPLACE ITS EXISTING AMR METERING INFRASTRUCTURE WITH AMI METERING ON AN AD HOC BASIS AS THE EXISTING METERS FAIL?

A. No. He nowhere addresses my Direct Testimony at pages 11-16 regarding the operational and cost-savings benefits resulting from implementing AMI metering on a systematic basis. Nor does he contest the fact that because existing AMR meters approaching the end of their design life by January 2021 (*See* SDB-R1) are spread throughout the Company's service there is no practical way to implement AMI metering by replacing the existing AMR meters as they fail. Exhibit SDB-R1 shows the locations of AMR meters in the Company's service territory that will reach the end of their design life on or after January 2021; they are distributed in practically every county where Kentucky Power provides service.

IV. <u>COST-BENEFIT ANALYSIS</u>

Q. MR. KOLLEN ASSERTS, ON PAGE 61, THAT KENTUCKY POWER HAS NOT PERFORMED A COST/BENEFIT STUDY REGARDING ITS PROPOSED AMI DEPLOYMENT BECAUSE IT "SIMPLY CLAIMS THAT AN ECONOMIC STUDY IS NOT NECESSARY AND THAT IT HAS NO INTENTION TO PERFORM ONE." HOW DO YOU RESPOND?

A. Mr. Kollen misstates the Company's reasons for not performing a cost/benefit analysis, and selectively attaches, and mischaracterizes, the Company's data responses regarding that decision. Contrary to Mr. Kollen's testimony, the Company has fully explained that a cost/benefit analysis is unnecessary and would be infeasible and of little utility here. *See, e.g.,* Exhibit SDB-R2. The Company made the decision to move to AMI metering based upon the operational and technology considerations discussed above and in my Direct Testimony, primarily due to the age, condition, and obsolescence of AMR meters.

Additionally, many of the benefits associated with AMI are incremental to those obtained through the legacy AMR systems or processes that AMI is intended to replace or augment. For example, AMR displaced traditional meter reading using electro-mechanical meters. Aside from incremental meter reading benefits, additional benefits associated with AMI include the ability to remotely connect and disconnect meters and reduce the number of field trips (trip charges), as discussed in my Direct Testimony (at p. 9). The added benefit of migrating from a legacy AMR system to AMI represents an incremental impact on the AMI business case, meaning benefits originally realized with AMR will not be captured a second time and thus, although providing real benefits, would not be reflected in a cost/benefit analysis.

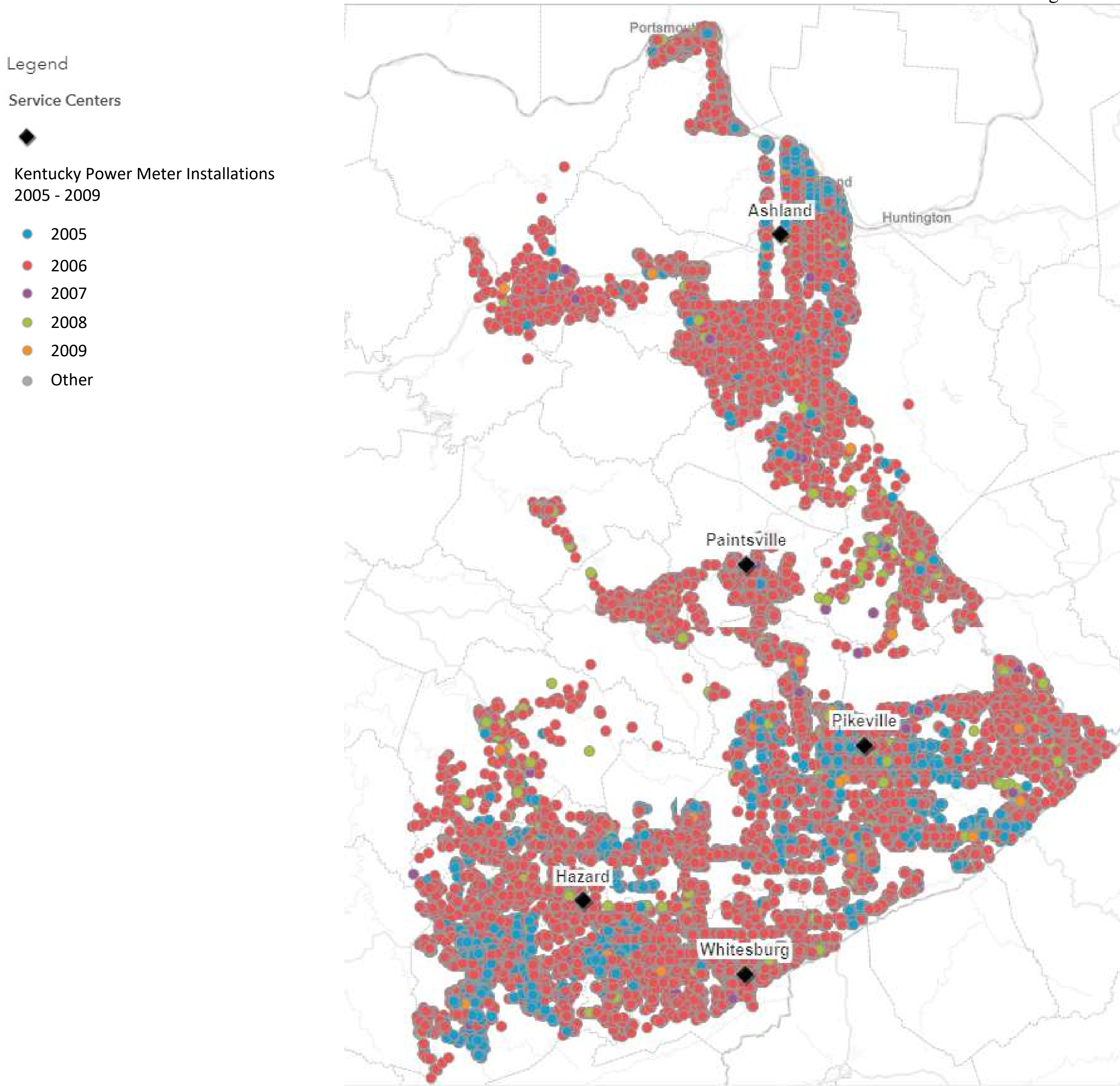
A cost/benefit analysis also would be of limited utility because of limitations associated with unverifiable assumptions and the challenges of assigning a quantitative value to unquantifiable benefits such as employee safety and customer satisfaction benefits related to AMI deployment, a consultant-conducted study intended to provide the type study Mr. Kollen apparently believes is necessary would be costly while potentially providing information not materially more reliable than the analysis conducted by the Company, particularly in light of the obsolescence of AMR technology. For example, the value a customer places on having greater control over their electric usage with AMI meters and the Home Energy Management system will vary by customer and preference. It is impossible to put an accurate value on a perception, but it is nonetheless a benefit available to all customers if they choose to avail themselves of it. The Company thus concluded, for these reasons, that a cost-benefit analysis comparing the deployment of AMR and AMI meters was not appropriate or necessary in this case.

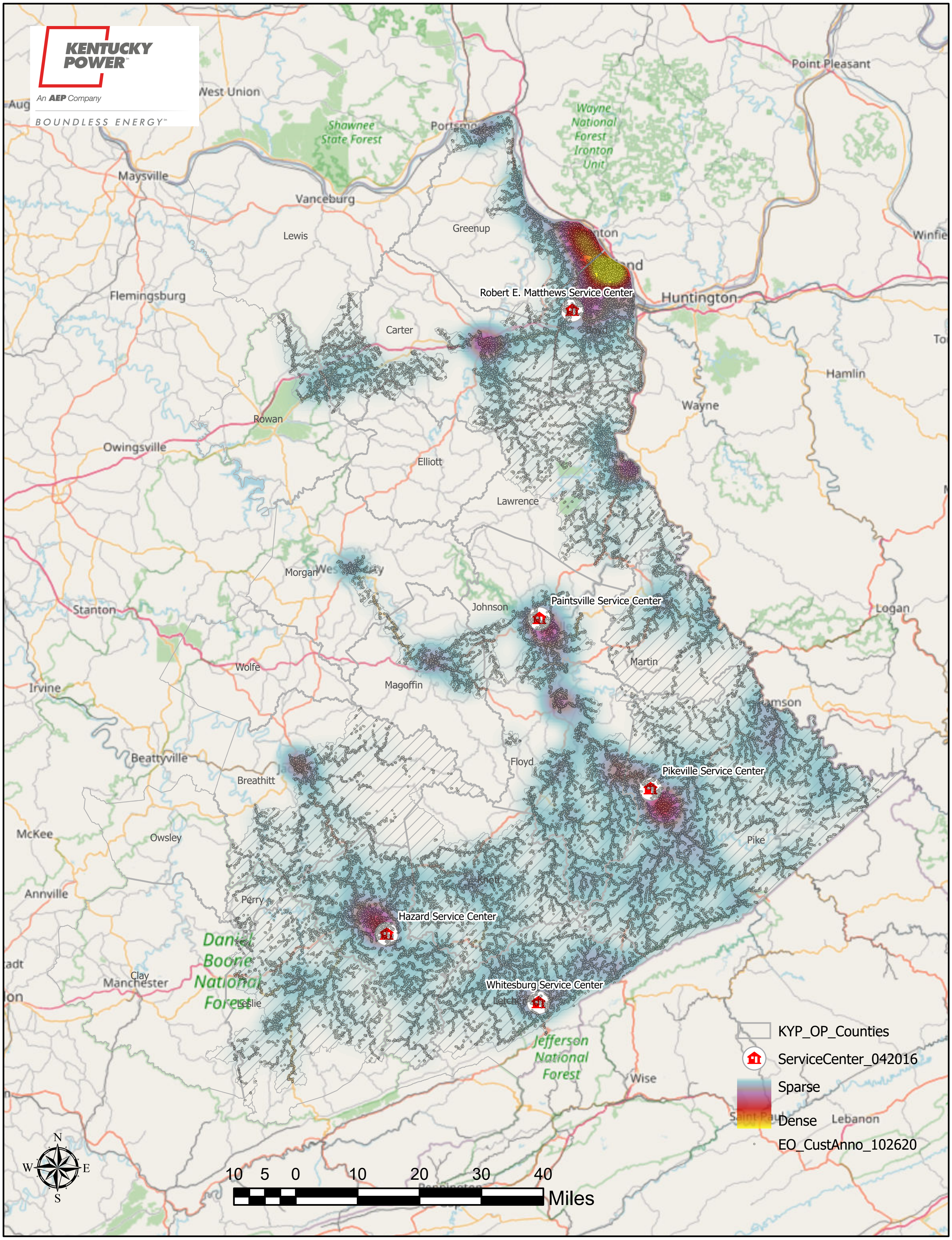
Q. IS MR. KOLLEN'S STATEMENT ON PAGE 63 THAT THERE IS "NO WAY FOR THE COMMISSION TO DETERMINE WHETHER THE 'CITED' BENEFITS OF THE PROPOSED AMI METERS ARE ACCURATE" CORRECT?

A. No. Again, this argument ignores the fact that the Company's reason for replacing its AMR meters is because the AMR meters are reaching the end of their useful life and are obsolete. Mr. Kollen ignores the numerous benefits associated with AMI technology that I described in my Direct Testimony (at p. 11-16), such as those associated with service reliability, service connection speed, customer access to usage information, customer control over usage and the cost of their electric service, labor and fleet expense reductions, reductions in collections and bad debt expense, and possible peak load reductions. The Company has provided considerable support for and documentation of the benefits associated with its proposed AMI deployment in this case. Additionally, as discussed in the Direct Testimony of Company Witness West (at p. 12), the Commission will have an opportunity to review the prudency of Kentucky Power's AMI deployment and the accuracy of the cited benefits of AMI through its annual review of the Company's Grid Modernization Rider. Mr. Kollen's concerns in this regard are unfounded.

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes, it does.


Legend
Service Centers
Kentucky Power Meter Installations
2005 - 2009
2005
2006
2007
2008
2009
Other
Ashland
Huntington
Paintsville
Pikeville
Hazard
Whitesburg


KENTUCKY POWER
An AEP Company
BOUNDLESS ENERGY
Robert E. Matthews Service Center
Paintsville Service Center
Pikeville Service Center
Hazard Service Center
Whitesburg Service Center
Greenup
Lewis
Carter
Rowan
Elliott
Lawrence
Morgan
Johnson
Martin
Magoffin
Wolfe
Floyd
Breathitt
Pike
Knott
Perry
Leslie
Owsley
Clay
Maysville
Vanceburg
Flemingsburg
Owingsville
Stanton
Irvine
Beattyville
McKee
Annville
Manchester
West Union
Shawnee State Forest
Wayne National Forest Ironton Unit
Point Pleasant
Huntington
Hamlin
Wayne
Logan
Daniel Boone National Forest
Jefferson National Forest
Wise
Lebanon
KYP_OP_Counties
ServiceCenter_042016
Sparse
Dense
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DATA REQUEST

AG_KIUC_1_089 Provide a copy of all cost/benefit analyses performed in support of the proposed AMI. If none were performed, then so state and explain why the Company determined that such analyses were not necessary.

RESPONSE

A cost-benefit study was not performed in connection with the Company's proposed deployment of AMI technology. The Company's existing AMR meters are reaching the end of their useful life and must be replaced. As explained in the Direct Testimony of Mr. Blankenship, 75% of the AMR meters deployed in the Company's service territory will reach the end of their design life by the start of the proposed AMI deployment. Because AMR meters are being phased out across the industry, and are manufactured only by a single vendor, the Company has determined that it would not be beneficial to customers replace existing AMR meters by deploying additional AMR meters, which are increasingly obsolete, and becoming an unsupported technology. Please refer to the Testimony of Company Witness Blankenship at pages 3-5.

The Company further recognized that over the past decade AMI technology has matured, its pricing stabilized, and its importance to system reliability has increased. Additionally, although of limited utility because of limitations associated with unverifiable assumptions and the challenges of assigning a quantitative value to unquantifiable benefits such as the employee safety and customer satisfaction benefits related to AMI deployment, a consultant-conducted study intended to provide the type of information described in the request would be costly while potentially providing information not materially more reliable than the analysis conducted by the Company, particularly in light of the obsolescence of AMR technology. For example, the value a customer places on having greater control over their electric usage with AMI meters and the Home Energy Management system will vary by customer and preference. It is impossible to put an accurate value on a perception, but it is nonetheless a benefit available to all customers if they choose to avail themselves of it. The Company thus concluded that a cost-benefit analysis comparing the deployment of AMR and AMI meters was not warranted.

The Company plans to employ a competitive bidding process for materials and outside services to obtain the lowest reasonable cost for its AMI deployment. AEP’s size allows it to leverage its "economies of scale" resulting in low cost pricing of material and labor. AEP has a highly centralized distribution model that delivers standardization of equipment, materials, and processes. These highly standardized designs are not only more efficient to design and construct, but they also provide Kentucky Power with greater negotiating leverage with its suppliers and service providers.

Now that AMR is obsolete and at the end of its useful life, AMI is the appropriate next step to continue to provide customers with grid modernization benefits. The four-year deployment plan that the Company proposes is an efficient and effective way to provide customers the benefits from AMI technology, which include reductions in Meter Revenue Operations spending, reductions in credit and collections and bad debt expenses on past due accounts, possible peak load reductions, reduced calls, reduced estimated meter readings, reduced Commission complaints, ability to remotely connect and disconnect meters, reliability improvements, and reduced truck roll-out for open and close account orders. Please see the Direct Testimony of Company Witness Blankenship, at pages 11-16 for the types of benefits that are not readily quantifiable.

Witness: Stephen D. Blankenship

VERIFICATION

The undersigned, Stephen D. Blankenship, being duly sworn, deposes and says he is a Region Support Manager for Kentucky Power Company that he has personal knowledge of the matters set forth in the forgoing testimony and the information contained therein is true and correct to the best of his information, knowledge and belief after reasonable inquiry.

Stephen D. Blankenship

Stephen D. Blankenship

COMMONWEALTH OF KENTUCKY)
) Case No. 2020-00174
COUNTY OF BOYD)

Subscribed and sworn to before me, a Notary Public in and before said County and State, by Stephen D. Blankenship, this 3rd day of November 2020.

Trisha Nance

Notary Public

Notary ID Number: 632421

My Commission Expires: 9-26-2023

OFFICIAL SEAL
TRISHA NANCE
NOTARY PUBLIC - KENTUCKY
STATE-AT-LARGE
My Comm. Expires September 26, 2023
ID # 632421

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

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REBUTTAL TESTIMONY OF

BRIAN K. WEST

ON BEHALF OF KENTUCKY POWER COMPANY

REBUTTAL TESTIMONY OF
BRIAN K. WEST ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

CASE NO. 2020-00174

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BRIAN K. WEST ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, POSITION, AND BUSINESS ADDRESS.

A. My name is Brian K. West. My position is Director of Regulatory Services, Kentucky Power Company ("Kentucky Power" or the "Company"). My business address is 1645 Winchester Avenue, Ashland, Kentucky 41101.

Q. ARE YOU THE SAME BRIAN K. WEST WHO OFFERED DIRECT TESTIMONY IN THIS PROCEEDING?

A. Yes.

II. PURPOSE OF REBUTTAL TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. The purpose of my rebuttal testimony is to respond to certain recommendations in the Direct Testimony of Lane Kollen for the Office of the Attorney General of the Commonwealth of Kentucky and Kentucky Industrial Utility Customers, Inc. (jointly, "AG/KIUC"), the Direct Testimony of Lisa Perry for Walmart Inc., and the Direct Testimony of James Owen and Joshua Bills for Joint Intervenors (Mountain Association, Kentuckians for the Commonwealth, and the Kentucky Solar Energy Society). Specifically, I address certain proposals regarding the offset to approved rates raised by AG/KIUC Witness Kollen; recommendations by several intervening parties with regard to the Grid Modernization Rider and Advanced Metering Infrastructure; a revenue adjustment related to EEI dues raised by AG/KIUC Witness Kollen; and certain other issues regarding Demand-Side Management programs and net metering interconnection guidelines raised by Joint Intervenors Witnesses Owen and Bills.

III. YEAR ONE OFFSET TO APPROVED RATES

Q. WITH REGARD TO MR. KOLLEN'S RECOMMENDATIONS AT PAGES 47-49 OF HIS TESTIMONY ON THE USE OF UNPROTECTED EXCESS ADFIT TO OFFSET BASE RATE INCREASES, HOW DO YOU RESPOND?

A. The Company appreciates AG/KIUC's support for its proposal to use unprotected excess ADFIT to offset all rate increases for the first year (2021) new base rates are in effect. This benefit customers and allow additional time for economic recovery from the COVID-19 pandemic. As for Mr. Kollen's supplemental proposal to use an additional amount of unprotected excess ADFIT to mitigate 50% of the net increase in base rates in the second year (2022), the Company opposes this proposed additional mitigation measure. One of the factors credit rating agencies use in determining company ratings is cash flow. The Company's proposal to offset the first year base rate increase using excess unprotected ADFIT will negatively influence cash flow and put pressure on the Company's credit metrics. The Company can accept these impacts for one year, but it cannot bear the cash flow pressure and downgrade risk over a sustained time period. Company Witness Messner further discusses this in his rebuttal testimony.

Q. CAN YOU PROVIDE AN ESTIMATE OF THE REMAINING AMORTIZATION PERIOD FOR TARIFF F.T.C.?

A. Yes. Figure 1 below shows an estimated amortization period for Tariff F.T.C. Included in the calculation is $10.8 million to be used for customer debt relief as may be determined in this case by the Commission. In its October 2, 2020 order in Case No. 2020-00176, at page 7, the Commission made clear that it prefers to address Kentucky Power's proposal in that case as part of this proceeding. Figure 1 assumes the first-year total net revenue increase is offset, that the Commission applies $10.8 million of ADFIT for customer debt relief, and that the amortization rates remain the same, as the Company proposed in its Direct Testimony.

Figure 1

Estimate of Forward Use of Excess Unprotected ADFIT Balance			
ADFIT Use	**2021**	**2022**	**2023**
Rate Case Offset	$ 48,345,038		
Debt Foregiveness	$ 10,800,000		
Fed Tax Cut Rider	$ 6,951,693	$ 6,951,693	$ 6,951,693
Total	$ 66,096,731	$ 6,951,693	$ 6,951,693
EOY ADFIT Bal	14,914,455	7,962,761	1,011,068

Estimate of Forward Use of Excess Unprotected ADFIT Balance - Revenue Basis			
ADFIT Use	**2021**	**2022**	**2023**
Rate Case Offset	$ 65,001,789		
Debt Foregiveness	$ 14,521,021		
Fed Tax Cut Rider	$ 9,346,823	$ 9,346,823	$ 9,346,823
Total Rate Credit	$ 88,869,633	$ 9,346,823	$ 9,346,823

IV. GRID MODERNIZATION RIDER AND AMI METERING

Q. AG/KIUC, WALMART, AND THE JOINT INTERVENORS MAKE CERTAIN RECOMMENDATIONS WITH REGARD TO THE PROPOSED GRID MODERNIZATION RIDER ("GMR"). HOW DO YOU RESPOND?

A. I disagree with intervenors' recommendation that the Commission reject the GMR. Over the years, the Company has invested in its distribution system, making upgrades to facilities and equipment to continue to provide safe and reliable service to its customers. However, there are new technologies that can usher in a step change in the capabilities of the Company's distribution system bringing it to the standards of today with the installation of various digital technologies and equipment. Company Witness Phillips, at page 31 of his Direct Testimony, explains the purpose of the GMR and the critical need for a recovery mechanism other than base rates to support projects that will improve and modernize the aging distribution grid.

At the core of this effort, and the project that must be completed first, is an advanced metering infrastructure ("AMI") deployment. AMI infrastructure provides the communications backbone that will enable future projects to modernize the grid. With the communications backbone in place, other devices will permit the Company to monitor the electric service it provides to customers in a way never possible before. It will make possible for the Company to identify a failing transformer before it fails and replace it, improving reliability and the customer experience. Also, advanced systems like Supervisory Control and Data Acquisition ("SCADA") and Distribution Automation Circuit Reconfiguration ("DACR"), in connection with AMI, will provide the Company with unprecedented control and insight into the health of the grid.

Q. WHY IS THE COMPANY NOT PROPOSING TO FINANCE ITS GRID MODERNIZATION INVESTMENT THROUGH BASE RATES?

A. The GMR will permit the Company to implement AMI and other grid modernization projects, following Commission approval, more quickly than would be the case if they were to be financed through base rates alone, thereby benefiting all distribution customers. The Company's base rate proposal will not allow the Company to make the investment required to deploy AMI, for example, over the proposed four-year period. Second, the GMR has the ability to lengthen the time between base rate cases, smoothing out rate increases to smaller incremental annual increases rather than larger increases every two to three years. Third, the replacement of AMR meters with AMI meters, although not driven principally by safety concerns, is more similar than dissimilar to the accelerated main replacement programs approved by the Commission even before Chapter 278 was amended to expressly recognize such ratemaking treatment. Finally, as with any rider of this sort, the GMR will ensure that customers pay no more than, nor less than, the amount required to implement AMI and other grid modernization projects. These are all benefits associated with separately tracking distribution modernization and reliability projects.

Q. IN JOINT INTERVENORS WITNESS OWEN'S DIRECT TESTIMONY AT PAGE 55, LINES 9-11, HE STATES, "BEYOND THE NORMAL LAG, IF THE COMPANY'S PREFERRED COST RECOVERY MECHANISM IS APPROVED IN THIS CASE, CUSTOMERS WILL BE PAYING FOR THESE METERS WITHOUT THE CLOSE SCRUTINY GIVEN IN RATE CASES ON INCREASED INTERVALS." DO YOU AGREE?

A. No, I do not agree. Perhaps Mr. Owen misunderstood my Direct Testimony at pages 9-12, where I explained that the GMR would be trued-up in annual filings. The Commission will have an opportunity every 12 months to review all costs flowing through the GMR, including any savings identified once AMI has been fully implemented. Thus, contrary to Mr. Owen's argument, the Commission will have a more frequent opportunity to fully review AMI metering costs through the GMR than would be the case if those costs were included in base rates.

Mr. Owen's contention (at p. 55) that customers will have to bear increased costs of operating two meter reading systems in parallel before realizing any benefits from AMI also is not true. As detailed in the Direct Testimony of Company Witnesses Blankenship (at p. 11) and Wiseman (at p. 11), numerous benefits of AMI accrue to customers immediately upon a meter's installation, including access to interval data through the Green Button on the Company's website or through a Customer Engagement Platform to monitor their usage more closely, high-bill alerts, remote connection or reconnection of the meter, Flex Pay, and outage notifications.

What is true is that during the implementation period lasting four years, the Company will have to operate two metering systems at the same time. A project of this size, replacing approximately 172,000 AMR meters with AMI meters as well as the associated infrastructure, simply cannot be done overnight. The four-year implementation period was chosen, in part, so that costs would be spread over a reasonable period of time limiting annual increases in the GMR. Other considerations in selecting the implementation period were availability of labor, materials and scheduling.

Q. MR. OWEN MAKES SEVERAL RECOMMENDATIONS AT PAGES 62-63 OF HIS TESTIMONY ASSOCIATED WITH THE ELIMINATION OF CHARGES IN CONNECTION WITH SERVICES THAT CAN BE PERFORMED REMOTELY FOLLOWING THE INSTALLATION OF AN AMI METER. DOES THE COMPANY AGREE?

A. Yes. The installation of AMI meters will permit the Company to perform remotely many of the tasks now requiring a service trip. With the elimination of the service trip, the need for a nonrecurring trip charge also is eliminated. The Company thus proposed at page 13 of Company Witness Blankenship's Direct Testimony to eliminate the connection and reconnection charges on Sheet 2-11 of the Company's tariffs where the work can be performed remotely. These would include those special charges shown at Paragraph 19 (A) 1-5 of the Company's tariff. To be clear, there are certain limited services that will still require a service trip even with AMI metering. These include, for example, those instances where the Company is required to disconnect and reconnect service at the pole because the customer is tampering with a meter or otherwise obtaining service fraudulently. In addition, trips made to a customer's premise for credit and collection purposes also would be required even with AMI meters and thus the customer should be responsible for a portion of their cost. The Company also will be required to make a service trip to test (but not re-read) a meter. A service charge remains appropriate in these limited instances. Mr. Owen also seemingly proposes to eliminate permanently other non-specified nonrecurring charges that can be performed remotely with AMI. Kentucky Power is not aware of any such tariffed charges, but it agrees in principle that where a service can be provided remotely and with no incremental cost with AMI technology, there is no need for a nonrecurring charge.

Q. WILL THE COMPANY ACCOUNT FOR ANY SAVINGS, TO THE EXTENT THEY CAN BE QUANTIFIED, IN THE GMR AS MR. OWEN ADVOCATES?

A. Yes. In the Company's response to AG/KIUC 1-89, a number of cost reductions were identified with respect to transitioning to AMI meters, including reductions in Meter Revenue Operations' spending; reductions in credit and collections and bad debt expenses on past due accounts; and remote connect and disconnect of meters as well as open and close account orders. To the extent that these savings can be quantified, the Company will credit the savings in the annual true-up of the GMR. During the test year, there was approximately $188,000 for meter reconnect charges. The full amount of such charges will be credited in the GMR true-up calculation once full implementation of AMI meters has been completed.

Q. WHY IS THE COMPANY NOT PROPOSING TO FLOW THESE SAVINGS BACK TO CUSTOMERS PRIOR TO FULL DEPLOYMENT OF THE AMI METERS?

A. The Company's AMI implementation plan covers four years. The Company will not begin realizing these savings until all AMR meters have been replaced with AMI meters, because the Company will still incur costs associated with trips made to locations to reconnect or perform a check reading.

Q. BEGINNING AT PAGE 60, LINES 6-10 OF HIS DIRECT TESTIMONY, AG/KIUC WITNESS KOLLEN STATES "…THE COMPANY WILL ACHIEVE DEPRECIATION EXPENSE SAVINGS WHEN IT RETIRES THE AMR METERS AND RELATED INFRASTRUCTURE AND IS REQUIRED TO DISCONTINUE DEPRECIATION EXPENSE ON THOSE RETIRED ASSETS PURSUANT TO GENERALLY ACCEPTED ACCOUNTING PRINCIPLES ("GAAP") AND THE FERC UNIFORM SYSTEM OF ACCOUNTS ("USOA")." DO YOU AGREE WITH MR. KOLLEN?

A. No. In his statement, Mr. Kollen is only focusing on a specific retirement and fails to acknowledge any plant additions that will occur during this same time period. Mr. Kollen is correct that depreciation expense ceases to be recorded on an asset when a retirement is recorded in accordance with GAAP and the FERC USOA. However, Mr. Kollen fails to recognize that depreciation expense begins to be accrue when an asset is placed in service in accordance with GAAP and the FERC USOA.

Q. DOES THE COMPANY ACHIEVE DEPRECIATION EXPENSE SAVINGS WITH THE FUTURE RETIREMENT OF ITS AMR METERS OR ANY OF THE RELATED ASSETS THAT WILL BE RETIRED AFTER THE TEST YEAR PERIOD?

A. No. None of the additions nor the retirements that occur after the test year and after base rates are reset in this proceeding are included in the Company's level of depreciation. Instead, they will be addressed until the next base rate proceeding. The level of depreciation expense that is established in this proceeding will determine a reasonable amount of depreciation expense that will be incurred as a part of the

Company's day-to-day operations. Therefore, it is incorrect for Mr. Kollen to state that the Company will achieve depreciation expense savings as a result of the Company's AMR meters being retired without accounting for the offsetting increase in depreciation expense in connection with placing AMI meters in service.[1]

Q. MR. KOLLEN FURTHER STATES THE COMPANY WILL NO LONGER INCUR AD VALOREM TAX EXPENSE ON THE RETIRED AMR METERS AND RELATED INFRASTRUCTURE. HOW DO YOU RESPOND?

A. Mr. Kollen is unaware of the taxability of the to-be-retired assets. Kentucky assesses ad valorem tax on the net book value ("NBV") of all equipment on the Company's books. Once retired, the AMR equipment moves from FERC Account 101 to 108 until it is addressed in the next base rate case. Therefore, the NBV and hence, taxability of the AMR meters will not change due to retirement. With their value still included in the overall NBV, the Company will continue to incur ad valorem tax expense on the retired AMR meters and will incur additional tax expense on the new AMI equipment. In the next base rate case, the Company will propose a time frame over which to recover the undepreciated NBV of the AMR meters. The Company included the full ad valorem taxes on the new AMI meters and related infrastructure, and did not show a reduction based on the retired assets, because they remain taxable.

[1] Company's response to AG/KIUC 1-63.

V. REVENUE ADJUSTMENTS

Q. MR. KOLLEN RECOMMENDS AT PAGES 37-38 OF HIS TESTIMONY A REDUCTION IN EXPENSE TO THE BASE REVENUE REQUIREMENT OF $0.048 MILLION RELATED TO EEI DUES. DO YOU AGREE WITH THIS RECOMMENDATION?

A. No, I do not. Figure 2 below shows that the portion of EEI dues allocated to Kentucky Power related to legislative activities were properly excluded from the cost of service in this case.

Figure 2

EEI Invoice Line Item	AEP Legislation %	AEP Legislation Amount	KPCo Allocation	KPCo Legislative Allocation (3.9%)
$ 2,397,228	13%	$ 311,639.64	$ 92,986.75	$ 12,088.28
239,723	26%	$ 62,327.98	$ 9,298.68	$ 2,417.66
15,000			$ 581.84	
50,000			$ 1,939.46	$ 1,939.46
$ 2,701,951			**$ 104,806.74**	

KPCo Allocation	3.88%

Journal ID	Account	Invoice	Amount	Included or Excluded from Cost of Service?
APACC14031	4261000	DUES202005	$ 1,939.46	Excluded
APACC14031	4264000	DUES202005	$ 14,505.94	Excluded
APACC14031	9302000	DUES202005	$ 88,361.34	Included
Total			**$ 104,806.74**	

Adopting Mr. Kollen's recommended adjustment would result in the inappropriate exclusion of twice the amount of EEI dues paid by the Company during the test year.

VI. OTHER ISSUES

Q. MR. KOLLEN TESTIFIES AT PAGE 43 RECOMMENDING THE COMMISSION CHOOSE AN ARBITRARY COST OF DEBT FOR A FUTURE DEBT ISSUANCE AND TO CREATE A REGULATORY ASSET OR LIABILITY TO BE RECONCILED IN THE NEXT BASE RATE CASE. DO YOU AGREE WITH THIS PROPOSAL?

A. No, I do not agree. Mr. Kollen is asking the Commission to choose an arbitrary value for the cost of long-term debt to compare over/under against the Company's actual cost of existing debt, essentially the current debt issuance and the future debt issuance. This is inappropriate and against established cost-of-service ratemaking principles. Although test year values may be adjusted for post-test year changes, there is nothing known and measurable about a hypothetical refinancing that may take place 15 months after the end of test year. Even if some portion of the long-term debt will be refinanced with long-term debt, there is nothing known nor measureable about the amount of the long-term debt to be issued nor the applicable interest rate. Mr. Kollen cannot possibly know, beyond a guess, what the cost of a new long-term debt issuance will be in June 2021. Statements such as, "The cost of new debt ***likely*** will be less than 4.0% and ***could be*** less than 3.0% depending on the tenor (term) of the new debt that is issued and the market pricing available for the tenor selected."[2] [emphasis added] do not instill faith in Mr. Kollen's ability to predict the future. The Company's known and measurable cost of debt is included in this case and should be used to determine the

[2] Kollen Direct Testimony at page 42.

Company's cap structure and overall revenue requirement. Kollen's recommendation should be rejected by the Commission.

Q. MR. OWEN TESTIFIES AT PAGES 39-53 REGARDING THE CURRENT BUDGET FOR DEMAND-SIDE MANAGEMENT ("DSM") PROGRAMS AS WELL AS NEW PROGRAMS. HOW DO YOU RESPOND?

A. As Mr. Owen correctly points out that in Case No. 2017-00097 the Commission ordered Kentucky Power to eliminate all DSM programs except for the Targeted Energy Efficiency ("TEE") program. The Commission cited Kentucky Power's lack of near-term or immediate need for capacity or energy as its basis for eliminating all but one DSM program.[3] The Company continues to be capacity long for the immediate future until the Rockport UPA expires. The order further states:

> In the event Kentucky Power seeks in the future to expand its DSM offerings, any future application should be supported by detailed and robust cost-benefit analyses *along with information concerning the company's capacity position and the need for the proposed DSM programs*. Future DSM programs should include robust targeted programs that assist participation by low-income customers and designed to be capable of tracking when program funds are expected to be fully subscribed, when program funds are actually fully subscribed, and when a customer participating in a DSM program is contacted and notified as to the availability of program funds.[4]

Mr. Owen's suggestion at best is premature.

The Commission has made clear that any proposed DSM programs, including annual budgets, would need to be fully evaluated and filed for Commission review in a separate proceeding.[5] Kentucky Power's TEE program and Tariff D.S.M.C., along

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[3] Order dated January 18, 2018, at page 13 in Case No. 2017-00097.

[4] Order dated January 18, 2018, at page 15 in Case No. 2017-00097 (emphasis supplied).

[5] *Id*.

with any new programs, should be addressed in separate proceeding. That is the appropriate place to consider proposals like Mr. Owen's.

Finally, all revenues and expenses from riders, including Tariff D.S.M.C. (Demand-Side Management Adjustment Clause), are removed from the cost of service as part of preparing a base rate case. In essence, DSM programs, their costs and benefits, market-potential studies, and proposed program details are not part of this base rate case proceeding.

Q. ON UNNUMBERED PAGE 7 OF HIS TESTIMONY, JOINT INTERVENORS WITNESS BILLS IS CRITICAL OF THE COMPANY'S REQUIREMENT THAT COMMERCIAL CUSTOMERS WHO WISH TO TAKE NET METERING SERVICE MUST, IN SOME CASES, UPGRADE FROM DELTA THREE-PHASE SERVICE TO WYE THREE-PHASE SERVICE AT THE CUSTOMER'S COST. HOW DO YOU RESPOND?

A. Basically, this is a safety issue. The Company's Tariff N.M.S., as well as the Company's proposed Tariff N.M.S. II, under Level 1 and Level 2 Definitions, Level 1, Condition 5, states: "If the generating facility is to be connected to three-phase, four wire primary Company distribution lines, the generator shall appear to the primary Company distribution line as an effectively grounded source." It is my understanding that any service connected to a 120/240 four-wire delta secondary transformer bank such as Mr. Bills proposes does not satisfy that requirement. This not only is contrary to the tariff provision, but presents a safety issue because transformers installed in a delta configuration increase the chances for high voltage situations to occur on the line, which can damage distribution equipment and imperil line personnel. The Company makes every effort to find an alternative for customers desiring to connect to the system that meets the requirements for Level 1 consideration. However, the cost of any such upgrade is appropriately borne by the customer. At present, no other AEP operating company allows interconnection of any customer-generator facilities to a 120/240 delta secondary service.

Q. WOULD THIS ISSUE BE MORE APPROPRIATELY CONSIDERED IN CASE NO. 2020-00302, INVESTIGATION OF INTERCONNECTION AND NET METERING GUIDELINES?

A. Yes. Case No. 2020-00302 is the more appropriate place to consider this issue, which seemingly would apply to all electric utilities' net metering interconnections.

VII. CONCLUSION

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes, it does.

VERIFICATION

The undersigned, Brian K. West, being duly sworn, deposes and says he is Director Regulatory Services for Kentucky Power Company that he has personal knowledge of the matters set forth in the forgoing testimony and the information contained therein is true and correct to the best of his information, knowledge and belief after reasonable inquiry.

Brian K. West

State of Indiana)
) ss Case No. 2020-00174
County of Allen)

Subscribed and sworn to before me, a Notary Public, in and for said County and State, Brian K. West this 5th day of November, 2020.

Regiana M. Sistevaris

Digitally signed by Regiana M. Sistevaris
Date: 2020.11.05 07:13:55 -05'00'

Regiana M. Sistevaris, Notary Public

My Commission Expires: January 7, 2023

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

Electronic Application Of Kentucky Power Company For (1) A General Adjustment Of Its Rates For Electric Service; (2) Approval Of Tariffs And Riders; (3) Approval Of Accounting Practices To Establish Regulatory Assets And Liabilities; (4) Approval of A Certificate of Public Convenience And Necessity; And (5) All Other Required Approvals And Relief	)))))))	Case No. 2020-00174

REBUTTAL TESTIMONY OF

HEATHER M. WHITNEY

ON BEHALF OF KENTUCKY POWER COMPANY

REBUTTAL TESTIMONY OF
HEATHER M. WHITNEY ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

CASE NO. 2020-00174

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EXHIBITS

EXHIBIT	DESCRIPTION
EXHIBIT HMW-R1	June 2017 Pension Plan Cash Contribution
EXHIBIT HMW-R2	September 2020 Pension Plan Cash Contribution
EXHIBIT HMW-R3	Rollforward of Prepaid Pension and OPEB Asset Balances and Computation of Related Cost of Service Reduction

REBUTTAL TESTIMONY OF
HEATHER M. WHITNEY ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS AND PRESENT POSITION.

A. My name is Heather M. Whitney. My business address is 1 Riverside Plaza, Columbus, Ohio 43215. I am employed by the American Electric Power Service Corporation ("AEPSC") as a Director in Regulatory Accounting Services. AEPSC is a wholly-owned subsidiary of American Electric Power Company, Inc. ("AEP"). AEP is the parent company of Kentucky Power Company ("Kentucky Power" or the "Company").

Q. ARE YOU THE SAME HEATHER M. WHITNEY WHO OFFERED DIRECT TESTIMONY IN THIS PROCEEDING?

A. Yes.

II. PURPOSE OF REBUTTAL TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. The purpose of my testimony is to respond to the proposed adjustment presented in the prepared Direct Testimony of Attorney General of the Commonwealth of Kentucky and Kentucky Industrial Utility Customers, Inc. ("AG/KIUC") Witness Lane Kollen to remove prepaid pension and prepaid other postretirement employee benefit ("OPEB") assets from rate base.

I support the inclusion of the prepaid pension and prepaid OPEB assets in rate base.[1] These are cash assets financed by the Company and benefit customers through substantially reduced costs. The Company's accounting is proper under generally accepted accounting principles ("GAAP"), and has received a clean opinion from two separate external auditors. Moreover, if the Commission removes the pension and OPEB assets from rate base and requires the "return on" component of the revenue requirement to be computed using rate base instead of capitalization, then test year cost of service expense must be increased to remove the $3.7 million benefit (lower expense) resulting from these additional contributions.

Q. ARE YOU SPONSORING ANY REBUTTAL EXHIBITS OR SCHEDULES?

A. Yes, I am sponsoring the following exhibits:

- Exhibit HMW-R1 – June 2017 Pension Plan Cash Contribution
- Exhibit HMW-R2 – September 2020 Pension Plan Cash Contribution
- Exhibit HMW-R3 – Rollforward of Prepaid Pension and OPEB Asset Balances and Computation of Related Cost of Service Reduction

[1] The Prepaid Pension balance as of February 28, 2017 was included in Total Rate Base authorized in Case No. 2017-00179. Prepaid Pension and OPEB balances as of February 28, 2017 were reflected in Total Capitalization authorized in Case No. 2017-00179.

III. PREPAID PENSION AND OPEB ASSETS IN RATE BASE

Q. DOES AG/KIUC WITNESS KOLLEN TAKE EXCEPTION TO THE COMPANY'S INCLUSION OF PREPAID PENSION AND OPEB ASSETS IN RATE BASE?

A. Yes. AG/KIUC Witness Kollen recommends that the Commission reject the Company's request to include the prepaid pension and OPEB assets in rate base. Mr. Kollen states that the effects of his recommendation, if approved, would be to reduce rate base by $44.206 million ($44.879 million total Company) for the prepaid pension asset and $19.872 million ($20.175 million total Company) for the prepaid OPEB asset. According to Mr. Kollen, the effect of reducing rate base for these amounts is a reduction of $5.204 million in the base revenue requirement, if the "return on" component of the revenue requirement is computed using rate base instead of capitalization. Company Witness Vaughan's rebuttal testimony supports the Company's continued use of capitalization to compute the "return on" component of the revenue requirement.

Q. PLEASE SUMMARIZE THE REASONS GIVEN BY AG/KIUC WITNESS KOLLEN IN SUPPORT OF HIS RECOMMENDATION TO EXCLUDE THE PREPAID PENSION AND OPEB ASSETS FROM RATE BASE.

A. Mr. Kollen provides the following arguments and assertions in support of his position to exclude the prepaid pension and OPEB assets from rate base:

1. "…the prepaid pension asset and prepaid OPEB asset are not cash assets and should not be included in rate base";[2]

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[2] Direct Testimony of Lane Kollen at 13.

2. "…there is no prepaid pension asset and there is no prepaid OPEB asset unless you ignore the negative amounts in accounts 1650014 and 1650037, which is what the Company did in its calculation of rate base";[3]

3. "…there is no financing requirement associated with those accounts [accounts 1650010, 1650035, 1650014, and 1650037] and no further inquiry is required";[4] and

4. "…the Company's accounting reflected in these four accounts [accounts 1650010, 1650035, 1650014, and 1650037] is not required, defined, or described by GAAP or the FERC USOA. Rather, AEP itself has uniquely defined these accounts for use by its operating utilities within its accounting system for recordkeeping purposes and, as is apparent in multiple rate proceedings in multiple jurisdictions, to assist the operating companies in their attempts to increase rate base by including only the positive amounts in accounts 1650010 and 1650035 in rate base."[5]

Q. DO YOU AGREE WITH AG/KIUC WITNESS KOLLEN'S RECOMMENDATION TO EXCLUDE THE PREPAID PENSION AND OPEB ASSETS FROM RATE BASE?

A. No, I disagree with the AG/KIUC's recommendation and each of the reasons given in support of AG/KIUC Witness Kollen's position. I will address each of the statements referenced above as well as others from AG/KIUC Witness Kollen's testimony and demonstrate that these arguments and assertions are erroneous and/or baseless.

Q. WHAT SUPPORT DOES AG/KIUC WITNESS KOLLEN PROVIDE FOR HIS CLAIM THAT "…THE PREPAID PENSION ASSET AND PREPAID OPEB ASSET ARE NOT CASH ASSETS…"?

A. Mr. Kollen's support for this assertion is not clear to me, but seems to be based on his incorrect interpretation of amounts recorded in the Company's general ledger, despite

[3] *Id*. at 18.

[4] *Id.* at 21.

[5] *Id.* at 19.

the Company's response to AG/KIUC 2-17. He erroneously deduces that, "The amounts in the four account 165 accounts net to $0, so there is no financing requirement associated with those accounts…," leaving only balances in accounts he refers to as regulatory assets which are, "merely accounting entries that have not been financed."[6] Mr. Kollen's position hinges on a failure to acknowledge that the Company has, in fact, made cash contributions to the pension and OPEB plans in excess of cost, as well as a misinterpretation of a non-cash reclass made for financial reporting purposes under Financial Accounting Standards Board ("FASB") Accounting Standards Codification ("ASC") 715, Compensation - Retirement Benefits ("Non-Cash ASC 715 Reclass"), supplied in the Company's response to AG/KIUC 2-17.

Q. CAN YOU PLEASE EXPLAIN THE COMPANY'S RESPONSE TO AG/KIUC 2-17 AND PROPERLY DISTINGUISH PENSION AND OPEB CASH PREPAYMENT BALANCES FROM THE NON-CASH ASC 715 RECLASS RECORDED USING A BALANCED, NET $0, ENTRY?

A. Yes. Below, I have aligned the table provided in response to subpart a. of AG/KIUC 2-17 and presented in Mr. Kollen's testimony[7] with the written response to subparts c. and d. of AG/KIUC 2-17. Lines 1 and 9 contain the cash prepayment balances. Lines 2 – 7 contain the Non-Cash ASC 715 Reclasses, which balance to a net $0 amount as shown in Line 8 and expected under accrual, double-entry accounting[8].

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[6] *Id.* at 21.

[7] Direct Testimony of Lane Kollen at 20.

[8] FASB Statement of Financial Accounting Concepts No. 6, Paragraphs 20 and 21, ***Interrelation of Elements – Articulation***, supports the expectation of a balanced entry when applying accrual, double-entry accounting. Specifically, Paragraph 21 provides, "*…an increase (decrease) in an asset cannot occur without a corresponding decrease (increase) in another asset or a corresponding increase (decrease) in a liability or equity (net assets).*"

AG-KIUC 2-17, Subpart a.
Kentucky Power Company
Pension and OPEB Balances as of December 31, 2019

Line No.	Account	Description	Pension	OPEB	Subtotal Tie Out	Cross Reference: AG-KIUC 2-17, Subparts c. and d.	Other References
1	1650010/ 1650035	Prepayment - Contributions	$45,500,106	$19,143,276	A	"The balances in Account 1650010 and 1650035 reflect the Companies' **cumulative <u>cash</u> contributions** in excess of cumulative pension and OPEB cost."	Exhibit HMW-R1 Exhibit HMW-R2 Exhibit HMW-R3
2	1650014/ 1650037	ASC 715 Prepayment Reclass	(45,500,106)	(19,143,276)	B, C	"There are also **<u>non-cash</u> ASC 715 accrual adjustment balances** recorded in Accounts 1290000, 1290001, 1290002, 1290003, 1650014, 1650037, 1823165, 1823166, 2190006, 2190007, 1900010, 1900011, 2283006 and 2283016 that result from entries required by ASC 715 **to separate the calculated prepayment** into two separate components. The **first component is the funded status** and **second component is other comprehensive income (or a regulatory asset)** for gains and losses that have not yet been recognized as components of net periodic benefit cost."	Total Non-Cash ASC 715 Reclass
3	1290000/ 1290001	ASC 715 Trust Funded Positions (Assets)	-	23,421,499	B		Reclass Component 1: Funded status
4	2283016/ 2283006	ASC 715 Trust Funded Position (Liabilities)	(1,611,500)	-	B		
5	1823165/ 1823166	ASC 715 - Regulatory Asset	45,940,166	(2,107,133)	B		Reclass Component 2: Other comprehensive income/ regulatory asset
6	1900010/ 1900011	ASC 715 - ADFIT Asset	246,002	(455,929)	B		
7	2190006/ 2190007	ASC – 715 Other Comprehensive Income	925,438	(1,715,161)	B		
8		**Total ASC 715 Entries**	-	-	= ∑ B's	"...The prepaid assets related to pension and OPEB are recorded on the Company's books under FASB ASC 715, Compensation - Retirement Benefits." "...the ASC 715 entries zero out [Sum of B's] leaving the **<u>cash prepayment [A]</u>** that is the Company's cumulative contributions in excess of cumulative pension and OPEB cost, which is included in the Company's calculation of rate base in this proceeding. The **<u>non-cash ASC 715 accounting entries [Sum of B's]</u>** are made for financial reporting purposes and **<u>do not impact the cost of service</u>**."	
9		**Total Prepayment Contributions**	**45,500,106**	**19,143,276**	= A		
10		Total Excluding 165 Accounts	$ 45,500,106	$ 19,143,276	= ∑B's - C	-	

Line 10 in the table above reflects the position of AG/KIUC Witness Kollen, which is based on a misinterpretation of the Non-Cash ASC 715 Reclass, since it results in an unbalanced entry. Mr. Kollen's view is that the Non-Cash ASC 715 Reclass on Line 2 should be isolated and evaluated separately from the remaining elements of the Non-Cash ASC 715 Reclass entry shown in Lines 3 – 7, since the non-cash amounts in Line 2 are recorded to the same FERC account as the cash prepayments shown in Line 1, FERC Account 165. As can be clearly seen, Mr. Kollen's view is erroneous and baseless under the basic accrual accounting concept of balanced journal entries; it is misleading in that Mr. Kollen's departure from a basic accrual accounting concept veils the Company's actual cash prepayment (Line 1) with one unbalanced element of a non-cash reclass entry (Line 2) and then characterize the remaining, unbalanced elements of the non-cash reclass entry (Lines 3 - 7) as ineligible for inclusion in rate base since the non-cash amounts are not financed.

Q. DO YOU HAVE EVIDENCE TO SHOW THAT THE COMPANY'S PREPAID PENSION ASSET RECORDED IN ACCOUNT 1650010 IS, IN FACT, A CASH ASSET?

A. Yes. Page 1 of Exhibit HMW-R1 and Exhibit HMW-R2 shows the payments made by AEP to the Bank of New York in June 2017 and September 2020, respectively, on behalf of the AEP subsidiary companies, including Kentucky Power Company, for the pension plan contributions made since the Company's last base case proceeding in Case No. 2017-00179. Page 2 of Exhibit HMW-R1 and Exhibit HMW-R2 shows Kentucky Power Company's portion of this cash payment allocated to the Kentucky Power Company Distribution, Transmission and Generation functional business units. Page 2 of Exhibit HMW-R1 and Exhibit HMW-R2 also shows that the entry at the time of the pension contribution recorded on Kentucky Power Company's books was a debit to Account 1650010, Prepaid Pension Benefits, and a credit to Account 2340001, Accounts Payable Assoc Co - InterUnit G/L. Kentucky Power Company reimbursed AEP for the pension plan contribution through the AEP Money Pool. Therefore, the Company's prepaid pension and OPEB assets are "cash assets" because they were established based on cash transactions.

Q. WAS THE PROCESS FOR THE COMPANY'S CASH CONTRIBUTIONS TO THE PENSION PLAN PRIOR TO THE TEST YEAR END DATE IN THE COMPANY'S LAST BASE CASE PROCEEDING (CASE NO. 2017-00179) THE SAME AS YOU DESCRIBED ABOVE FOR THE 2017 AND 2020 PENSION PLAN CONTRIBUTIONS?

A. Yes.

Q. HAS THE COMPANY MADE ANY CASH CONTRIBUTIONS TO THE OPEB PLAN SINCE THE TEST YEAR END DATE IN THE COMPANY'S LAST BASE CASE PROCEEDING?

A. No. The prepaid OPEB asset was established on the Company's books in March 2014. Prior to 2014, the Company's OPEB funding policy was to contribute an amount to the OPEB trust fund equal to the other postretirement benefit cost. The Company stopped making OPEB contributions after 2012 when the cost became negative due to changes made to the retiree medical coverage. These changes included the capping of contributions to retiree medical costs thus reducing the Company's future exposure to medical cost inflation. Also, effective for employees hired after December 2013, retiree medical coverage will not be provided.

Q. WAS THE PROCESS FOR THE COMPANY'S CASH CONTRIBUTIONS TO THE OPEB PLAN PRIOR TO 2012 (WHEN THE COST BECAME NEGATIVE DUE TO CHANGES MADE TO RETIREE MEDICAL COVERAGE) THE SAME AS YOU DESCRIBED ABOVE FOR THE 2017 AND 2020 PENSION PLAN CONTRIBUTIONS?

A. Yes.

Q. DOES AG/KIUC WITNESS KOLLEN AGREE THAT CASH ASSETS SHOULD EARN A RETURN THROUGH INCLUSION IN RATE BASE?

A. Yes, it would appear so. Mr. Kollen states that, "If the former [accounts are assets that the Company financed], then they should be included in rate base." He does not clearly convey his definition of "financed"; however, he does indicate that outlay of cash provides evidence of financing and supports inclusion in rate base.[9] As demonstrated in Exhibit HMW-R1 and Exhibit HMW-R2, and as discussed above, the Company's prepaid pension and OPEB assets are cash assets and as such, are reflected Kentucky Power Company's capitalization and are appropriately included in rate base in Kentucky Power Company's cost of service studies.

Q. DO THE COMPANY'S CASH PREPAID PENSION AND OPEB ASSETS PRODUCE A NET BENEFIT TO CUSTOMERS?

A. Yes. Exhibit HMW-R3 rolls the prepaid pension and OPEB asset account balances forward from the Company's last base case proceeding in order to demonstrate that period-end prepaid account balances (Column C) represent cumulative cash contributions (contributions since last base case reflected in Column A) in excess of cumulative pension and OPEB cost (cost since last base case reflected in Column B). In addition, Exhibit HMW-R3 shows the cumulative prepaid pension and OPEB assets have reduced Total Company pension and OPEB cost Kentucky Power Company would otherwise have incurred and recorded on its books by approximately $3.8

[9] Direct Testimony of Lane Kollen at 13. There, Mr. Kollen testifies that, "…the prepaid pension asset and prepaid OPEB asset are not cash assets and should not be included in rate base." Therefore, inversely, cash assets should be included in rate base.

million annually since the Company’s last base case proceeding (Exhibit HMW-R3, Line 23). In other words, had the cash contributions not been made to the pension and OPEB plans, the Company’s total amount of pension and OPEB cost would have increased by approximately $3.8 million annually. For the Company’s test year ended March 31, 2020, approximately $3.7 million in cost savings were included as a reduction in the Company’s cost of service (Exhibit HMW-R3, Line 19).

Q. ARE WITNESS KOLLEN’S CLAIMS THAT THE COMPANY IGNORED “…THE NEGATIVE AMOUNTS IN ACCOUNTS 1650014 AND 1650037…IN ITS CALCULATION OF RATE BASE.” AND , “THERE IS NO FINANCING REQUIREMENT ASSOCIATED WITH THOSE ACCOUNTS [ACCOUNTS 1650010, 1650035, 1650014, and 1650037]…”ACCURATE?

A. No, as I previously explained, this assertion is both erroneous and baseless under the basic accrual accounting concept of balanced journal entries. In addition, as further explained below, the inclusion or exclusion of the negative amounts in accounts 1640014 and 1650037 does not change the amounts or character of the prepaid pension and OPEB cash assets that should be included in rate base when all related non-cash accounts are considered.

Q. CAN YOU EXPLAIN THE PURPOSE OF THE NON-CASH ASC 715 ACCRUAL ADJUSTMENT BALANCE SHEET ACCOUNTS, INCLUDING THE NEGATIVE AMOUNTS IN ACCOUNTS 1650014 AND 1650037?

A. Yes. The prepaid assets related to pension and OPEB are recorded on the Company's books under FASB ASC 715, Compensation - Retirement Benefits. The Company has recorded the cash prepaid pension balance in Account 1650010 and cash prepaid OPEB balance in Account 1650035 and included such balances in rate base. The balances in Account 1650010 and 1650035 reflect the Company's cumulative cash contributions in excess of cumulative pension and OPEB cost. There are also non-cash ASC 715 accrual adjustment balances recorded in Accounts 1290000, 1290001, 1290002, 1290003, 1650014, 1650037, 1823165, 1823166, 1900010, 1900011, 2190006, 2190007, 2283006, and 2283016 that result from the Non-Cash ASC 715 Reclass entries required by ASC 715 to separate the calculated prepayment into two separate components – the funded status and accumulated other comprehensive income (or a regulatory asset) for gains and losses that have not yet been recognized as components of net periodic benefit cost.

To recognize the funded positions, the Company records a series of balance sheet entries for the components of Kentucky Power Company's pension and OPEB plan prepayments. Specifically, for periods in which Kentucky Power Company's pension and OPEB plans are in an overfunded position, the Company records an asset balance to Account 129 for the overfunded amount, and for periods in which Kentucky Power Company's pension and OPEB plans are under-funded, the Company records a liability balance to Account 228.3 for the net under-funded amount.

The Company records, as a component of accumulated other comprehensive income, Account 219, the changes in the funded status that arise during the year that are not recognized as a component of net periodic benefit cost, with the tax effect recorded to Account 190, Accumulated deferred income taxes. A regulatory asset is recorded to Account 182.3 instead of accumulated other comprehensive income for qualifying benefit costs of regulated operations that are deferred for future recovery.

The total of the funded status recorded to Account 129 or 228.3, and the cumulative funded status adjustment recorded to Accounts 219 and Account 190, or Account 182.3 as applicable, will equal the corresponding pension and OPEB plan prepayments recorded to Account 165. In other words, these entries simply move amounts between various balance sheet accounts to facilitate financial reporting in accordance with ASC 715, but do not alter the original transactions of recording cash contributions to the pension and OPEB trust as a prepayment and recording expenses as the prepayment is used.

Q. WITNESS KOLLEN CRITICIZES THE COMPANY FOR IGNORING THE NEGATIVE AMOUNTS IN ACCOUNTS 1650014 AND 1650037 FOR RATE BASE PURPOSES. DOES MR. KOLLEN IGNORE THE OTHER NON-CASH BALANCE SHEET ACCOUNTS IN HIS TESTIMONY RELATED TO PENSIONS AND OPEB?

A. Yes. The Company's response to AG/KIUC 2-17, which is attached to the testimony of AG/KIUC Witness Kollen as Exhibit __ (LK-9), provided the complete list of Non-Cash ASC 715 Reclass accrual adjustment accounts including Accounts 1650014 and 1650037 as well as Accounts 1290000, 1290001, 1290002, 1290003, 1823165, 1823166, 1900010, 1900011 2190006, 2190007, 2283006, and 2283016 that are excluded from rate base and have no effect on ratemaking because they zero out thus leaving, for ratemaking, the proper amount of prepayment financed by the Company.

Q. WOULD IT BE APPROPRIATE TO INCLUDE THE NEGATIVE AMOUNTS IN ACCOUNTS 1650014 AND 1650037 IN RATE BASE WITHOUT INCLUDING THE OTHER NON-CASH ASC 715 RECLASS BALANCE SHEET ACCOUNTS?

A. No, it would be very inappropriate to include only part of the Non-Cash ASC 715 Reclass pension and OPEB balance sheet accounts in rate base as suggested by AG/KIUC Witness Kollen. As previously discussed, this would be an erroneous departure from the basic accrual accounting concept of balanced journal entries and would be improper ratemaking by ignoring an asset financed by the Company.

Q. WOULD THE RESULT CHANGE IF ALL OF THE NON-CASH ASC 715 RECLASS BALANCE SHEET ACCOUNTS WERE INCLUDED IN RATE BASE VERSUS EXCLUDING ALL OF THESE ACCOUNTS AS THE COMPANY HAS DONE?

A. No, the impact on rate base would be exactly the same as that recommended by the Company in this proceeding. Below are the Kentucky Power Company balances at March 31, 2020 associated with the pension and OPEB prepayments:

Kentucky Power Company
Pension and OPEB Balances as of March 31, 2020

Line No.	Account	Description	Pension	OPEB	Subtotal Tie Out
1	1650010/ 1650035	Prepayment - Contributions	$44,879,334	$20,174,958	A
2	1650014/ 1650037	ASC 715 Prepayment Reclass	(44,879,334)	(20,174,958)	B
3	1290000/ 1290001/ 1290002/ 1290003	ASC 715 Trust Funded Positions (Assets)	-	23,899,853	B
4	2283016/ 2283006	ASC 715 Trust Funded Position (Liabilities)	(1,409,642)	-	B
5	1823165/ 1823166	ASC 715 - Regulatory Asset	45,132,948	(1,602,940)	B
6	1900010/ 1900011	ASC 715 - ADFIT Asset	242,766	(445,610)	B
7	2190006/ 2190007	ASC – 715 Other Comprehensive Income	913,262	(1,676,344)	B
8		Total ASC 715 Entries	-	-	= ∑ B's
9		Total Prepayment Contributions	44,879,334	20,174,958	= A
10		Total	$ 44,879,334	$ 20,174,958	= A + ∑B's

As can be seen above, the Non-Cash ASC 715 Reclass entries zero out (Line 8) leaving the cash prepayment that is the Company's cumulative contributions in excess of cumulative pension and OPEB cost (Line 9). For ratemaking, the Company has traditionally excluded the Non-Cash ASC 715 Reclass accounting entries because it is simply geography on the balance sheet for financial reporting purposes. However, another option would be to include all the Non-Cash ASC 715 Reclass accounting entries along with the cash prepayment (sum of Lines 8 and 9, as shown in Line 10). Either way, the end result is the Company's request in this case, which reflects the cash prepayments in rate base.

Q. DO YOU HAVE ANY COMMENTS REGARDING MR. KOLLEN'S STATEMENT THAT "THE COMPANY'S ACCOUNTING REFLECTED IN THESE FOUR ACCOUNTS [1650010, 1650035, 1650014, AND 1650037] IS NOT REQUIRED, DEFINED, OR DESCRIBED BY GAAP OR THE FERC USOA?"

A. Yes. Contrary to AG/KIUC Witness Kollen's claim, prepaid pension and OPEB assets exist under GAAP. Consistent with GAAP, a prepaid pension asset and a prepaid OPEB asset exist when contributions to the related trust fund exceeds the amount of cost that is recorded. Pension and OPEB cost required to be recorded under GAAP is net of the earned return on plan-related investments.

It is important to note that under Statement of Financial Accounting Standards ("SFAS") 87, *Employers' Accounting for Pensions*, the GAAP accounting predecessor to SFAS 158, *Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans* (now codified in ASC 715), the prepaid pension asset is explained as arising from an employer's cumulative cash contributions in excess of cumulative pension cost. Paragraph 35 of SFAS 87, as originally issued, states:

> A liability (unfunded accrued pension cost) is recognized if net periodic pension cost recognized pursuant to this Statement exceeds amounts the employer has contributed to the plan. An asset (prepaid pension cost) is recognized if net periodic pension cost is less than amounts the employer has contributed to the plan.

Q. DO CURRENT ACCOUNTING STANDARDS STILL USE THE ABOVE APPROACH FOR CALCULATING A PREPAID PENSION ASSET?

A. Yes, the prepayment continues to represent the difference between cash contributions to the plan trust fund and the actuarially determined cost recorded on the books. Kentucky Power Company implemented SFAS 158 (now codified in ASC 715), which results in accounting entries (Non-Cash ASC 715 Reclass) to separate the calculated prepayment into two separate components – Kentucky Power Company's funded position (either an asset or liability) and accumulated other comprehensive income or a regulatory asset balance for the timing difference between the amount recorded as expense and the amount recovered from customers over time. The Non-Cash ASC 715 Reclass entry moves amounts between various balance sheet accounts for financial reporting purposes, but doesn't change the character of the original transaction of making a cash contribution to the pension trust and recording pension expense. In the end, a prepayment remains that is separated into two components on the balance sheet – funded position and accumulated other comprehensive income or regulatory asset.

If Kentucky Power Company's contributions to the pension and OPEB trust funds are equal to the GAAP-determined plan cost, there would be no related prepaid asset or liability and the Company would recover this pension and OPEB cost from customers. If Kentucky Power Company's contributions to the pension and OPEB plan trust funds are less than the GAAP-determined plan cost, the Company would have a liability. For periods in which Kentucky Power Company makes contributions above the GAAP-determined cost, the Company has a prepaid asset that, as described above, is a cash asset that has been financed by the Company.

Q. DOES MR. KOLLEN IMPLY THAT THE COMPANY IS NOT COMPLYING WITH GAAP AND ASC 715 IN REGARDS TO ACCOUNTING FOR PREPAID PENSION AND OPEB ASSETS?

A. It is not entirely clear, but it is baseless if that is his assertion. Two different external auditors have issued opinions since ASC 715 was implemented and both auditors have issued “unqualified” or clean opinions regarding the Company’s financial statements and disclosures, including the accounting for Kentucky Power Company’s pension and OPEB plans.

Q. IS WITNESS KOLLEN’S CLAIM THAT “AEP HAS DEFINED THESE ACCOUNTS…TO ASSIST THE OPERATING COMPANIES IN THEIR ATTEMPTS TO INCREASE RATE BASE BY INCLUDING ONLY THE POSITIVE AMOUNTS IN ACCOUNTS 1650010 AND 1650035 IN RATE BASE” ACCURATE?

A. No, this accusation is baseless and incorrect. As stated earlier, the ASC 715 balance sheet accounts are part of reclass entries for financial reporting purposes and zero out, leaving the true cash financed asset. As supported by my direct testimony, the amounts recorded in accounts 1650010 and 1650035 are composed of Kentucky Power’s cumulative cash contributions in excess of cumulative pension and OPEB cost and the Non-Cash ASC 715 Reclass amounts are irrelevant for ratemaking purposes.

Further, the “return on” component of Kentucky Power’s base revenue requirement has historically been computed based on capitalization, which inherently reflects amounts financed by the Company (such as prepaid pension and OPEB amounts) and excludes non-cash transactions. Company Witness Vaughan’s rebuttal testimony supports the Company’s continued use of capitalization to compute the “return on” component of the revenue requirement, as proposed in the Company’s Application. Kentucky Power Company’s consistent approach discredits Mr. Kollen’s claim.

AG/KIUC Witness Kollen is the only witness in this proceeding proposing that Kentucky Power transition to use of rate base to compute the "return on" component of the revenue requirement.

Q. DOES WITNESS KOLLEN ACKNOWLEDGE THAT THE COMMISSION HAS PREVIOUSLY APPROVED A PREPAID PENSION ASSET IN RATE BASE FOR THE COMPANY AND/OR THAT THE PREPAID PENSION ASSET BENEFITS KENTUCKY POWER CUSTOMERS THROUGH REDUCED COST OF SERVICE?

A. No. Mr. Kollen fails to acknowledge that the prepaid pension asset was included in total rate base authorized Case No. 2017-00179, the Company's last base case proceeding. Further, he does not acknowledge that the prepayment benefits customers by reducing pension cost included in the Company's cost of service, as supported by Exhibit HMW-R3.

Q. HAS THE COMMISSION PREVIOUSLY APPROVED A PREPAID OPEB ASSET IN RATE BASE?

A. No. This current proceeding reflects the Company's initial request to include prepaid OPEB asset in rate base. The prepaid OPEB asset was established on the Company's books in March of 2014; however, was inadvertently omitted from rate base presented in the Company's base case filings in Case No. 2014-00396 (historical test year ended September 30, 2014) and Case No. 2017-00179 (historical test year ended February 28, 2017). The prepaid OPEB asset has benefitted customers since its establishment in 2014 by reducing pension cost included in the Company's cost of service to a negative amount, as supported by Exhibit HMW-R3.

Q. DOES WITNESS KOLLEN ACKNOWLEDGE THAT THE PREPAID OPEB ASSET BENEFITS KENTUCKY POWER CUSTOMERS THROUGH REDUCED COST OF SERVICE?

A. No, Mr. Kollen is proposing to remove the prepaid OPEB asset from rate base without making a corresponding adjustment to remove the related benefit of reduced OPEB cost from the cost of service.

Q. DOES YOUR SILENCE ON A PARTICULAR COMMENT OR ASSERTION IN WITNESS KOLLEN'S TESTIMONY REGARDING PENSION AND OPEB ASSETS MEAN THAT YOU AGREE WITH SUCH COMMENT OR ASSERTION?

A. Absolutely not. I limited my rebuttal to the most significant issues on this subject raised in his testimony.

Q. WHY IS IT APPROPRIATE THAT THE COMPANY BE ALLOWED TO INCLUDE ITS PREPAID PENSION AND OPEB ASSETS IN RATE BASE?

A. Kentucky Power Company has prepaid allowable pension and OPEB expenses and the inclusion of the prepayments in rate base is consistent with well-accepted ratemaking principles and Commission precedents and is necessary both to compensate the Company for use of the investor funds it has advanced and to avoid a disincentive to the Company for making similar prudent advances in the future on behalf of its employees. Such treatment is particularly warranted where, as here, the prepayments lowered both the current and future cost of providing service and thus benefited customers and the Company's ongoing ability to provide reliable service along with providing assurance to the Company's employees that there will be funds to pay their retirement benefits.

Q. IS AN ADJUSTMENT TO THE COST OF SERVICE WARRANTED IF THE COMMISSION ADOPTS AG/KIUC WITNESS KOLLEN'S RECOMMENDATIONS TO COMPUTE THE "RETURN ON" COMPONENT OF THE REVENUE REQUIREMENT USING RATE BASE AND REMOVE PREPAID PENSION AND OPEB ASSETS FROM RATE BASE?

A. Yes, because without these additional contributions, the Company's pension and OPEB expense would be higher. Thus, if the pension and OPEB prepayments are removed from rate base, the Company's cost of service for the test year ended March 31, 2020 should be increased in order to remove $3.7 million benefit (lower expense) resulting from these additional contributions, as supported by Exhibit HMW-R3.

IV. CONCLUSION

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes, it does.

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E-Signature Summary

Signer 1: Heather M. Whitney (HMW)
November 03, 2020 10:36:31 -8:00 [5D41CF5B6386] [167.239.221.84]
hmwhitney@aep.com (Principal) (Personally Known)

E-Signature Notary: Sarah Smithhisler (SRS)
November 03, 2020 10:36:31 -8:00 [F11A75C32513] [167.239.221.81]
srsmithhisler@aep.com
I, Sarah Smithhisler, did witness the participants named above electronically sign this document.

VERIFICATION

The undersigned, Heather M. Whitney, being duly sworn, deposes and says she is the Director in Regulatory Accounting Services for American Electric Power Service Corporation that she has personal knowledge of the matters set forth in the forgoing responses and the information contained therein is true and correct to the best of her information, knowledge and belief after reasonable inquiry.

Heather M. Whitney
Signed on 2020/11/03 10:36:31 -8:00

____
Heather M. Whitney

STATE OF OHIO)
) Case No. 2020-00174
COUNTY OF FRANKLIN)

Subscribed and sworn to before me, a Notary Public in and before said County and State, by Heather M. Whitney this 3rd___ day, of November 2020.

S. Smithhisler
Signed on 2020/11/03 10:36:31 -8:00

____
Notary Public

Notary ID Number: 2019-RE-775042

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

Electronic Application Of Kentucky Power Company	)	
For (1) A General Adjustment Of Its Rates For	)	
Electric Service; (2) Approval Of Tariffs And Riders;	)	
(3) Approval Of Accounting Practices To Establish	)	Case No. 2020-00174
Regulatory Assets And Liabilities; (4) Approval Of A	)	
Certificate Of Public Convenience And Necessity,	)	
And (5) All Other Required Approvals And Relief	)	

REBUTTAL TESTIMONY OF

ALLYSON M. KEATON

ON BEHALF OF KENTUCKY POWER COMPANY

REBUTTAL TESTIMONY OF
ALLYSON M. KEATON ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

CASE NO. 2020-00174

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EXHIBITS

EXHIBIT	DESCRIPTION
EXHIBIT AMK R1	AG_KIUC_1_070 – State Income Tax Rate

**REBUTTAL TESTIMONY OF
ALLYSON M. KEATON ON BEHALF OF
KENTUCKY POWER COMPANY BEFORE THE PUBLIC SERVICE
COMMISSION OF KENTUCKY**

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS AND PRESENT POSITION.

A. My name is Allyson M. Keaton. I am a Tax Analyst Principal – Tax Accounting and Regulatory Support for American Electric Power Service Corporation, a wholly owned subsidiary of American Electric Power Company, Inc. ("AEP"), the parent company of Kentucky Power Company ("Kentucky Power" or the "Company"). My business address is 1 Riverside Plaza, Columbus, Ohio 43215.

Q. ARE YOU THE SAME ALLYSON M. KEATON WHO OFFERED DIRECT TESTIMONY IN THIS PROCEEDING?

A. Yes.

II. PURPOSE OF REBUTTAL TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. The purpose of my rebuttal testimony is to rebut Attorney General and Kentucky Industrial Utility Customers, Inc. ("AG/KIUC") Witness Kollen's recommendation that the Kentucky Public Service Commission (the "Commission") should calculate state income expense using the Kentucky state income tax rate instead of a blended rate, and to agree with Witness Kollen's statement that accumulated deferred income taxes ("ADIT") should be excluded for Pension and OPEB Contra-Assets.

Q. WHAT ARE THE EXHIBITS YOU ARE SPONSORING IN THIS PROCEEDING?

A. I am sponsoring the following rebuttal exhibit:

- Exhibit AMK-R1 – AG_KIUC_1_070 – State Income Tax Rate

Q. ARE YOU SPONSORING ANY REBUTTAL SCHEDULES?

A. No.

III. BLENDED STATE INCOME TAX RATE

Q. DO YOU AGREE WITH AG/KIUC WITNESS KOLLEN'S RECOMMENDATION THAT THE COMMISSION SHOULD CALCULATE THE COMPANY'S STATE INCOME TAX EXPENSE USING ONLY KENTUCKY'S STATE INCOME TAX RATE FOR BASE AND RIDER REVENUE REQUIREMENT PURPOSES?

A. No. The Commission should approve Kentucky Power's use of a blended state income tax rate for the current base case and rider revenue requirements in Kentucky. AG/KIUC Witness Kollen is correct that the Company's proposed blended state rate of 5.8545% reflects state income tax rates from Illinois, Michigan, and West Virginia, because of nexus in the particular states. Specifically, as explained in Exhibit AMK-R1, the Company has electricity sales through PJM in Illinois and Michigan, employees with payroll in West Virginia, and property in West Virginia with the Mitchell Plant. As a result, Kentucky Power incurs income tax liability in connection with its operations in these states.

Q. DOES MR. KOLLEN CONTEND THAT THE BLENDED STATE INCOME TAX RATE PROPOSED BY THE COMPANY INCLUDES STATE INCOME TAX CHARGED TO AEP ENTITIES OTHER KENTUCKY POWER?

A. Yes. Mr. Kollen appears to believe that the blended state income tax rate that is used in the base and rider revenue requirements is for all or some of the AEP consolidated entities, not just Kentucky Power Company. However, the Company's Income is apportioned and subjected to the Illinois, Michigan, and West Virginia income taxes based on nexus in those states. Therefore, reflecting only the Kentucky state income tax rate in the Company's base and rider revenue requirements, as recommended by Witness Kollen, would not represent the true cost of Kentucky Power's business and should be denied.

Q. DOES MR. KOLLEN CONTEND THAT THE COMPANY'S BLENDED INCOME TAX RATE WAS CALCULATED INCORRECTLY?

A. No.

Q. IS THE COMPANY'S PROPOSED BLENDED STATE TAX RATE OF 5.8545% CONSISTENT WITH STATE TAX RATES APPROVED IN PREVIOUS KENTUCKY PROCEEDINGS?

A. Yes. The blended state tax rate approved in the Company's 2017 and 2014 base cases were 5.8742% and 5.7348%, respectively.

Q. IS THE COMPANY'S PROPOSED BLENDED STATE INCOME TAX RATE REASONABLE?

A. Yes. The Company's proposed state income tax reflects Kentucky Power's actual costs of providing service to its customers and, as demonstrated above, the 5.8545% is consistent with the blended state income tax rate approach approved by the Commission in the Company's most two recent base case filings, Case Nos. 2014-00396 and 2017-00179, respectively. As such, I recommend the Commission approve the Company's proposed blended state income tax rate of 5.8545%.

IV. ADIT OF PENSION & OPEB CONTRA-ASSETS

Q. DO YOU AGREE WITH AG/KIUC WITNESS KOLLEN'S STATEMENT REGARDING ADIT EXCLUSION OF PENSION AND OPEB CONTRA-ASSETS?

A. Yes. The ADIT should follow the pension and OPEB amounts that are excluded in the cost of service. Thus, the Company agrees that, should the prepaid pension asset and prepaid OPEB asset be included in rate base with no offset for the two related contra-assets, the ADIT related to the pension and OPEB contra-assets should be excluded. Witness Whitney discusses, in her rebuttal, the reason prepaid pension and OPEB assets are included and related contra-assets are excluded in the filing.

V. CONCLUSION

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes, it does.

Kentucky Power Company
KPSC Case No. 2020-00174
AG-KIUC First Set of Data Requests
Dated August 12, 2020

DATA REQUEST

AG_KIUC_1_070 Refer to Workpaper S-2.
a. Explain why the Commission should not limit the state income tax to Kentucky in lieu of apportionments of the Kentucky state income tax rate and other AEP state income tax rates.
b. Address why such apportionments do not constitute subsidies from Kentucky to other states for ratemaking purposes.
c. Address why such apportionments do not directly contradict the Commission's Orders in other proceedings ruling that federal income tax expense be calculated on a standalone basis and that it exclude all consolidated tax savings benefits, including the income tax expense savings from interest on debt at an upstream affiliate used to finance the parent's equity investment in the jurisdictional utility.

RESPONSE

a. MI, IL and WV state income taxes are included in the calculation of the Company's state income tax expense since the Company has nexus in those states as a result of having ownership of property or having specific sales or other activities within each of those states. Therefore, the state income tax expense is a true cost of Kentucky Power's business and should be included in state income tax for Kentucky.

b. See response KPCO_R_KIUC_AG_1_70_a.

c. The Company objects to this request on the basis that the request is vague and ambiguous as it is unclear which Commission orders and/or proceedings the request references. Further, the Company objects to this request on the basis that Commission orders related to the calculation of federal income tax expense are not relevant to the Company's apportionment of state income tax rates. Subject to and without waiving the foregoing objections, the Company states that the apportionments included represent Kentucky Power's stand-alone basis, not any of the Company's affiliates.

Witness: Allyson M. Keaton

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E-Signature 1: Allyson Keaton (AK)
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E-Signature Notary: Sarah Smithhisler (SRS)
October 30, 2020 07:06:39 -8:00 [B821F87F455D] [161.235.2.87]
srsmithhisler@aep.com
I, Sarah Smithhisler, did witness the participants named above electronically sign this document.

VERIFICATION

The undersigned, Allyson M. Keaton, being duly sworn, deposes and says she is a Tax Analyst Principle for American Electric Power Service Corporation that she has personal knowledge of the matters set forth in the forgoing responses and the information contained therein is true and correct to the best of her information, knowledge and belief after reasonable inquiry.

Allyson Keaton
Signed on 2020/10/30 07:06:39 -8:00

Allyson M. Keaton

STATE OF OHIO)
) Case No. 2020-00174
COUNTY OF FRANKLIN)

Subscribed and sworn to before me, a Notary Public in and before said County and State, by Allyson M. Keaton, this 30th day of October 2020.

NOTARY PUBLIC
STATE OF OHIO
Sarah Smithhisler
Commission # 2019-RE-775042
Electronic Notary Public
State of Ohio
My Comm Exp. Apr 29, 2024
Notary Stamp 2020/10/30 07:06:39 PST B821F87F455D

S Smithhisler
Signed on 2020/10/30 07:06:39 -8:00

Notary Public

Notary ID Number: 2019-RE-775042

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

Electronic Application Of Kentucky Power Company	)	
For (1) A General Adjustment Of Its Rates For	)	
Electric Service; (2) Approval Of Tariffs And Riders;	)	
(3) Approval Of Accounting Practices To Establish	)	Case No. 2020-00174
Regulatory Assets And Liabilities; (4) Approval Of A	)	
Certificate Of Public Convenience And Necessity;	)	
And (5) All Other Required Approvals And Relief	)	

REBUTTAL TESTIMONY OF

KIMBERLY KAISER

ON BEHALF OF KENTUCKY POWER COMPANY

REBUTTAL TESTIMONY OF
KIMBERLY KAISER ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

CASE NO. 2020-00174

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REBUTTAL TESTIMONY OF
KIMBERLY KAISER ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, POSITION AND BUSINESS ADDRESS.

A. My name is Kimberly Kaiser. My business address is 1 Riverside Plaza, Columbus, Ohio 43215. My position is Director of Compensation for American Electric Power Service Corporation ("AEPSC"), a wholly owned subsidiary of American Electric Power Company, Inc. ("AEP"). AEP is the parent company of Kentucky Power Company (the "Company" or "Kentucky Power"). AEPSC supplies engineering, financing, accounting and other services to AEP's seven electric operating companies, including the Company. In this testimony, I will refer to AEPSC, Kentucky Power, and other AEP utility operating companies collectively as the "AEP System."

Q. ARE YOU THE SAME KIMBERLY KAISER WHO OFFERED DIRECT TESTIMONY IN THIS PROCEEDING?

A. Yes.

II. PURPOSE OF REBUTTAL TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. The purpose of my rebuttal testimony is to address comments made by Attorney General and Kentucky Industrial Utilities Customers ("AG/KIUC") Witness Lane Kollen with respect to compensation expenses included in the Company's filing. I will explain that incentive compensation expenses, as part of market competitive total compensation, are a reasonable and necessary cost of providing service to and benefitting customers. I will also show that non-qualified post-retirement plan expenses are reasonable and appropriate costs to be included in rate base**.**

III. SHORT-TERM INCENTIVE COMPENSATION

Q. PLEASE EXPLAIN YOUR UNDERSTANDING OF AG/KIUC WITNESS KOLLEN'S USE OF THE TERM "INCENTIVE COMPENSATION PLAN" OR "ICP" IN HIS TESTIMONY.

A. I understand AG/KIUC Witness Kollen's use of "Incentive Compensation Plan" and "ICP" to refer to the Company's variable annual (or short-term) incentive compensation or "STI" as referred to in my direct testimony.

Q. WHAT ADJUSTMENTS HAVE BEEN PROPOSED BY AG/KIUC WITNESS KOLLEN WITH RESPECT TO THE COMPANY'S REQUESTED LEVEL OF STI?

A. AG/KIUC Witness Kollen recommends that the Commission disallow all STI expenses because, he claims, those amounts are tied to achieving shareholder goals and are not directly tied to the achievement of regulated utility service requirements.

Q. DO YOU AGREE WITH AG/KIUC WITNESS KOLLEN'S RECOMMENDATION?

A. No, I do not. The Company is only seeking to recover STI expenses at a target level, which is set based on market median data. Further, AG/KIUC Witness Kollen seems to conflate the EPS funding mechanism and the STI expense the Company is seeking to recover as part of this proceeding. Although the STI expense sought to be recovered is based on the EPS funding target, the allocation of the EPS funds to employees, and therefore the cost incurred by the Company, is based on performance goals which include a balanced scorecard of customer experience, financial, operational, and employee and contractor safety metrics. Thus, the STI expenses the Company is seeking to recover as part of this proceeding are directly tied to achieving customer and safety goals and are a reasonable expense that should be recovered as part of this proceeding.

Q. PLEASE DESCRIBE THE STI TARGET LEVEL THE COMPANY SEEKS TO RECOVER.

A. Target labor cost, including incentive compensation, is the amount the Company, and the AEP System as a whole, needs to pay employees on average to attract and retain talent. The incentive compensation costs the Company is requesting recovery of in this proceeding are the STI funded amounts equivalent to a 100% AEP System funding score. As shown in Table 1 below, the AEP System funding score exceeded target in eight of the last ten years. However, the Company is only seeking to recover its target costs.

Table 1
Funding Score by Performance Year

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Overall Funding Score	113.5%	97.8%	151.4%	162.9%	182.7%	191.0%	170.5%	92.0%	144.9%	172.3%

Q. HOW WAS THE TARGET COMPENSATION FUNDING AMOUNT DETERMINED?

A. The AEP System participates in large energy services and general industry compensation surveys that are administered by a leading data services and professional solutions firm. The most recent energy services survey included over 150 companies and over 250,000 incumbents. The AEP System also participates in the largest survey available for the physical craft workforce; the most recent survey included data from 45 companies and over 70,000 incumbents.

The results of these surveys are used to determine market median for base salaries and incentives. The AEP System uses this median data to set the target compensation funding, meaning that essentially half of the incumbents surveyed have target compensation levels above the AEP System's target compensation funding levels. As one of the largest utilities in the nation, targeting the middle of the market is a very reasonable and conservative approach.

Q. CAN YOU GIVE SOME EXAMPLES DEMONSTRATING THAT THE AEP SYSTEM IS PAYING MARKET MEDIAN COMPENSATION?

A. Yes. Table 2 below shows comparisons of some of the AEP System's average total compensation target as compared to the market median. Job 1 is a physical craft role in Kentucky and shows that the Company is slightly below market median on average for this role. Anything within plus or minus ten percent is considered market competitive for physical craft positions. Job 2 and Job 3 are non-exempt and exempt jobs respectively in Kentucky, and the table shows that the Company is paying slightly above market median for Job 2 and below market median for Job 3. Job 4 is a Long Term Incentive Plan ("LTIP") eligible role in AEPSC and the average pay for this role is also slightly below market. For Job 2, Job 3, and Job 4, the market competitive range is plus or minus fifteen percent. When comparing target compensation to market, all of these roles are within the market competitive range showing that we are in fact not targeting excessive compensation levels. Table 2 also shows that incentives are a necessary component of total compensation in order to keep up with market.

Table 2
AEP Compensation Compared to Market Data

	AEP				Market Median				AEP to Market	
	Average Base	**ICP Target**	**LTIP Target**	**Average Total Comp at Target**	**Base**	**ICP Target**	**LTIP Target**	**Total Comp Target**	**Base**	**Total Comp**
Job 1	$ 84,365	5%		$ 88,583	$ 85,247	5%		$ 90,100	-1.0%	-1.7%
Job 2	$ 57,185	5%		$ 60,044	$ 55,215	5%		$ 55,317	3.6%	8.5%
Job 3	$ 88,884	10%		$ 97,772	$ 96,729	10%		$105,931	-8.1%	-7.7%
Job 4	$ 143,025	20%	$ 7,000	$ 178,630	$ 148,569	18%	$ 6,900	$180,880	-3.7%	-1.2%

Note: AEP compensation in Table 2 is as of December 31, 2019; market data is aged to December 31, 2019

Q. ON WHAT BASIS DO YOU MAKE THE CLAIM THAT TARGET COMPENSATION INCLUDING INCENTIVES IS NECESSARY TO ATTRACT AND RETAIN TALENT?

A. Regardless of the metrics, financial or operational, market competitive pay is needed to attract and retain talent. The AEP System does not pay employees at the top of the market. It is reasonable and prudent to target the middle of the market to remain competitive in attracting and retaining skilled and experienced employees. Reducing total compensation levels, by eliminating or lowering STI, does not provide Kentucky Power with the ability to compensate its employees competitively, which in turn could affect the local economy and the Company's ability to serve customers in the most efficient manner.

Q. DO YOU AGREE WITH AG/KIUC WITNESS KOLLEN THAT THE COMPANY'S STI EXPENSES WERE INCURRED TO INCENTIVIZE THE ACHIEVEMENT OF SHAREHOLDER GOALS AND NOT TO INCENTIVIZE THE ACHIEVEMENT OF CUSTOMER AND SAFETY GOALS?

A. No, I do not. The Company's annual incentive compensation primarily benefits customers. While *funding* for the overall 2019 corporate plan was based primarily on EPS, the Company's scorecard, which determined the payouts to Kentucky Power employees, was primarily focused on customer service, workforce development and operational initiatives. In fact, for 2019, as shown in Table 3 below, only 10% of the Company's scorecard was attributed to a financial measure. The operating measures are the focus of the Company's incentive plan, not the *funding* measures, since those are the only measures to which most employees can contribute.

Table 3
Operating Company ICP Framework

	Metric	Weighting
Customer (15%)	JD Power Corporate Citizenship Score	5%
	Ease of Doing Business	10%
Workforce Development (35%)	DART Rate - Employees and Contractors	5%
	Total Recordable Incident Rate - Employees and Contractors	5%
	Proactive Safety Performance	20%
	Advanced Distribution Lineman Training	2.5%
	Culture Action Plans	2.5%
Operational Excellence (20%)	SAIDI Actual	5%
	SAIDI Work plan	10%
	Sustainable Efficiency Gains	5%
Strategic Goals (20%)	Work plan customized by Operation Company	20%
Financial (10%)	Net Income	5%
	ROE	5%

Furthermore, it is incorrect to characterize incentive pay as only relating to actions that benefit shareholders rather than customers. Kentucky Power provides incentive compensation to virtually all of its employees, but very few recipients of incentive compensation are in a position to affect EPS in ways other than controlling costs and improving efficiencies. Moreover, it is worth repeating that, although EPS is a component of Kentucky Power's incentive compensation funding measures, Kentucky Power's employees are far more motivated by achieving the operating performance measures, the large majority of which encourage employees to take actions that improve Kentucky Power's ability to provide safe and reliable electric service to customers, thus directly benefitting the customers.

Q. WHY DID THE AEP SYSTEM CHANGE ITS INCENTIVE FUNDING METRIC TO 100 PERCENT EPS FOR 2020?

A. In May 2020, the AEP System announced that EPS performance will be the only funding metric for the 2020 STI plan year. It is imperative to focus on the importance of operational efficiencies and cost reduction during a difficult economic time as a result of the global pandemic. This decision to move to a single EPS metric is driven by the unique and unprecedented nature of 2020. The original funding metrics that were part of the initially planned scorecard will continue to be measured and will be considered for discretionary funding adjustments. Employees have been encouraged strongly to not lose sight of safety, compliance, and strategic initiatives to enable the Company and the AEP System to continue to serve their customers and communities.

Q. DO YOU AGREE WITH WITNESS KOLLEN'S RECOMMENDATION THAT STI TIED TO FINANCIAL METRICS SHOULD BE EXCLUDED FROM THE COMPANY'S EXPENSE RECOVERY?

A. No, I do not. It is logical for a corporation to balance financial and operational performance. One should not be sacrificed for the other. It would likely be much easier to exceed all operational goals if there aren't any financial parameters. And again, the EPS goal is a large part of the overall funding, but any payouts to Kentucky Power employees serving Kentucky customers are mostly focused on operational metrics.

Furthermore, the AEP System needs to provide employees with market competitive pay to attract and retain the necessary talent and experience to provide safe and reliable service to its customers. Therefore I would ask that the focus be on whether targeted compensation is reasonable and not on the metrics on which it is measured. If the financial metric included in the performance plan were excluded, the Company would either need to replace that metric with another operational goal or increase employees base pay to account for the lost incentive compensation. Eliminating a portion of compensation without replacing it with something else would mean the Company would be unable to provide market competitive compensation, which would be to the detriment of Kentucky Power's customers.

Thus, the Company has shown with substantive and sufficient evidence that its STI program is a critical component of market competitive total compensation that benefits customers by enabling the Company to attract and retain the employees needed to efficiently and effectively provide its service to customers. Neither the need for market competitive total compensation nor the appropriate level of such compensation is contested in the testimony in this case.

Q. ARE THERE ANY OTHER REASONS WHY YOU DISAGREE WITH AG/KIUC WITNESS KOLLEN'S RECOMMENDATIONS ON INCENTIVE COMPENSATION?

A. Yes. It is not proper for the companies to "charge" employee compensation costs to shareholders when this compensation is a reasonable, prudent and necessary expense for Kentucky Power. It is not accurate to infer that shareholders are the main beneficiaries of the funding pool, when it is simply a mechanism to provide goal oriented variable compensation which directly encourages employees to reduce expense, and operate safely and efficiently to provide reliable service to Kentucky Power customers.

Q. HAS THE COMMISSION PREVIOUSLY ADDRESSED WHETHER EXCLUSION OF THE COMPANY'S STI EXPENSE SHOULD BE BASED ON THE COMPANY'S EPS FUNDING MECHANISM OR THE PERFORMANCE MEASURES OF THE COMPANY'S STI?

A. Yes. In the Commission's Order in Case No. 2014-00396, the Commission, in denying the Attorney General's recommendation that 75% of the Company's ICP expense be excluded because it was funded by EPS, found that, "the amount that should be removed for ratemaking purposes should be based on the performance measures of the plan, not the funding measures."[1] Consistent with that Order, the Company

[1] Order of the Kentucky Public Service Commission, Case No. 2014-00396, June 22, 2015, pp. 25-26.

recommends that the Commission deny Mr. Kollen's recommendation to disallow all of the Company's STI expense based on the EPS funding mechanism.

IV. LONG-TERM INCENTIVE COMPENSATION

Q. DO YOU AGREE WITH AG/KIUC WITNESS KOLLEN'S STATEMENT THAT THE COMPANY'S LTIP IS USED TO ACHIEVE SHAREHOLDER GOALS AND, THEREFORE, IS NOT DIRECTLY TIED TO THE ACHIEVEMENT OF REGULATED UTILITY SERVICE REQUIREMENTS?

A. No. The primary objective of the Companies' long-term incentive plan is to provide an integral component of the reasonable and market competitive compensation needed to attract, retain and motivate the appropriately skilled and experienced employees necessary to efficiently and effectively provide electric service to customers. This fundamental aspect of the AEP System compensation plan clearly benefits both customers and the Company. Furthermore, the financial measures included in the performance unit portion of the Companies' long-term incentive compensation benefit customers by providing an incentive to control costs, which is the primary and often only lever most utility employees have available to improve company financial performance.

Additionally, starting with the 2020 LTIP, a new performance factor was added to boost the percentage of clean energy in its generation mix. This factor aligns with a strategy to commit resources to reduce greenhouse gas emissions. The addition of this factor, supports the AEP System's determination to support a more balanced generation portfolio, including renewable components that can provide a clean energy future for our customers and is not tied to achieving shareholder financial goals.

Finally, the restricted stock portion of LTIP is tied primarily to participant retention through vesting requirements and granted awards are at market competitive compensation levels. Actual value at vesting will be based on the stock price at that time. Retention of talent benefits customers through experienced employees with a strategic, long-term focus on providing reliable service, operational efficiencies and cost control.

Q. IS THE AEP SYSTEM'S LTIP NECESSARY TO PROVIDE SERVICE TO KENTUCKY POWER'S CUSTOMERS?

A. Yes. As shown in Table 2 above, the absence of long-term incentives in Job 4, which is a position that would be eligible for LTIP, would mean pay below market competitive total compensation. Disallowance of the recovery of LTIP expenses, for positions that would otherwise be eligible for LTIP to bring total compensation to a market competitive level, could lead to turnover and lost productivity in critical roles which lead to higher costs to customers. Table 2 also shows that the AEP System does not offer LTIP to jobs where it is not part of market competitive compensation. Therefore, overall targeted LTIP expense is only what is needed to remain at market competitive total compensation and to attract and retain talent necessary to provide safe and efficient service to Kentucky Power customers.

Q. SHOULD RECOVERY OF LTIP EXPENSES TIED TO FINANCIAL MEASURES BE ALLOWED?

A. Yes. As with short-term incentives, LTIP is a customary component of total compensation or certain jobs. Therefore, the focus should be on the levels of LTIP the Company is providing and recognition that this level is equivalent to market median.

Long-term incentives are awarded in the form of equity which logically has financial measures. As mentioned above, there are several benefits to customers including cost control and retention of experience employees, as well as allowing the Company to provide market competitive compensation to its employees in Kentucky.

V. POST-RETIREMENT BENEFITS

Q. PLEASE EXPLAIN THE COMPANY'S POST-RETIREMENT BENEFITS.

A. The Company maintains non-qualified post-retirement benefit plans for its employees to provide benefits that cannot be provided under qualified post retirement plans due to IRS limits imposed on ERISA-qualified plans. These plans are commonly referred to as Supplemental Employee Retirement Plans or "SERPs." The Company utilizes such plans to provide the same retirement benefits to employees as are provided under the ERISA-qualified retirement plans to the extent that such benefits cannot be provided due to the constraints imposed on qualified plans. The AEP System's non-qualified pension plans use the same benefit formulas as are used under the qualified Retirement Plan for each respective employee, except that the non-qualified benefits are reduced by the amount of qualified benefits. Therefore, the total benefit provided by the Company under both its qualified and non-qualified retirement plans is equal to the benefit that would be produced by the formulas utilized under the qualified retirement plans if these plans were not subject to the benefit limitations imposed on qualified plans.

Q. WHAT IS AG/KIUC WITNESS KOLLEN'S RECOMMENDATION AS TO THE SERP EXPENSES THE COMPANY SEEKS TO RECOVER IN THIS PROCEEDING?

A. AG/KIUC Witness Kollen recommends that the Commission disallow SERP expense based on the Commission's previous orders prohibiting excessive expenses incurred pursuant to multiple retirement plans.

Q. DO YOU AGREE WITH AG/KIUC WITNESS KOLLEN'S THAT THE AEP SYSTEM'S SERP IS AN EXCESSIVE EXPENSE INCURRED PURSUANT TO MULTIPLE RETIREMENT ACCOUNTS?

A. No. The Company's non-qualified deferred compensation benefits have been designed as part of the market competitive total rewards package, which the Company provides to all employees whose skills and experience command higher pay in the market. It is not an additional benefit above and beyond what is needed to provide market-competitive total rewards to these employees or high quality service to customers. As such, customers benefit from the provision of these benefits as part of a market-competitive total rewards package in the same way as they benefit from the provision of base pay as part of the same market competitive package.

Q. HAS THE COMMISSION PREVIOUSLY MADE A DETERMINATION ON THE REASONABLENESS OF THE COMPANY'S SERP EXPENSE?

A. Yes. In Case No. 2017-00179, the Attorney General recommended adjustments for the expense associated with the Company's SERP arguing that such plans provide benefits to executives that exceed amounts limited in qualified retirement plans by the Internal Revenue Service and that additional retirement compensation to the Company's highest paid executives is not a reasonable expense that should be recovered in rates. In its January 18, 2018 Order, the Commission found, "the [Company's] SERP expenses reasonable and, therefore, should be allowed for ratemaking purposes."[2] The Company recommends that Commission find the Company's SERP expense is reasonable consistent with their previous ruling in Case No. 2017-00179.

VI. CONCLUSION

Q. DO YOU HAVE ANY FINAL COMMENTS?

A. My testimony demonstrates that the AEP System and the Company are deliberate and prudent in targeting median market competitive pay for all components of total compensation. These competitive labor costs, which include STI, LTIP and SERP, also allow the Company to offer good, fairly paid jobs in the local market in Kentucky. Therefore, the focus should be on whether or not the Commission agrees that the compensation amounts are reasonable. The focus should not be on how the AEP System or the Company funds its incentive plans or measures performance against incentive metrics and whether or not these metrics are tied to financial or operational goals. The bottom line is that the Company is and will continue to incur these expenses in order to maintain the workforce necessary to provide service to our customers. The AEP System, including Kentucky Power, is in business to serve customers in the most efficient and reliable manner possible. This service logically comes with a cost of doing business, which includes market competitive labor expenses.

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes, it does.

[2] Order of the Kentucky Public Service Commission, Case No. 2017-00179, January 18, 2018, p. 16.

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E-Signature Summary

E-Signature 1: Kimberly Kaiser (KK)
October 29, 2020 08:08:59 -8:00 [5291B8062F54] [167.239.221.80]
kkkaiser@aep.com (Principal) (Personally Known)

E-Signature Notary: Sarah Smithhisler (SRS)
October 29, 2020 08:08:59 -8:00 [A41D1A379EDF] [161.235.2.86]
srsmithhisler@aep.com
I, Sarah Smithhisler, did witness the participants named above electronically sign this document.

VERIFICATION

The undersigned, Kimberly K. Kaiser, being duly sworn, deposes and says she is a Director of Compensation for American Electric Power Service Corporation that she has personal knowledge of the matters set forth in the forgoing responses and the information contained therein is true and correct to the best of her information, knowledge and belief after reasonable inquiry.

5291B8062F54

Signed on 2020/10/29 08:08:59 -8:00

____

Kimberly K. Kaiser

STATE OF OHIO	)	
	)	Case No. 2020-00174
COUNTY OF FRANKLIN	)	

Subscribed and sworn to before me, a Notary Public in and before said County and State, by Kimberly K. Kaiser, this 29th day of October 2020.

A41D1A379EDF

Signed on 2020/10/29 08:08:59 -8:00

____

Notary Public

Notary ID Number: 2019-RE-775042

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

Electronic Application Of Kentucky Power Company For (1) A General Adjustment Of Its Rates For Electric Service; (2) Approval Of Tariffs And Riders; (3) Approval Of Accounting Practices To Establish Regulatory Assets And Liabilities; (4) Approval Of A Certificate Of Public Convenience And Necessity; And (5) All Other Required Approvals And Relief	)))))))	Case No. 2020-00174

REBUTTAL TESTIMONY OF

FRANZ D. MESSNER

ON BEHALF OF KENTUCKY POWER COMPANY

REBUTTAL TESTIMONY OF
FRANZ D. MESSNER ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

CASE NO. 2020-00174

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REBUTTAL TESTIMONY OF
FRANZ D. MESSNER ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Franz D. Messner, and my business address is 1 Riverside Plaza, Columbus, Ohio, 43215.

Q. BY WHOM ARE YOU EMPLOYED AND WHAT IS YOUR POSITION?

A. I am employed by American Electric Power Service Corporation ("AEPSC") as Managing Director of Corporate Finance. AEPSC supplies engineering, financing, accounting, planning, advisory, and other services to the subsidiaries of the American Electric Power ("AEP") system, one of which is Kentucky Power Company ("Kentucky Power" or the "Company").

Q. ARE YOU THE SAME FRANZ D. MESSNER WHO OFFERED DIRECT TESTIMONY IN THIS PROCEEDING?

A. Yes.

II. PURPOSE OF REBUTTAL TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. The purpose of my Rebuttal Testimony is to respond to certain recommendations in the Direct Testimony of Lane Kollen for the Office of the Attorney General of the Commonwealth of Kentucky and Kentucky Industrial Utility Customers, Inc. (jointly, "AG/KIUC"). Specifically, I address certain proposals by Mr. Kollen to adjust the amount and cost of short-term and long-term debt included in the Company's weighted average cost of capital. I also discuss credit ratings and their importance. Finally, I discuss the impacts to credit metrics associated with the amortization of unprotected excess accumulated deferred federal income tax ("ADFIT"), consistent with the Commission's directive in its Order in Case No. 2020-00176.

III. SHORT- AND LONG-TERM DEBT

Q. ARE THERE LIMITS ON THE AMOUNT OF SHORT-TERM DEBT THE COMPANY CAN BORROW?

A. Yes, Kentucky Power has Federal Energy Regulatory Commission approved authority to issue up to $180 million of short-term debt. As short-term debt builds up the Company issues long-term debt to reduce the short-term debt balance and better match the tenor of the debt with the life of the longer-lived assets being financed.

Q. DID THE COMPANY UTILIZE SHORT-DEBT FINANCING DURING THE TEST YEAR ENDED MARCH 31, 2020?

A. Yes. Kentucky Power was in a borrowed position in the AEP Utility Money Pool at the end of the test year March 31, 2020 and it borrowed short-term debt from the Utility Money Pool during all twelve months of the test year. The Company's monthly Utility Money Pool cash position was provided in the Company's response to KPSC 6-8.

Q. PLEASE SUMMARIZE MR. KOLLEN'S PROPOSED ADJUSTMENTS (AT PAGES 40-41) TO THE COMPANY'S END OF TEST YEAR CAPITAL STRUCTURE.

A. Mr. Kollen recommends the end of test year capital structure be modified to increase the actual end of test year short-term debt balance of $10.536 million to a hypothetical end of test year amount equal to $80.621 million. $80.621 million is Mr. Kollen's calculation of the average amount borrowed during the test year.

Q. MR. KOLLEN SUPPORTS HIS USE OF A HYPOTHETICAL END OF TEST SHORT TERM DEBT BALANCE OF $80.621 MILLION BY NOTING THE COMPANY PAID DOWN ITS FEBRUARY 28, 2020 SHORT TERM DEBT BALANCE OF $120.549 TO THE END OF TEST YEAR AMOUNT OF $10.536 MILLION. WHY DID KENTUCKY POWER REDUCE ITS SHORT TERM BORROWINGS IN FEBRUARY 2020?

A. A long-term private placement debt issuance was contemplated in late 2019 and early 2020 as the amount of short-term debt increased. Due to uncertainty with economic development activity in Kentucky, marketing of a private placement to investors would have been more difficult, and could have adversely affected the interest rate pricing. For this reason, the private placement issuance was delayed and a $125 million two-year term loan was ultimately issued in March to reduce short-term debt.

Q. AT WHAT INTEREST RATE WAS THE TERM LOAN ISSUED THAT WAS USED TO PAY DOWN THE COMPANY'S SHORT TERM DEBT?

A. The test year end March 31, 2020 cost rate for the term note was 1.683%, which is lower than the 2.230% short-term debt interest rate.

Q. DO YOU AGREE WITH MR. KOLLEN'S ASSERTION THAT THE AMOUNT OF SHORT-TERM DEBT INCLUDED IN THE COMPANY'S END OF TEST YEAR CAPITALIZATION IS NOT REASONABLE?

A. No, I do not. Mr. Kollen's assertion that the Company's reliance on short-term debt is not adequately reflected in the end of test year capital structure as of March 31, 2020 is misplaced. In accordance with the Commission's standard filing requirements, the Company included the end of test year per books balance of short-term debt as shown in Section V, Workpaper S-3, Column 3, Line 2.

The end of test year per books balance of short-term debt as shown in Section V, Workpaper S-3, Column 3, Line 2 is approximately $10.536 million. This amount is subsequently adjusted to $0 in the Mitchell Coal Stock Adjustment that Company Witness Vaughan addresses in his Rebuttal Testimony.

Q. DO YOU AGREE WITH MR. KOLLEN'S RECOMMENDATION THAT THE COMPANY SHOULD USE THE MOST RECENT INTEREST RATE ON SHORT-TERM DEBT INCURRED BY THE COMPANY OF 0.51%.

A. No, I do not. The calculation of the 2.230% short-term debt interest rate included in the Section V, Workpaper S-2, Page 1 of 3 is shown in Section V, Workpaper S-3, Page 3 of 4 and is the Company's actual interest expense for the twelve months ended March 31, 2020 divided by the average short-term debt borrowings for the same period. This rate was calculated in a manner consistent with the calculation used in previous rate cases.

Q. DO YOU AGREE WITH MR. KOLLEN'S PROPOSED ADJUSTMENT TO THE COST RATE ON THE $40 MILLION SENIOR UNSECURED NOTES – SERIES A THAT WILL MATURE ON JUNE 18, 2021?

A. No, I do not. Mr. Kollen proposes on pages 41 through 43 of his testimony to adjust the cost rate of the Series A bonds from 7.319% in Section V, Workpaper S-3, Page 2 of 4, Column 11, Line 2 down to 4.0% and defer difference in jurisdictional interest expense between this rate and the current cost rate until it matures as a regulatory asset and then direct the Company thereafter to defer the difference in interest expense between this rate and the actual interest rate on the new debt issue as a regulatory asset (if greater) or as a reduction to the regulatory asset initially deferred (if less) until rates are reset in the next base rate proceeding.

Replacing the existing cost rate on the Series A notes is not appropriate as those notes were part of the historical test year capital structure at March 31, 2020 and remain outstanding. Company Witness West addresses Mr. Kollen's deferral proposal in his Rebuttal Testimony.

IV. <u>CREDIT RATINGS</u>

Q. WHAT IS THE PURPOSE OF CREDIT RATINGS?

A. Credit ratings allow investors to assess the credit risk of a borrower and its anticipated ability to repay its debt obligations.

Q. WHAT IS KENTUCKY POWER'S CURRENT CREDIT RATING?

A. Kentucky Power currently has investment grade credit ratings of A- (Stable) and Baa3 (Stable) with S&P and Moody's, respectively.

Q. GENERALLY DESCRIBE THE METHODOLOGY OF EACH RATING AGENCY.

A. S&P evaluates the credit of each AEP operating company utilizing a family approach that factors in the ratings of all AEP system subsidiaries. S&P's family approach to bond ratings for individual operating companies stresses the inherent benefits and risks associated with having a diversified family of operating companies across AEP's eleven-state service territory.

Unlike S&P's family methodology, Moody's rates each individual operating company based on the merits of the underlying operations and credit profile of that individual operating company. Because rates are only being established for Kentucky Power, Moody's will be my primary focus when discussing Kentucky Power's credit rating.

Q. HOW DOES MOODY'S MEASURE FINANCIAL STRENGTH?

A. Financial strength accounts for 40% of Moody's rating methodology. Moody's financial measures and scores are based on ratios including interest coverage, cash flow to debt, and debt to capitalization.

Q. WHEN WAS THE MOST RECENT MOODY'S RATING ACTIVITY?

A. On April 12, 2019, Moody's downgraded the Company's credit rating to Baa3 from Baa2 indicating the downgrade reflected a deterioration in Kentucky Power's financial profile driven by cash flows that are constrained by deferred cost recovery, a rate case stay-out period, and declining loads. On April 15, 2019, Moody's issued a full updated credit opinion following the downgrade in which it indicated that cash deferrals will continue to be a credit challenge. The opinion did indicate that the Company's reasonable regulatory relationship was a credit strength.

Q. WHAT IMPACT COULD DECREASED CASH FLOWS HAVE ON KENTUCKY POWER'S CREDIT RATING?

A. Further deterioration of Kentucky Power's cash flows could result in ratings downgrade pressure and increased borrowing costs associated with future financing activity. Cash flows from operations are a key component of the ratios utilized to score a company's financial strength.

Q. BRIEFLY SUMMARIZE THE IMPORTANCE OF KENTUCKY POWER'S INVESTMENT GRADE CREDIT RATINGS.

A. Timely and sufficient cost recovery is required to maintain the cash flows necessary to support a stable investment grade credit rating. Having investment grade credit assures the investment community the Company can service its current and future debt obligations and creates the ability to source capital at attractive rates for its customers.

V. ADFIT AND CREDIT METRICS

Q. ARE YOU AWARE THAT IN CASE NO. 2018-00035, THE COMMISSION AUTHORIZED KENTUCKY POWER TO AMORTIZE UNPROTECTED EXCESS ACCUMULATED DEFERRED FEDERAL INCOME TAX RESULTING FROM THE ENACTMENT OF THE TAX CUTS AND JOBS ACT OF 2017 OVER EIGHTEEN YEARS?

A. Yes. It is my understanding, as discussed further by Company Witness Vaughan, that Kentucky Power credits customer bills to reflect that amortization through the Company's Federal Tax Cut Tariff.

Q. GENERALLY SPEAKING, HOW DOES THE TIME PERIOD OVER WHICH KENTUCKY POWER AMORTIZES ITS UNPROTECTED EXCESS ADFIT IMPACT THE COMPANY?

A. Each dollar of amortization reduces the Company's cash flow by a dollar without a compensating reduction in the Company's expenses. Thus, the more quickly the unprotected excess ADFIT is amortized, the greater the impact on Kentucky Power's cash flow, which in turn places pressure on the Company's credit metrics and ultimately its cost of capital. As Company Witness Horeled explained in Case No.

2018-00035, even amortizing the ADFIT over eighteen years places pressure on the Company's credit metrics; however, that pressure is less than would be the case if the Commission had ordered the Company to amortize the unprotected excess ADFIT balance more quickly, such as over a period of five years.

Q. DOES THE AMORTIZATION OF A SIGNIFICANT PERCENTAGE OF KENTUCKY POWER'S UNPROTECTED EXCESS ADFIT BALANCE, AS PROPOSED IN THIS CASE AND CASE NO. 2020-00176, NEGATIVELY IMPACT THE COMPANY'S CREDIT METRICS?

A. Yes, but because that amortization is likely to be viewed by ratings agencies as a one time, single year, limited duration event, the impact on credit ratings will likely be more muted than if the impact were spread over a sustained two to five year period.

Q. WHAT HAS CHANGED SINCE CASE NO. 2018-00035 TO WARRANT THE COMPANY'S CURRENT ADFIT PROPOSALS?

A. The COVID-19 pandemic and related economic implications, including disconnect moratoriums, have resulted in unprecedented increased delays in receipt of customer payments and increased customer arrearages. Company Witnesses Mattison and West explain why the Company has made its ADFIT proposals in recognition of the effects COVID-19 is having on both customers and the Company.

Q. BASED UPON THE COMPANY'S PROPOSALS IN THIS CASE AND CASE NO. 2020-00176, IS THE CREDIT IMPACT OF THE COMPANY'S AMORTIZATION OF THE UNPROTECTED EXCESS ADFIT THE SAME BEGINNING IN 2023 AS IT WAS AS A RESULT OF CASE NO. 2018-00035?

A. Yes. The credit impact beginning in 2023 until the unprotected excess ADFIT balance is fully amortized remains unchanged from the 2018 case because the Company proposes to continue to amortize the remaining balance at the same level going forward. See Direct Testimony of Company Witness Vaughan at p. 33-34. Therefore, the cash flow impacts during that time period are the same as they are under the amortization approved by the Commission in Case No. 2018-00035.

VI. CONCLUSION

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes, it does.

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E-Signature Summary

E-Signature 1: Franz Messner (FDM)
October 30, 2020 08:32:26 -8:00 [1E8A0BA7D444] [167.239.221.80]
fdmessner@aep.com (Principal) (Personally Known)

E-Signature Notary: Sarah Smithhisler (SRS)
October 30, 2020 08:32:26 -8:00 [1B170FB2048D] [161.235.2.87]
srsmithhisler@aep.com
I, Sarah Smithhisler, did witness the participants named above electronically sign this document.

VERIFICATION

The undersigned, Franz D. Messner, being duly sworn, deposes and says he is a Managing Director of Corporate Finance for American Electric Power Service Corporation that he has personal knowledge of the matters set forth in the forgoing responses and the information contained therein is true and correct to the best of his information, knowledge and belief after reasonable inquiry.

Franz Messner
Signed on 2020/10/30 08:32:26 -8:00

Franz D. Messner

STATE OF OHIO)
) Case No. 2020-00174
COUNTY OF FRANKLIN)

Subscribed and sworn to before me, a Notary Public in and before said County and State, by Franz D. Messner, this 30th day of October 2020.

NOTARY PUBLIC
STATE OF OHIO
Sarah Smithhisler
Commission # 2019-RE-775042
Electronic Notary Public
State of Ohio
My Comm Exp. Apr 29, 2024
Notary Stamp 2020/10/30 08:32:26 PST 1B170FB2048D

S Smithhisler
Signed on 2020/10/30 08:32:26 -8:00

Notary Public

Notary ID Number: 2019-RE-775042

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

Electronic Application Of Kentucky Power Company	)	
For (1) A General Adjustment Of Its Rates For	)	
Electric Service; (2) Approval Of Tariffs And Riders;	)	
(3) Approval Of Accounting Practices To Establish	)	Case No. 2020-00174
Regulatory Assets And Liabilities; (4) Approval Of A	)	
Certificate Of Public Convenience And Necessity;	)	
And (5) All Other Required Approvals And Relief	)	

REBUTTAL TESTIMONY OF

ADRIEN M. MCKENZIE, CFA

ON BEHALF OF KENTUCKY POWER COMPANY

REBUTTAL TESTIMONY OF

ADRIEN M. MCKENZIE

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I. INTRODUCTION

Q1. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A1. Adrien M. McKenzie, 3907 Red River, Austin, Texas, 78751.

Q2. ARE YOU THE SAME ADRIEN M. MCKENZIE THAT PREVIOUSLY SUBMITTED PREFILED DIRECT TESTIMONY IN THIS CASE?

A2. Yes, I am.

Q3. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A3. My testimony to the Kentucky Public Service Commission ("Commission") addresses the testimony of Mr. Richard Baudino, submitted on behalf of the Kentucky Office of Attorney General and the Kentucky Industrial Utility Consumers, Inc. (together, "AG/KIUC") concerning the fair rate of return on equity ("ROE") that Kentucky Power Company ("Kentucky Power" or "the Company") should be authorized to earn on its investment in providing electric utility service. I also address ROE-related testimony from Mr. Lane Kollen, on behalf of AG/KIUC, and Mr. James Owen, on behalf of Joint Intervenors.[1] Mr. Baudino accepts the Company's proposed common equity level (at 43.25%) so, for this reason, I do not address this issue further.

Finally, in light of significant changes in capital market conditions since the time the analyses presented in my direct testimony were prepared, I also present updated quantitative analyses using current inputs. These results provide additional confirmation that a 10.0% ROE for Kentucky Power is reasonable.

[1] Joint Intervenors consist of Mountain Association, Kentuckians for the Commonwealth, and the Kentucky Solar Energy Society.

A. Summary of Conclusions

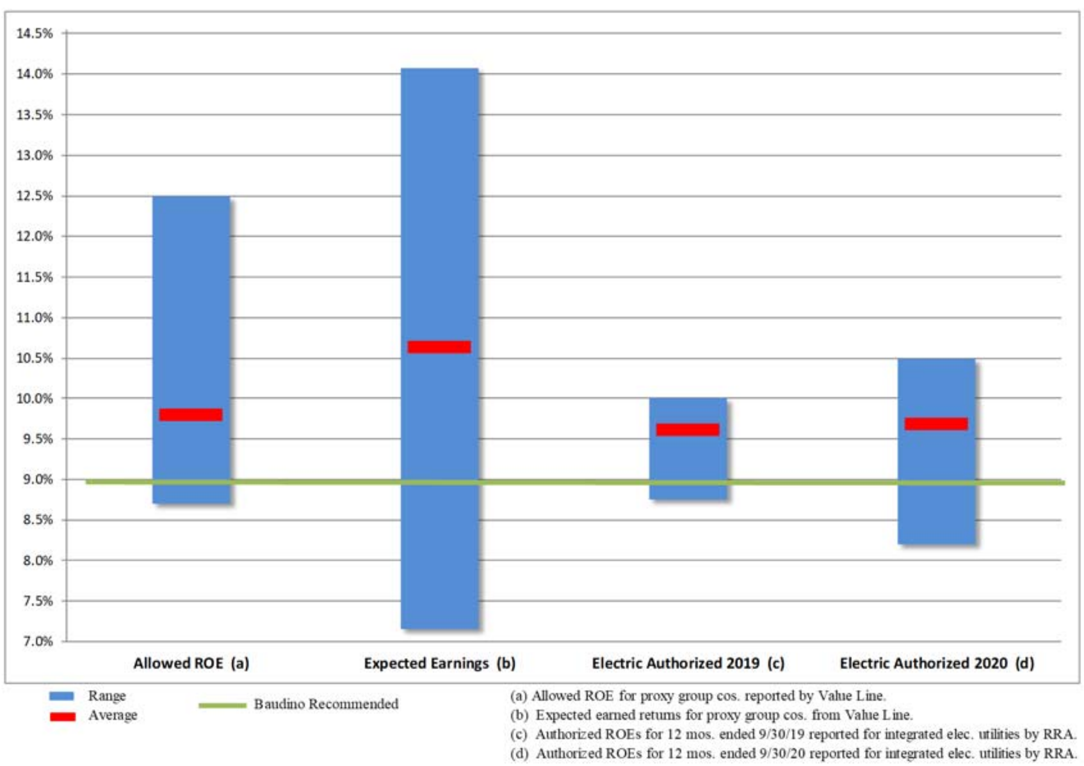
Q4. WHAT ROE IS MR. BAUDINO RECOMMENDING FOR KENTUCKY POWER?

A4. Mr. Baudino recommends an ROE range of 8.93% - 9.25% for the Company. Mr. Kollen discusses additional regulatory policy considerations and recommends that the Commission adopt a 9.0% ROE in this case. Since this recommendation falls within his proposed range, Mr. Baudino supports the 9.0% ROE recommendation.

Q5. PLEASE SUMMARIZE YOUR RESPONSE TO MR. BAUDINO'S TESTIMONY.

A5. His cost of equity recommendation is simply too low and fails to reflect the risk perceptions and return requirements of real-world investors in the capital markets. The significant shortfall between his recommendation and the ROE benchmarks discussed in my rebuttal testimony is illustrated in Figure R-1 below.

FIGURE R-1
COMPARISON OF ROE RECOMMENDATIONS TO BENCHMARKS



Q6. WHAT ARE YOUR PRINCIPAL CONCLUSIONS REGARDING MR. BAUDINO'S 9.0% ROE RECOMMENDATION?

A6. Mr. Baudino's recommendation is below realistic investor expectations. My rebuttal testimony demonstrates that:

- Mr. Baudino's discussion of current capital market conditions is incomplete and potentially misleading.
    - The dramatic increase in market volatility that has accompanied the COVID-19 pandemic is indicative of significantly higher investment risks.
    - Rising beta values supports the view that the forward-looking risks of electric utility stocks have increased, which implies a higher ROE.
- Mr. Baudino fails to apply sufficient checks of reasonableness to test his Discounted Cash Flow ("DCF") results.
- Mr. Baudino failed to evaluate the reasonableness of individual DCF estimates, which undermines the reliability of his conclusions.
- Mr. Baudino's application of the Capital Asset Pricing Model ("CAPM") is compromised by reliance on historical data, while his forward-looking approach is marred by methodological shortcomings and inconsistencies.
- Mr. Baudino's rejection of a flotation cost adjustment contradicts the findings of the financial literature and the economic requirements underlying a fair rate of return on equity.

Furthermore, Mr. Baudino fails to consider the Empirical CAPM ("ECAPM") and risk premium approaches, which are recognized ROE methods. Finally, his criticisms of my size adjustment, market return calculation, expected earnings approach, and non-utility DCF analysis are without merit. Taken as a whole, these shortcomings ensure that Mr. Baudino's recommended ROE range—and the 9.0% ROE recommendation of AG/KIUC—falls well below a fair and reasonable level for the Company's utility operations.

B. Comparison of ROE Recommendation to Accepted Benchmarks

Q7. SHOULD ALLOWED ROES BE USED TO EVALUATE WHETHER MR. BAUDINO'S RECOMMENDED ROE IS INSUFFICIENT TO MEET REGULATORY STANDARDS?

A7. Yes. Allowed ROEs provide a gauge of the reasonableness of the outcome of a particular analysis or decision, but ROE values do not exist in a vacuum. In considering utilities with comparable risks, investors will always prefer to provide capital to the opportunity with the highest expected return. If a utility is unable to offer a return similar to that available from other investment opportunities posing equivalent risks, investors will become unwilling to supply the utility with capital on reasonable terms.

Q8. HOW DOES AG/KIUC'S 9.0% ROE RECOMMENDATION COMPARE TO RECENTLY-ALLOWED RETURNS FROM OTHER STATE COMMISSIONS?

A8. It is significantly below this standard. As shown below in Table R-1, the average ROE allowed for integrated electric utilities by other state commissions in recent years has been 9.69%, or 9.54% through the third quarter of 2020:[2]

[2] As shown on page 3 of Exhibit AMM-8, at no time during the 46-year period referenced in my risk premium study has the annual average authorized ROE for electric utilities been as low as the value recommended by Mr. Baudino in this case.

TABLE R-1
AVERAGE ALLOWED ROE BY STATE COMMISSIONS

Year	Integrated Electric
2017	9.80%
2018	9.68%
2019	9.73%
2020*	9.54%
Average	**9.69%**

*Through September 30, 2020.
Source: S&P Global Market Intelligence, RRA Regulatory Focus, Major Rate Case Decisions – January – September 2020, Regulatory Research Associates (Oct. 20, 2020).

Similarly, the ROE recommendation of AG/KIUC are below the current allowed returns reported to investors for the companies in Mr. Baudino's proxy group, which average 9.79%. These results are presented on Exhibit AMM-13.

Q9. DO THE RESULTS OF THE EXPECTED EARNING APPROACH ALSO INDICATE THAT MR. BAUDINO'S 9.0% ROE RECOMMENDATION IS TOO LOW TO BE CONSIDERED REASONABLE?

A9. Yes. The expected earnings approach is predicated on the comparable earnings test, which developed as a direct result of the United States Supreme Court ("Supreme Court") decisions in *Bluefield*[3] and *Hope*[4], as I discuss in my Direct Testimony.[5] This test recognizes that investors compare the allowed ROE with returns available from other alternatives of comparable risk.

Importantly, the expected earnings approach explicitly recognizes that regulators do not set the returns that investors earn in the capital markets. Regulators can only establish the allowed return on the value of a utility's investment, as reflected on its accounting records. As a result, reference to

[3] *Bluefield Water Works & Improvement Co. v. Pub. Serv. Comm'n*, 262 U.S. 679 (1923) ("Bluefield").
[4] *Fed. Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 591 (1944) ("Hope").
[5] McKenzie Direct at 4-6.

expected earned rates of return helps ensure that the allowed ROE is similar to what other utilities of comparable risk will earn on invested capital. This opportunity cost test does not require theoretical models to indirectly infer investors' perceptions from stock prices or other market data. As long as the proxy companies are similar in risk, their expected earned returns on invested capital provide a direct benchmark for investors' opportunity costs that is independent of fluctuating stock prices, market-to-book ratios, debates over growth rates, or the limitations inherent in any theoretical model of investor behavior.

Q10. HAS THE EXPECTED EARNINGS APPROACH BEEN RECOGNIZED AS A VALID ROE BENCHMARK?

A10. Yes. This method predominated before the DCF model became fashionable with academic experts, and it continues to be used around the country.[6] A textbook prepared for the Society of Utility and Regulatory Analysts labels the comparable earnings approach the "granddaddy of cost of equity methods" and points out that the amount of subjective judgment required to implement this method is "minimal," particularly when compared to the DCF and CAPM methods.[7] The *Practitioner's Guide* notes that the comparable earnings test method is "easily understood" and firmly anchored in the regulatory tradition of the *Bluefield* and *Hope* cases,[8] as well as sound regulatory economics. Similarly, *New Regulatory Finance* concluded that, "because the investment base for ratemaking purposes is

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[6] For example, the Virginia State Corporation Commission is required by statute (Virginia Code § 56-585.1.A.2.a) to consider the earned returns on book value of electric utilities in its region. Another example is the Idaho Public Utilities Commission, which also references return on book equity evidence. *See, e.g.*, Order No. 29505, Case No. IC-E-03-13 at 38 (Idaho Public Utilities Commission, May 25, 2004).
[7] David C. Parcell, *The Cost of Capital – A Practitioner's Guide*, Society of Utility and Regulatory Financial Analysts (2010) at 115-116.
[8] *Id.*

expressed in book value terms, a rate of return on book value, as is the case with Comparable Earnings, is highly meaningful."[9]

Q11. DOES MR. BAUDINO RECOGNIZE THE ECONOMIC PREMISE UNDERLYING THE EXPECTED EARNINGS APPROACH?

A11. Yes. The simple, but powerful concept underlying the expected earnings approach is that investors compare each investment alternative with the next best opportunity. As Mr. Baudino recognized, economists refer to the returns that an investor must forgo by not being invested in the next best alternative as "opportunity costs."[10] Mr. Baudino went on to explain that, "investor's opportunity cost is measured by what she or he could have invested in as the next best alternative."[11]

Q12. WHAT ROES ARE IMPLIED BY THE EXPECTED EARNINGS APPROACH FOR THE UTILITY PROXY GROUP?

A12. The year-end returns on common equity projected by Value Line Investment Survey ("Value Line") over its forecast horizon for the firms in the utility proxy group referenced by Mr. Baudino are shown on Exhibit AMM-21. As shown there, once adjusted to mid-year, reference to the expected earnings approach implies an average cost of equity for his proxy group of utilities of 10.6%. This expected book return is an "apples to apples" comparison to the 9.0% ROE recommendation supported by Mr. Baudino.

Q13. PLEASE EXPLAIN THE RATIONALE FOR THE ADJUSTMENT TO CONVERT YEAR-END RETURNS TO AVERAGE RETURNS WHEN APPLYING THIS METHOD.

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[9] Roger A. Morin, *New Regulatory Finance*, Pub. Util. Reports, Inc. (2006) at 395.
[10] Baudino Direct at 5.
[11] *Id.*

A13. The adjustment factor incorporated in my evaluation of expected returns is required because Value Line's reported returns are based on end-of-year book values. Since earnings are a flow over the year while book value is determined at a given point in time, the measurement of earnings and book value are distinct concepts. It is this fundamental difference between a flow (earnings) and point estimate (book value) that makes it necessary to adjust to mid-year in calculating the ROE. Given that book value will increase or decrease over the year, using year-end book value (as Value Line does) understates or overstates the average investment that corresponds to the flow of earnings. To address this concern, earnings must be matched with a corresponding representative measure of book value, or the resulting ROE will be distorted.

Q14. WHAT OTHER EVIDENCE INDICATES THAT MR. BAUDINO'S 9.0% ROE RECOMMENDATION FAILS TO MEET REGULATORY STANDARDS?

A14. As discussed in my Direct Testimony, required equity returns for firms in the competitive sector of the economy are also relevant in determining the appropriate return to be allowed for rate-setting purposes.[12] The idea that investors evaluate utilities against the returns available from other investment alternatives – including the low-risk companies in my Non-Utility Group – is a fundamental cornerstone of modern financial theory. Aside from this theoretical underpinning, any casual observer of stock market commentary and the investment media quickly comes to the realization that investors' choices are almost limitless. It follows that utilities must offer a return that can compete with other risk-comparable alternatives, or capital will simply go elsewhere.

[12] McKenzie Direct at 79-82.

In fact, returns in the competitive sector of the economy form the very foundation for utility ROEs because regulation purports to serve as a substitute for the actions of competitive markets. The Supreme Court has recognized that the degree of risk, not the nature of the business, is relevant in evaluating an allowed ROE for a utility.[13] The cost of capital is an opportunity cost based on the returns that investors could realize by putting their money in other alternatives, and the total capital invested in utility stocks is only the tip of the iceberg of total common stock investment. My reference to a low-risk group of non-utility companies is consistent with the guidance of the Supreme Court and Mr. Baudino's acknowledgement that "the task for the rate of return analyst is to estimate a return that is equal to the return being offered by other risk-comparable firms."[14]

Q15. WHAT ARE THE RESULTS OF YOUR ROE ANALYSIS FOR THE NON-UTILITY GROUP?

A15. As shown on Exhibit AMM-21, page 3, the average ROEs for the Non-Utility group range from 9.5% to 10.4%. The average of this range is 9.8%.

Q16. WHAT DO THESE BENCHMARKS YOU DISCUSS IMPLY WITH RESPECT TO MR. BAUDINO'S ROE RECOMMENDATION?

A16. As set forth above, objective consideration of regulatory standards and alternative benchmarks demonstrate that the ROE supported by Mr. Baudino is too low and violates the economic and regulatory standards underlying a fair ROE

Q17. WHAT OTHER PITFALLS ARE ASSOCIATED WITH AN ROE THAT FALLS BELOW THOSE AUTHORIZED FOR OTHER COMPARABLE COMPANIES?

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[13] *Fed. Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 591 (1944).
[14] Baudino Direct at 5-6.

A17. Adopting an ROE for the Company that is well below the ROEs for comparable utilities could lead investors to view the Commission's regulatory framework as unsupportive, an outcome that would undermine investors' willingness to support future capital availability for investment in Kentucky. Security analysts study regulatory orders in order to advise investors where to invest their money. Moody's Investors Service ("Moody's") noted that, "[f]undamentally, the regulatory environment is the most important driver of our outlook."[15] Similarly, Standard & Poor' ("S&P") concluded that "[t]he regulatory framework/regime's influence is of critical importance when assessing regulated utilities' credit risk because it defines the environment in which a utility operates and has a significant bearing on a utility's financial performance."[16] Value Line summarizes these sentiments:

> As we often point out, the most important factor in any utility's success, whether it provides electricity, gas, or water, is the regulatory climate in which it operates. Harsh regulatory conditions can make it nearly impossible for the best run utilities to earn a reasonable return on their investment.[17]

If Commission actions instill confidence that the regulatory environment is supportive, investors will provide the necessary capital, even in times of turmoil in the financial markets. In evaluating the Company's ROE in this case, the Commission has an opportunity to show that it recognizes the importance of continuity and a balanced regulatory regime.

Q18. DO CUSTOMERS BENEFIT WHEN INVESTORS HAVE CONFIDENCE THAT THE REGULATORY ENVIRONMENT IS STABLE AND CONSTRUCTIVE?

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[15] Moody's Investors Service, *Regulation Will Keep Cash Flow Stable As Major Tax Break Ends*, Industry Outlook (Feb. 19, 2014).
[16] Standard & Poor's Corporation, *Key Credit Factors For The Regulated Utilities Industry*, RatingsDirect (Nov. 19, 2013).
[17] Value Line Investment Survey, *Water Utility Industry*, January 13, 2017, p. 1780.

A18. Yes. When investors are confident that a utility has supportive regulation, they will make funds available on more reasonable terms, and even in times of turmoil in the financial markets. As noted above, regulatory signals are a primary driver of investors' risk assessment for utilities, and changing course from the path of financial strength would be extremely short-sighted. Customers and the service area economy enjoy the benefits that come from ensuring that the utility has the financial wherewithal to take whatever actions are required to ensure reliable service.

Mr. Baudino's recommended ROE is materially lower than the norms established for other utilities and would be viewed negatively by investors. Given the potential for regulatory lag, an ROE at the very bottom of the range of reasonableness would also undercut Kentucky Power's opportunity to earn a return that meets investors' requirements. These outcomes would violate regulatory standards and undermine the Company's ability to attract capital.

C. Implications of Current Capital Market Conditions

Q19. DOES MR. BAUDINO RECOGNIZE THE RECENT DISLOCATIONS THAT HAVE CHARACTERIZED THE ECONOMY AND CAPITAL MARKETS AS A RESULT OF COVID-19?

A19. Yes. Mr. Baudino comments on the turmoil and uncertainty experienced since the onset of the pandemic.[18] As his testimony describes, the threat posed by the coronavirus pandemic has led to extreme volatility in the capital markets as investors dramatically revise their risk perceptions and return requirements in the face of the severe disruptions to commerce and the world economy. Mr. Baudino

[18] Baudino Direct at 7-14.

concluded that, "I certainly agree with Mr. McKenzie that uncertainty and associated risk is greater not than it was prior to March 2020."[19]

Q20. HAVE UTILITIES AND THEIR INVESTORS FACED SIMILAR INSTABILITY?

A20. Yes. I discuss this topic in my direct testimony.[20] As of March 23, 2020, the Dow Jones Utility Average ("DJUA") had fallen approximately 36% from the previous high reached on February 18, 2020, demonstrating the fact that regulated utilities and their investors are not immune from the impact of financial market turmoil. As with the broader market, utility stock prices have recovered from these lows,[21] but the pronounced selloff and heightened volatility evidences a significant upward revision in investors' perceptions of risk.

Q21. CAN YOU SUMMARIZE THE FEDERAL RESERVE RESPONSE TO THE ECONOMIC THREAT POSED BY THE CORONAVIRUS PANDEMIC?

A21. I cover much of this area in my direct testimony.[22] The Federal Reserve has lowered its policy rate to close to zero to support economic activity, stabilize markets and bolster the flow of credit to households, businesses, and communities. In addition, they have implemented a broad range of unprecedented programs designed to support financial market liquidity and economic stability.

The Federal Reserve's asset holdings continue to exceed $7 trillion, which is an all-time high, and the resulting effect on capital market conditions has likely never been more pronounced. While the Federal Reserve's aggressive monetary stimulus may help to ensure market liquidity and support the economy, these

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[19] *Id.* at 38.
[20] McKenzie Direct at 19-37.
[21] As of September 30, 2020, the DJUA remained 15% below the high reached in February 2020.
[22] McKenzie Direct at 19-37.

actions also support financial asset prices, which in turn place artificial downward pressure on bond yields.

Q22. MR. BAUDINO ACKNOWLEDGES THE RECENT DECLINES IN YIELDS FOR U.S. TREASURY SECURITIES.[23] IS THIS THE PROPER FOCUS?

A22. No. He incorrectly equates trends in Treasury security yields with expected changes in the Company's cost of equity. While Treasury bond yields provide one indicator of capital costs, they do not serve as a direct guide to the magnitude—or even direction—for changes in the cost of equity for utilities.

For example, during times of heightened uncertainty and risk, investors may prefer the relative safety of U.S. government bonds, which can lead to a significant fall in Treasury bond yields at the same time that required returns on common stocks are increasing. Treasury bond yields may also be disproportionally impacted by monetary policies, such as quantitative easing ("QE"), designed with the express intent of artificially suppressing bond yields. The Federal Energy Regulatory Commission ("FERC") has recognized that movements in Treasury bond yields do not provide a reliable guide to changes in required returns for utilities, concluding that, "adjusting ROEs based on changes in U.S. Treasury bond yields may not produce a rational result, as both the magnitude and direction of the correlation may be inaccurate."[24]

Q23. DOES MR. BAUDINO'S EVIDENCE SUPPORT YOUR ARGUMENT THAT RISKS OF UTILITY COMMON STOCKS HAVE INCREASED?

A23. Yes. Mr. Baudino presents a comparison of beta values for the companies in his proxy group from early 2020 (preceding COVID-19) to when his direct testimony

[23] Baudino Direct at 38-39.
[24] *Coakley v. Bangor Hydro-Elec.*, 147 FERC ¶ 61,234 at P 159 (2014).

was recently filed.[25] This data shows that the average beta for the proxy group increased by 63%. He adds that "Three companies now have betas at or near 1.0, suggesting that they are now as risky as the overall stock market."[26]

Q24. MR. BAUDINO ARGUES THAT THE SHARP INCREASE IN BETAS IS A "SHORT-TERM PHENOMENON" AND WOULD NOT ADVISE "PLACING SIGNIFICANT RELIANCE ON CURRENT BETAS AT THIS TIME."[27] IS THIS A CONSISTENT APPROACH TO CHANGES IN CAPITAL MARKET CONDITIONS BROUGHT ON BY COVID-19?

A24. No. Later in his testimony, when referencing current low interest rates, Mr. Baudino states that "one should not abandon current interest rates altogether, as they represent current investor risk/return requirements for debt instruments, including Treasury and utility debt."[28] Mr. Baudino cannot have it both ways: he cannot ignore financial market data that points to increased ROEs (*i.e.*, higher betas) while embracing data that might lead to the opposite result. This "cherry picking" approach highlights the downward biases in his ROE estimation process.

Q25. IS THERE ANY MERIT TO MR. BAUDINO'S CONTENTION THAT IT WOULD BE UNREASONABLE TO RELY ON CURRENT BETA VALUES TO APPLY THE CAPM?

A25. No. Mr. Baudino's subjective and unsupported arguments on this issue are incorrect and should be given no weight. The relative price behavior of utility stocks versus the broader market reflects the actual valuation decisions of investors and there is no reason to ignore the implications of this data in applying the CAPM. Value Line's beta values are based on data over a five year period

[25] Baudino Direct at 33.
[26] *Id.*
[27] *Id.* at 34.
[28] *Id.* at 38.

applied using a consistent methodology, and Mr. Baudino presents no evidence to support a finding that this data is inaccurate.

Similarly, the fact that beta values for utilities were lower before the COVID-19 pandemic is irrelevant in the context of the CAPM. Setting aside the very real possibility that investors might reasonably anticipate a recurrence of the current health crisis, the relevance of Value Line's published beta values is not dependent on the assumption that risks affecting common stocks remain consistent with historical relationships. Rather, it is how investors incorporate information into their valuation decisions and ultimately, stock prices that determines risk in the context of modern capital market theory. Contrary to Mr. Baudino's claim that price movements in response to the coronavirus pandemic are somehow less than "reliable," they form the very foundation of this approach. The only risk at issue in applying the CAPM is the systematic risk reflected in a stock's price movements relative to the market as a whole, as measured by beta.

Mr. Baudino's suggestion that investors' recent actions can be ignored in favor of "prior history" is equally misguided. Ultimately, such suggestions devolve into highly subjective arguments regarding what time period might be considered "atypical" and what might be more representative. The reality is that the "true", forward-looking beta is unobservable and it is impossible to ascertain how investors will react to future information when valuing utility common stocks. That said, recent price movements leading to an increase in utility beta values reflect actual valuation decisions in the market and there is no reason to conclude that this information would not be considered by investors when forming their future expectations.

II. RESPONSE TO MR. BAUDINO

Q26. HOW DOES MR. BAUDINO ARRIVE AT HIS RECOMMENDED COST OF EQUITY?

A26. Mr. Baudino recommends an ROE range of 8.93% - 9.25% based exclusively on his application of the constant growth DCF model. He supports Mr. Kollen's ROE recommendation of 9.0% because it falls within his proposed range. While Mr. Baudino includes a CAPM analysis, he elects not to incorporate the results directly in his recommendation.[29] Mr. Baudino applies these methods to the same proxy group I do, but for two utilities that he excludes due to issues that I will discuss later in this testimony.

Q27. WHAT IS YOUR ASSESSMENT OF MR. BAUDINO'S ROE TESTIMONY AND RECOMMENDATION?

A27. Mr. Baudino's recommendation is not realistic. Several specific factors detract from his analysis. First and foremost, Mr. Baudino fails to apply sufficient checks of reasonableness to test his DCF results. His CAPM approach is significantly flawed and he ignores other accepted benchmarks such as the utility risk premium, expected earnings, and ECAPM methodologies, or a review of required returns for non-utility companies. Had Mr. Baudino employed these other approaches, he would have seen that his DCF-based result is not reasonable.

Q28. WHY IS IT CRITICAL TO CONSIDER THE RESULTS OF MULTIPLE APPROACHES WHEN EVALUATING A FAIR ROE FOR THE COMPANY?

A28. As I discuss in my direct testimony,[30] it customary to consider the results of multiple approaches when evaluating a just and reasonable ROE. It is widely recognized that no single method can be regarded as failsafe; with all approaches

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[29] *Id.* at 3.
[30] McKenzie Direct at 45-47.

having advantages and shortcomings. Consideration of the results of alternative approaches reduces the potential for error associated with any single quantitative method. The use of multiple cost of equity methods helps mitigate the impact of any temporary market anomalies that may be present in the market data of one company at a particular time. There is also a higher likelihood that random errors from multiple estimates will be offsetting and result in smaller cumulative error than random error from a single estimate.

Q29. MR. BAUDINO CRITICIZES THE CAPM BECAUSE "A CONSIDERABLE AMOUNT OF JUDGEMENT MUST BE EMPLOYED IN DETERMINING THE MARKET RETURN AND EXPECTED RISK PREMIUM ELEMENTS OF THE CAPM EQUATION."[31] IS THIS A VALID REASON FOR RELYING SOLELY ON THE DCF METHOD FOR SETTING THE ROE?

A29. No. Analytical methodologies such as the DCF model are inherently abstractions of reality. Underlying DCF theory requires any number of assumptions, most of which differ considerably from the situation that confronts actual investors in the capital markets.[32] Furthermore, as the submissions in this proceeding make clear, virtually every element of the DCF model is disputed. The CAPM approach is no different than the DCF model in these important aspects and is a valuable tool in the ROE estimation process. The CAPM, and other methods, are relied on by investors in making their investment decisions and have a rightful place in the regulatory process.

Q30. DO YOU HAVE ANY COMMENTS REGARDING MR. BAUDINO'S PROXY GROUP?

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[31] Baudino Direct at 29.

[32] These requirements include a flat yield curve; a constant growth rate; a constant P/E ratio; a constant dividend payout ratio; no stock issuances or purchases; dividends, earnings, book value, and stock price all grow at the same rate; and all of these conditions hold to infinity.

A30. Mr. Baudino accepts my proxy group with the exception of two companies. He eliminates Dominion Energy because they have announced a dividend reduction for the fourth quarter of 2020. He also excludes PPL Corp. because it has announced its intention to divest itself of its United Kingdom electric operations, which comprise a significant portion of its overall business. Both of these events have occurred since I filed my direct testimony, and they have the potential of compromising certain inputs to the ROE estimation models. For these reasons, I do not challenge Mr. Baudino's decision to exclude these two companies from the proxy group and I agree with the 21 company group that results.

A. Discounted Cash Flow Model

Q31. WHAT ARE THE SPECIFIC DEFECTS THAT YOU HAVE IDENTIFIED IN MR. BAUDINO'S DCF ANALYSIS?

A31. While Mr. Baudino's application of the DCF model is fairly straightforward, there are problems with his approach. First, he includes growth rates in dividends per share ("DPS"), which are not likely to provide a meaningful guide to investors' current growth expectations. Second, Mr. Baudino averages all of the individual growth rates for this proxy group firms and computes a single DCF estimate for each growth rate source. This approach masks the presence of extreme data and biases his results downward.

Q32. MR. BAUDINO CONSIDERS GROWTH RATES IN DPS IN APPLYING THE DCF MODEL. DO YOU AGREE THAT THIS IS WHAT INVESTORS ARE MOST LIKELY TO CONSIDER?

A32. No. As documented in my direct testimony, future trends in earnings per share ("EPS"), which provide the source for future dividends and ultimately support share prices, play a pivotal role in determining investors' long-term growth expectations. The continued success of investment services such as IBES,[33] Value Line, and Zacks Investment Research ("Zacks"), and the fact that projected growth rates from such sources are widely referenced, provides strong evidence that investors give considerable weight to analysts' earnings projections in forming their expectations for future growth. The importance of earnings in evaluating investors' expectations and requirements is well accepted in the investment community, and surveys of analytical techniques relied on by professional analysts indicate that growth in EPS is far more influential than trends in DPS. As explained in *New Regulatory Finance*:

> Because of the dominance of institutional investors and their influence on individual investors, analysts' forecasts of long-run growth rates provide a sound basis for estimating required returns. Financial analysts exert a strong influence on the expectations of many investors who do not possess the resources to make their own forecasts, that is, they are a cause of *g* [growth].[34]

The availability of projected EPS growth rates also is key to investors relying upon this measure as compared to future trends in DPS. Apart from Value Line, investment advisory services do not generally publish comprehensive DPS growth projections, and this scarcity of dividend growth rates relative to the abundance of EPS forecasts attests to their relative influence. In fact, Mr. Baudino admits that "Value Line is the only source of which I am aware that forecasts dividend growth."[35]

The fact that analyst EPS growth estimates are routinely referenced in the financial media and in investment advisory publications implies that investors use them as a primary basis for their expectations. As observed in *New Regulatory Finance*:

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[33] Formerly I/B/E/S International, Inc., IBES growth rates are now compiled and published by Refinitiv.
[34] Roger A. Morin, *New Regulatory Finance*, Pub. Util. Reports, Inc. (2006) at 298.
[35] Baudino Direct at 24.

> The sheer volume of earnings forecasts available from the investment community relative to the scarcity of dividend forecasts attests to their importance. The fact that these investment information providers focus on growth in earnings rather than growth in dividends indicates that the investment community regards earnings growth as a superior indicator of future long-term growth. Surveys of analytical techniques actually used by analysts reveal the dominance of earnings and conclude that earnings are considered far more important than dividends.[36]

While I do not rely solely on EPS projections in applying the DCF model,[37] my evaluation clearly supports greater reliance on EPS growth rate projections than other alternatives. Similarly, my Direct Testimony documents the Commission's preference for relying on analysts' growth forecasts, which is supported by the findings of other regulatory agencies.[38]

Growth rates in DPS are not likely to provide a meaningful guide to investors' current growth expectations. The importance of earnings in evaluating investors' expectations and requirements is well accepted in the investment community, and surveys of analytical techniques relied on by professional analysts indicate that growth in EPS is far more influential than trends in DPS.

Q33. ARE THERE OTHER PROBLEMS WITH MR. BAUDINO'S DCF ANALYSIS?

A33. Yes. Mr. Baudino's DCF analyses is flawed by his decision to average all individual growth rates across the proxy group and then compute a single DCF estimate for each growth rate source. Each growth rate represents a stand-alone estimate of investors' future expectations, and each value should be evaluated on its own merits. The fact that an average of several growth rates might produce a DCF estimate that could be considered reasonable does not absolve the need to evaluate each underlying growth rate separately.

[36] Roger A. Morin, *New Regulatory Finance*, Pub. Util. Reports, Inc. (2006) at 302-303.
[37] As discussed in my direct testimony, I also examined the "br+sv", sustainable growth rates for the companies in my proxy groups. McKenzie Direct at 54-55.
[38] McKenzie Direct at 52-53.

For example, consider a utility with a dividend yield of 3.5% and three hypothetical growth estimates of 0.0%, 6.5%, and 14.0%. Under Mr. Baudino's method, the DCF estimate would be computed by adding the 6.8% average of the three individual growth rates to the dividend yield, resulting in a cost of equity estimate of 10.3%. The problem with this method is that it disguises the fact that two of the underlying growth rates—0.0% and 14.0%—do not provide a meaningful guide to investors' expectations. Rather than averaging the good with the bad, each implied cost of equity estimate (in this example, 3.5%, 10.0%, and 17.5%) should be evaluated on a stand-alone basis.[39] Mr. Baudino simply calculates the average of the individual growth rates with no consideration for the reasonableness of the underlying data. Because Mr. Baudino failed to perform this essential step, his DCF analysis included individual growth rates that do not reflect investors' expectations. In the case of Mr. Baudino's DCF application, this resulted in results that are biased downward.

Q34. CAN YOU SHOW THE DOWNWARD BIAS IN MR. BAUDINO'S CONSTANT GROWTH ANALYSIS?

A34. Yes. For example, Mr. Baudino reports an IBES growth rate from *Yahoo! Finance* of 1.20% for Public Service Enterprise Group.[40] Combining this growth rate with its corresponding dividend yield of 3.85% results in a cost of equity estimate of 5.05%. Similarly, combining Consolidated Edison's Zacks growth rate of 2.00% with its dividend yield of 4.07% produces an ROE estimate of 6.07%. These implied costs of equity are less than any meaningful threshold. As a result, these illogical growth measures should have been removed from Mr. Baudino's constant growth DCF analysis.

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[39] The implied cost of equity estimates are calculated as the sum of the dividend yield (3.5%) and the respective growth rates (0.0%, 6.5%, and 14.0%).

[40] Exhibit RAB-4 at 1.

Q35. MR. BAUDINO SUBSTITUTES A ZACKS GROWTH RATE FOR THE IBES RATE FOR EXELON CORP. DO YOU AGREE WITH THIS ADJUSTMENT?

A35. No. Mr. Baudino makes this modification because the IBES growth rate is negative. He says that "negative growth rates cannot be expected to continue in perpetuity and so should be excluded from the proxy group constant growth DCF analysis."[41] I agree with this principal. However, rather than substitute a growth rate from an entirely difference source, Mr. Baudino should have simply excluded Exelon's IBES growth rate as "NMF," or "no meaningful figure." Furthermore, since the Zacks growth rate that Mr. Baudino uses as a substitute is less than the average growth rate for Exelon,[42] this has the effect of lowering its average growth rate further. This maneuver adds to the downward bias in Mr. Baudino's DCF approach.

Q36. MR. BAUDINO'S DCF "METHOD 2" UTILIZES MEDIAN GROWTH RATES TO FORMULATE DCF RESULTS.[43] DOES A REFERENCE TO THE MEDIAN IMPROVE HIS DCF ANALYSIS?

A36. No. The median is simply the observation with an equal number of data values above and below. For odd-numbered samples, the median relies on only a single number, *e.g.*, the fifth number in a nine-number set. I believe that each ROE result represents a stand-alone estimate of investors' future expectations, and each value should be evaluated on its own merits. The median does not really consider the results of analysis at all—it is simply a number that splits the distribution of observations into two equal halves. The fact that a median of several outcomes might produce a DCF estimate that could be considered reasonable does not

[41] Baudino Direct at 25.
[42] The rate substituted for Exelon's negative earnings growth rate by Mr. Baudino is 4.0% (Exhibit RAB-4 at 1).
[43] Baudino Direct at 25.

absolve the need to evaluate each underlying return separately. Without considering the underlying data, and by including ROE estimates that do not reflect investor expectations, Mr. Baudino's median approach biases his results downward.

B. Capital Asset Pricing Model

Q37. WHAT IS THE MOST TROUBLING ASPECT OF MR. BAUDINO'S CAPM ANALYSIS?

A37. One of Mr. Baudino's CAPM approaches produces outcomes that are so low they should be rejected outright. Results from his historical market risk premium model range from 6.73% to 8.77%.[44] These are far too low to be considered legitimate ROE estimates.

Q38. WHY IS THIS PORTION OF MR. BAUDINO'S CAPM ANALYSIS FATALLY FLAWED?

A38. The CAPM is an *ex-ante*, or forward-looking model based on expectations of the future. As a result, in order to produce a meaningful estimate of investors' required rate of return, the CAPM must be applied using data that reflect the expectations of actual investors in the market. Mr. Baudino recognizes that:

> **Return on equity analysis is a forward-looking process.** Five-year or ten-year historical growth rates may not accurately represent investor expectations for future dividend growth. Analysts' forecasts for earnings and dividend growth provide better proxies for the expected growth component in the DCF model than historical growth rates. Analysts' forecasts are also widely available to investors and one can reasonably assume that they influence investor expectations.[45]

The primacy of current expectations was recognized by Morningstar, one of the sources relied on by Mr. Baudino to apply the CAPM:

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[44] *Id.*, Table 3, at 35.
[45] *Id.* at 24 (emphasis added).

> **The cost of capital is always an expectational or forward-looking concept.** While the past performance of an investment and other historical information can be good guides and are often used to estimate the required rate of return on capital, **the expectations of future events are the only factors that actually determine cost of capital**.[46]

Nevertheless, at least part of Mr. Baudino's application of the CAPM method is based on *historical* – not projected – rates of return (Exhibit RAB-6). Because Mr. Baudino's backward-looking analysis ignores the returns investors are currently requiring in the capital markets, the resulting CAPM estimates fall woefully short of investors' current required rate of return.

Q39. IS THERE GOOD REASON TO ENTIRELY DISREGARD THE RESULTS OF HISTORICAL CAPM ANALYSES SUCH AS THOSE PRESENTED BY MR. BAUDINO?

A39. Yes. Applying the CAPM is complicated by the impact of the Federal Reserve policies on investors' risk perceptions and required returns. As the Staff of the Florida Public Service Commission concluded regarding historical applications of the CAPM:

> [R]ecognizing the impact the Federal Government's unprecedented intervention in the capital markets has had on the yields on long-term Treasury bonds, staff believes models that relate the investor-required return on equity to the yield on government securities, such as the CAPM approach, produce less reliable estimates of the ROE at this time.[47]

And while the backward-looking approach used by Mr. Baudino incorrectly assumes that investors' assessment of the relative risk differences, and their required risk premium, between Treasury bonds and common stocks is constant and equal to some historical average, FERC determined that CAPM methodologies based on historical data were suspect because whatever historical

[46] Morningstar, *Ibbotson SBBI, 2013 Valuation Yearbook* at 21 (emphasis added).
[47] *Staff Recommendation for Docket No. 080677-E1 - Petition for increase in rates by Florida Power & Light Company*, Docket No. 080677-E1, at 280 (Dec. 23, 2009).

relationships existed between debt and equity securities may no longer hold.[48] FERC concluded that historical risk premiums are downward biased given recent trends of low yields for Treasury bonds.[49]

Similarly, the Indiana Utility Regulatory Commission has previously concluded that:

> Relying on historic market returns introduces some highly questionable assumptions, which must be taken on faith. Specificlaly [sic], one must assume that marketplace returns experienced historically are what investors were expecting to receive and continue to guide investor expectations today. It also assumes that asset relationships prevailing over the past 62 years continue today unchanged.[50]

As a result, there is every indication that the historical CAPM approach fails to fully reflect the risk perceptions of real-world investors in today's capital markets, and the result should be ignored.

Q40. IS THERE EVIDENCE THAT THE HISTORICAL ANALYSES REFERENCED BY MR. BAUDINO DO NOT REFLECT INVESTORS' EXPECTATIONS?

A40. Yes. The historical equity risk premium findings reported by Mr. Baudino do not make economic sense and contradict his own testimony. For example, Mr. Baudino's Exhibit RAB-6 reveals historical market equity risk premiums of 6.14% and 7.20%. But combining these market equity risk premiums with Mr. Baudino's risk-free rate based on 30-year Treasury bond yield of 1.38%, results in an indicated cost of equity range for the <u>market as a whole</u> of 7.52% to 8.58%, which is less than his ROE recommendation for Kentucky Power in this case.

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[48] *See Orange & Rockland Utils., Inc.*, 40 FERC ¶ 63,053 at 65,208-09 (1987), *aff'd*, Opinion No. 314, 44 FERC ¶ 61,253 at 65,208 (2008).
[49] *See New York Independent System Operator, Inc.*, 146 FERC ¶ 61,043 at P 105 (2014).
[50] Indiana Utility Regulatory Commission, *Indiana Michigan Power Co.*, Cause No. 38728 (Aug. 24, 1990).

Meanwhile, after noting that beta is the relevant measure of investment risk under modern capital market theory, Mr. Baudino's comparison of beta values (Exhibit RAB-5) indicates that investors' required return on the market as a whole should exceed the cost of equity for electric utilities.[51] Based on Mr. Baudino's own logic, it follows that a market rate of return that does not significantly exceed his own downward biased ROE recommendation has no relation to the current expectations of real-world investors. The fact that much of his CAPM analysis violates the risk-return tradeoff that is fundamental to financial theory clearly illustrates the frailty of Mr. Baudino's analyses.

Q41. WHAT ELSE IS WRONG WITH MR. BAUDINO'S CAPM ANALYSIS?

A41. Mr. Baudino attempts to develop a forecasted market return, which is a laudable goal. However, instead of simply relying on Value Line earnings forecasts, he introduces book value growth into the process. As I describe above, growth in EPS is the most influential driver of investors' long-term expectations. Adding book value growth only serves to depress his market return estimate, especially given that the earnings growth rate is 9.0% and the book value growth rate is 6.5%.[52] If Mr. Baudino had left out the book value component, his market return projection would have been more reasonable, at 10.12%.[53]

Q42. IS THERE ANY MERIT TO MR. BAUDINO'S ARGUMENT (AT 43-44) THAT YOUR ANALYSIS OF THE MARKET RATE OF RETURN SHOULD NOT HAVE BEEN LIMITED SOLELY TO THE DIVIDEND PAYING FIRMS IN THE S&P 500?

A42. No. As Mr. Baudino recognized (at 19), under the constant growth form of the DCF model, investors' required rate of return is computed as the sum of the

[51] Baudino Direct at 26-27.
[52] Exhibit RAB-5, page 2.
[53] *Id.* Earnings growth of 9.00% plus the average dividend yield of 1.12% is 10.12%.

dividend yield over the coming year plus investors' long-term growth expectations. Because the dividend yield is a key component in applying the DCF model, its usefulness is hampered for firms that do not pay common dividends. Accordingly, my DCF analysis of the market rate of return properly focused on the dividend paying firms included in the S&P 500.

Meanwhile, Mr. Baudino (at 29-30) predicated his DCF analysis of the market rate of return on the companies followed by Value Line. Of the 1,700 U.S. firms in Value Line, approximately 700 do not pay common dividends. In other words, over one-third of the companies that underpin Mr. Baudino's DCF analysis do not have the data necessary to implement this approach. Further, many of these firms are relatively small and lack a meaningful operating history. As a result, there is also greater uncertainty associated with estimating the future growth expectations that are central to the application of the DCF method. Taken together, these factors impugn the reliability of Mr. Baudino's market risk premium and confirm my decision to restrict the analysis to the established, dividend paying firms in the S&P 500.

Q43. DO THE ARGUMENTS ADVANCED BY MR. BAUDINO UNDERMINE THE NEED FOR A SIZE ADJUSTMENT AS PART OF THE CAPM AND ECAPM ANALYSES?

A43. No. Mr. Baudino simply observes that the average beta associated with the lower size deciles examined by Duff & Phelps is greater than the average of his proxy group.[54] While I do not dispute the observation, it has no relevance whatsoever to the implications of Duff & Phelps' findings regarding the impact of firm size. The fact that the average beta for smaller size deciles is greater than for 1.00 says nothing about the range of individual beta values underlying this average.

[54] Baudino Direct at 44.

Moreover, the size premiums are beta adjusted; meaning that the risk impact of beta values (whether higher or lower than Mr. Baudino's proxy group average) have been removed. While the size premiums reported by Duff & Phelps were not estimated on an industry-by-industry basis, this provides no basis to ignore this relationship in estimating the cost of equity for utilities. Utilities are included in the companies used by Duff & Phelps to quantify the size premium, and firm size has important practical implications with respect to the risks faced by investors in the utility industry. As Duff & Phelps concluded*:*

> Despite many criticisms of the size effect, it continues to be observed in data sources. Further, observation of the size effect is consistent with a modification of the pure CAPM. Studies have shown the limitations of beta as a sole measure of risk. The size premium is an empirically derived correction to the pure CAPM.[55]

Q44. MR. BAUDINO ARGUES THAT A CAPM/ECAPM SIZE ADJUSTMENT DOES NOT APPLY BECAUSE REGULATED COMPANIES ARE "ON AVERAGE QUITE DIFFERENT FROM THE GROUP OF COMPANIES INCLUDED IN THE DUFF AND PHELPS RESEARCH ON SIZE PREMIUM."[56] IS THIS A VALID CRITICISM?

A44. No. There is no credible basis to conclude that CAPM or ECAPM estimates for utilities are immune from the well-documented relationship between smaller size and higher realized rates of return. The size adjustment required in applying the CAPM and ECAPM is based on the finding that *after controlling for risk differences reflected in beta*, the CAPM overstates returns to companies with larger market capitalizations and understates returns for relatively smaller firms. Of course, there are any number of specific factors that distinguish a utility's risks from other firms in the non-regulated sector, just as there are important

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[55] Duff & Phelps, *2016 Valuation Handbook, Guide to Cost of Capital*, John Wiley & Sons (2016) at 4-27.
[56] Baudino at 44-45.

distinctions between the circumstances faced by airlines and drug manufacturers. But under the assumptions of modern capital market theory on which the CAPM rests, these considerations are reduced to a single risk measure—beta—which captures stock price volatility relative to the market.

Within the CAPM paradigm, the degree of regulation, the nature of competition in the industry, the competence of management, and every other firm-specific consideration is boiled down to a single question; namely, how much does the stock's price fluctuate in relation to the market as a whole? Beta is the measure of that variability, and research demonstrates that beta does not fully account for the impact of firm size. *Duff & Phelps*, which is a primary source underlying Mr. Baudino's CAPM applications, concluded that:

> Examination of market evidence shows that within the context of the CAPM, beta does not fully explain the difference between small company returns and large company returns. In other words, the *actual* (historical) excess return smaller companies earn tends to be greater than the excess return *predicted* by the CAPM for these companies. This 'premium over CAPM' is commonly known as a 'beta-adjusted size premium' or simply "size premium."[57]

Contradicting the incorrect inference Mr. Baudino draws regarding the relative risk of utilities, *Duff & Phelps* notes that its size premia "have been adjusted to remove the portion of excess return that is attributable to beta, leaving only the size effect's contribution to excess return."[58] In other words, the impact of risk differences between utilities and non-regulated firms is already accounted for and there is no justification to remove the size adjustment on this basis.

[57] Duff & Phelps, *2016 Valuation Handbook, Guide to Cost of Capital*, John Wiley & Sons (2016) at 8-1. Duff & Phelps now publishes the study of historical returns formerly compiled by Morningstar, and previously published by Ibbotson Associates.

[58] Duff & Phelps, 2017 *Valuation Handbook, U.S. Guide to Cost of Capital*, John Wiley & Sons (2017) at 2-10.

Q45. DOES REFERENCE TO THE IBBOTSON & CHEN OR DUFF & PHELPS HISTORICAL MARKET RISK PREMIUM DATA CITED BY MR. BAUDINO,[59] PROVIDE ANY MEANINGFUL CORROBORATION OR GUIDANCE AS TO INVESTORS' REQUIRED RATE OF RETURN?

A45. No. According to Mr. Baudino, this market risk premium data predicts that equity returns for the stock market as a whole will amount to 7.52% and 8.64%.[60] These figures fall below Mr. Baudino's ROE recommendation for the Company and below returns authorized for utilities by other state commissions. Considering that these market returns fall so far below ROEs for utility—which are viewed as less risky than the market as a whole—they are not relevant to the Commission's deliberations.

Q46. WHAT ARE THE RESULTS OF MR. BAUDINO'S CAPM ANALYSIS USING THE PROPER FORWARD-LOOKING APPROACH?

A46. As shown on Table 3 on page 35 of Mr. Baudino's testimony, his forward-looking CAPM methodology yields ROE estimates of 9.80% and 9.95%. It is no coincidence that these are the most reasonable of his CAPM outcomes; they are properly based on investor's forward-looking expectations, not historical data from 1926. In fact, these outcomes, approaching 10.0%, should have alerted Mr. Baudino to the unrealistic nature of his ROE analysis. ROE estimates of 8.61% - 8.75% are well below any meaningful level and Mr. Baudino's forward-looking CAPM outcomes prove this point.

C. Other ROE Issues

Q47. MR. BAUDINO ARGUES YOUR DCF ANALYSIS IS FLAWED BECAUSE YOU "APPLIED A TEST FOR EXCLUDING ROE RESULTS

[59] Baudino Direct at 31.

[60] Exhibit RAB-6. Using the current 30-year Treasury Yield data, the market return is 6.14% plus the risk-free rate of 1.38%, or 7.52%. Using the Duff & Phelps "normalized" risk-free rate, the market return is 6.14% plus 2.50%, or 8.64%.

THAT…WERE TOO LOW, BUT FAILED TO EXCLUDE OTHER RESULTS THAT ARE EXCESSIVELY HIGH."[61] IS THIS A VALID ARGUMENT?

A47. No. I evaluate low-end outliers against the observable returns available from long-term bonds. But the fact that there are numerous results that fail this test of reasonableness says nothing about the validity of estimates at the upper end of the range of results, and there is no basis to discard a corresponding number of values from the top of the range. While upper end cost of equity estimates on the order of 13.6% from my Exhibit AMM-4, page 3 may exceed expectations for most utilities, the remaining low-end estimates in the 7.0% range are assuredly far below investors' required rate of return. Taken together and considered along with the balance of the DCF estimates, these values provides a reasonable basis on which to evaluate investors' required rate of return. Mr. Baudino's attempt to recast my DCF analysis including all DCF results,[62] which retains ROE values of 1.8% and 5.6% is misleading and unjustified.

Q48. DOES MR. BAUDINO ADVANCE ANY CREDIBLE CRITICISM OF YOUR RISK PREMIUM APPROACH?

A48. No. Mr. Baudino's only observation is that the risk premium method is "imprecise."[63] Of course, this "criticism" applies equally to every model of investor behavior that is used to estimate required returns, including the DCF approach that formed the sole basis for Mr. Baudino's recommendation. The DCF method is only one theoretical approach to gain insight into the return investors require, which is unobservable. While the tautology of the DCF model boils this determination down to the familiar dividend yield and growth rate

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[61] Baudino Direct at 40-42.
[62] *Id.* at 41-42.
[63] *Id.* at 48.

components, this masks the underlying complexities that accompany any attempt to distill every facet of investors' expectations into a single growth estimate. Mr. Baudino's claim that the DCF is "far more reliable and accurate"[64] is unsubstantiated. While the DCF model is a recognized approach to estimating the cost of equity, it is not without shortcomings and does not otherwise eliminate the need to examine the results of other methods. As the Indiana Utility Regulatory Commission noted, for example:

> There are three principal reasons for our unwillingness to place a great deal of weight on the results of any DCF analysis. One is . . . the failure of the DCF model to conform to reality. The second is the undeniable fact that rarely if ever do two expert witnesses agree on the terms of a DCF equation for the same utility – for example, as we shall see in more detail below, projections of future dividend cash flow and anticipated price appreciation of the stock can vary widely. And, the third reason is that the unadjusted DCF result is almost always well below what any informed financial analysis would regard as defensible, and therefore require an upward adjustment based largely on the expert witness's judgment. In these circumstances, we find it difficult to regard the results of a DCF computation as any more than suggestive.[65]

Q49. HOW DO YOU RESPOND TO MR. BAUDINO'S DISCUSSION OF YOUR NON-UTILITY ANALYSIS?

A49. Mr. Baudino makes the statement that utilities "have protected markets, e.g., service territories, and may increase the prices they charge in the face of falling demand or loss of customers."[66] Based on this, Mr. Baudino summarily concludes, "Obviously, the non-utility companies face risks that a lower risk electric company like KPC does not face."[67] In fact, however, investors are quite aware that utilities are not guaranteed recovery of reasonable and necessary costs incurred to provide service and that there are many instances in which utilities are

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[64] *Id.*
[65] *Ind. Michigan Power Co.*, Cause No. 38728, 116 PUR4th, 1, 17-18 (IURC 8/24/1990).
[66] Baudino Direct at 51.
[67] *Id.*

unable to increase rates to fully recoup reasonable and necessary costs, resulting in an inability to earn the allowed ROE – and potentially, even bankruptcy. The simple observation that a firm operates in non-utility businesses says nothing at all about the overall investment risks perceived by investors, which is the very basis for a fair rate of return.

The cost of capital is an opportunity cost based on the returns that investors could realize by putting their money in other alternatives, which include all other securities available in the stock, bond, or money markets. Consistent with this view, Mr. Baudino notes the Supreme Court's economic standards and concluded that the fair rate of return on equity should be "comparable to the returns of other firms with similar risk structures."[68] Clearly the total capital invested in utility stocks is only the tip of the iceberg of total common stock investment and there are a plethora of other "investments of comparable risk" available to investors beyond those in the utility industry.

True enough, utilities are sheltered from competition, but they undertake other obligations and lose the ability to set their own prices and decide when to exit a market. The Supreme Court has recognized that it is the degree of risk, not the nature of the business, which is relevant in evaluating an allowed ROE for a utility.[69]

Q50. DOES OBJECTIVE EVIDENCE SUPPORT MR. BAUDINO'S RISK ARGUMENTS?

A50. No. The average corporate credit rating for the Non-Utility Group referenced in my direct testimony of "A-" is <u>higher</u> than the "BBB+" average for the Utility Group and the Company. This assessment is confirmed by the review of financial strength values and other objective indicators of investment risk presented in

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[68] *Id.* at 5.
[69] *Fed. Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 591 (1944).

Table AMM-9 to my direct testimony, which consider the impact of competition and market share and demonstrated that, if anything, the Non-Utility Group could be considered less risky in the minds of investors than the common stocks of the proxy group of utilities.

Q51. MR. BAUDINO SAYS THAT AN ADJUSTMENT TO ACCOUNT FOR FLOTATION COSTS IS NOT NECESSARY SINCE "FLOTATION COSTS ARE ALREADY ACCOUNTED FOR IN CURRENT STOCK PRICES."[70] IS THIS A VALID ASSUMPTION?

A51. No. Mr. Baudino's position is akin to arguing that it is not necessary to reflect the utility's entire reasonable and necessary O&M expense in revenue requirements because such actions would be "accounted for" in the stock price. Flotation costs are legitimate expenses and unless a discrete adjustment is made to recognize them, they will not be recovered in the rate setting process.

Q52. AG/KIUC'S 9.0% ROE RECOMMENDATION ORIGINATES FROM MR. KOLLEN. MR. KOLLEN POINTS TO SERVICE AREA ECONOMIC CONDITIONS AND POTENTIAL CUSTOMER IMPACTS AS CONSIDERATIONS WHEN ESTABLISHING A FAIR ROE.[71] HOW DO YOU RESPOND?

A52. First, it is important to note that the determination of the ROE is made by investors in the capital markets, and is not predicated on any notion of costs or savings to customers. The U.S. Supreme Court's regulatory standards embodied in the *Hope* and *Bluefield* decisions represent a balance between the interests of customers and investors, by setting forth the guidelines as to a fair ROE. Meanwhile, Mr. Kollen wrongly suggests that a lower ROE is *per se* in customers' benefit. This is not the case. While a downward-biased ROE may

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[70] Baudino Direct at 50.
[71] Kollen Direct at 44-46.

provide the illusion of customer "savings" in the form of a lower revenue requirement in the short-term, the long-term impact of an inadequate ROE can be injurious to customers and the Kentucky economy.

As discussed earlier, there is a very real connection between the ROE and the availability of capital, and Mr. Kollen ignores the negative impact that an inadequate ROE would have on investment. The ROE is the primary signal to investors, not only with respect to attracting new capital investment, but also in supporting existing utility operations. If the utility is unable to offer a competitive ROE, existing shareholders will suffer a capital loss as investors take advantage of other, more favorable opportunities, and the utility's stock price would fall. Moreover, as investors' confidence is undermined, the ability of utilities to access equity capital markets and expand investment will suffer. While the Company would undoubtedly continue to meet their service obligations to customers, a downward-biased ROE would send an unmistakable signal to the investment community as they consider whether to commit capital in Kentucky, and at what cost.

III. RESPONSE TO MR. OWEN

Q53. DOES MR. OWEN CONDUCT AN INDEPENDENT EVALUATION OF A FAIR ROE FOR KENTUCKY POWER?

A53. No. Mr. Owen does not conduct any analyses of the cost of equity. His testimony largely consists of citations to the U.S. Supreme Court's decisions in *Bluefield* and *Hope*, as well as presentation of selected data concerning previously authorized ROEs. Based on this limited review, Mr. Owen expresses his concern about the reasonableness of the Company's proposed ROE.[72]

[72] Owen Direct at 16-24.

Q54. DO YOU AGREE WITH MR. OWEN THAT ALLOWED ROEs PROVIDE ONE BENCHMARK WORTHY OF CONSIDERATION IN THE COMMISSION'S EVALUATION?

A54. Yes, I do. Importantly, however, such comparisons of allowed ROEs are only one consideration. While this data can be useful in the Commission's deliberations, it is not a substitute for the detailed analyses presented in my direct testimony and in my update here.

Q55. DOES THE DATA PRESENTED BY MR. OWEN CONFIRM YOUR CONCLUSION THAT AG/KIUC'S RECOMMENDATION IS TOO LOW?

A55. Yes. Mr. Owen cites an average of recent allowed ROEs for vertically integrated utilities of 9.67% and a median of 9.70%,[73] which confirms my earlier conclusion that the 9.0% ROE recommendation of AG/KIUC falls well below returns authorized for other utilities, and is insufficient to meet the requirements of regulatory standards.

Q56. FROM YOUR POSITION AS A REGULATORY FINANCIAL ANALYST, WHAT DO YOU MAKE OF MR. OWEN'S ADMONITION TO CONSIDER CUSTOMER IMPACTS WHEN ESTABLISHING A FAIR ROE?

A56. As discussed earlier in response to Mr. Kollen, the cost of attracting and retaining equity capital is a function of investor requirements, and while regulatory standards involve a balancing of the interests of customers and investors, ratepayer savings are not determinative when establishing the ROE. Mr. Owen's suggestion that reducing the Company's ROE is inherently beneficial to customers ignores the negative impact that would ultimately result from an inadequate ROE.

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[73] *Id.* at 21.

IV. UPDATE TO QUANTITATIVE ANALYSIS

Q57. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?

A57. In light of the significant changes in capital market conditions since my direct testimony was prepared, this section presents updated results for the quantitative approaches described in my direct testimony using current data.

Q58. DO THESE UPDATED QUANTITATIVE RESULTS LEAD YOU TO MODIFY THE PRINCIPAL CONCLUSIONS AND ROE RECOMMENDATION PRESENTED IN YOUR EARLIER FILED DIRECT TESTIMONY?

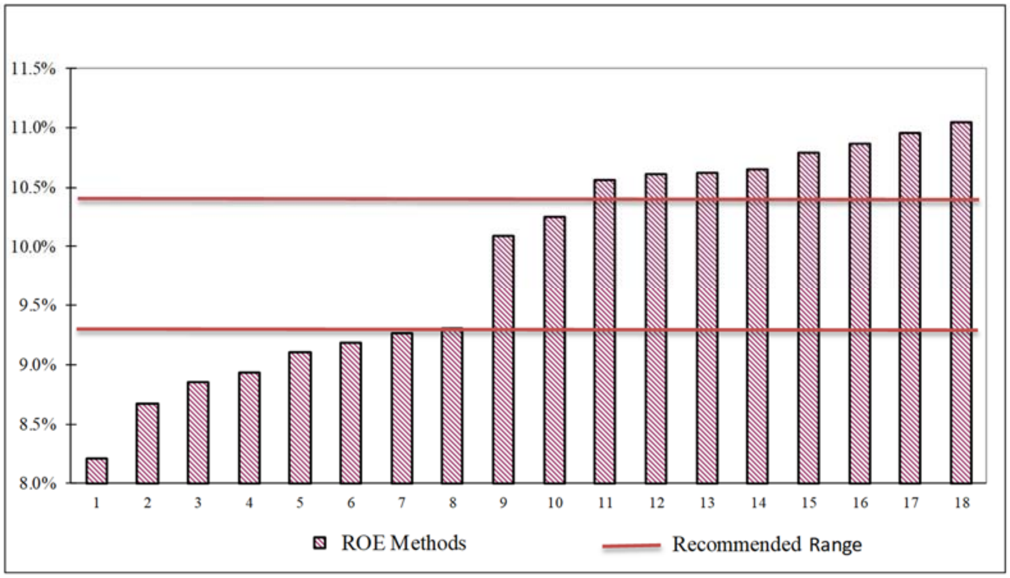
A58. No. The results of my updated analyses are presented in Exhibit AMM-14 and summarized in Table R-2, below:

TABLE R-2
SUMMARY OF UPDATED COST OF EQUITY ESTIMATES

	Average	Median	Midpoint
DCF			
Value Line	8.9%	8.7%	10.3%
IBES	9.1%	9.3%	8.9%
Zacks	9.3%	9.3%	9.2%
Internal br + sv	8.2%	8.0%	8.7%
Average	8.9%	8.8%	9.2%
CAPM			
Current Bond Yield	10.6%	10.3%	10.8%
Projected Bond Yield			
Average	10.6%	10.3%	10.8%
Empirical CAPM			
Current Bond Yield	10.9%	10.5%	11.1%
Projected Bond Yield			
Average	10.9%	10.5%	11.1%
Utility Risk Premium			
Current Bond Yields	9.3%	9.3%	9.3%
Projected Bond Yield			
Average	9.3%	9.3%	9.3%
Expected Earnings	10.6%	10.9%	10.6%
Indicated ROE	**10.0%**	**9.9%**	**10.2%**

These results are also presented in graphical form in Figure R-2, below:

FIGURE R-2
DISTRIBUTION OF COST OF EQUITY ESTIMATES



As illustrated above, an ROE range of approximately 9.3% to 10.4% (before a flotation cost adjustment) continues to reflect the center of the distribution, with the 10.0% ROE requested by Kentucky Power falling in the middle of the results.

Q59. IN APPLYING THE DCF MODEL, HOW DO YOU DETERMINE THE UPDATED DIVIDEND YIELDS FOR THE PROXY GROUP?

A59. Estimates of dividends to be paid by each of these utilities over the next twelve months, obtained from the October 2, 2020 edition of Value Line, serve as D_1. This annual dividend is then divided by a 30-day average stock price for each utility to arrive at the expected dividend yield. The updated dividends, stock prices, and resulting dividend yields for the firms in the Updated Utility Group[74] are presented on Exhibit AMM-15. As shown on the first page of this exhibit,

[74] The Updated Utility Group excludes Dominion Energy and PPL Corp. from the proxy group in my direct testimony, as discussed previously.

dividend yields for the firms in the Updated Utility Group average 3.7% (versus 3.9% in my direct testimony).

Q60. WHERE DO YOU REPORT THE REVISED DCF COST OF COMMON EQUITY ESTIMATES FOR THE UPDATED UTILITY GROUP?

A60. After combining the dividend yields and respective growth projections for each utility, the resulting cost of common equity estimates are shown on page 3 of Exhibit AMM-15.

Q61. WHAT ROE ESTIMATES ARE IMPLIED BY YOUR UPDATED DCF RESULTS?

A61. My updated application of the constant growth DCF model is shown on page 3 of Exhibit AMM-15 and the results are summarized in Table R-3, below:

TABLE R-3
DCF RESULTS – UPDATED UTILITY GROUP

	Cost of Equity	
Growth Rate	Average	Midpoint
Value Line	8.9%	10.3%
IBES	9.1%	8.9%
Zacks	9.3%	9.2%
br + sv	8.2%	8.7%

Q62. HOW DO YOU CALCULATE THE MARKET RISK PREMIUM IN YOUR UPDATE OF THE CAPM?

A62. I use the same approach described in my direct testimony, only updated to reflect current information. The yield for each dividend-paying firm in the S&P 500 is obtained from Value Line, and the growth rate is equal to the average of the earnings growth projections for each firm published by IBES, Zacks, and Value Line, with each firm's dividend yield and growth rate being weighted by its proportionate share of total market value. As shown on Exhibit AMM-17, based on the weighted average of the projections for the individual firms, current estimates imply an average growth rate over the next five years of 9.2%. Combining this average growth rate with a year-ahead dividend yield of 2.3% results in a current cost of common equity estimate for the market as a whole (R_m) of 11.6%.[75]

Q63. WHAT IS THE SOURCE OF THE BETA VALUES YOU USED TO APPLY THE CAPM?

A63. I continue to rely on beta values reported by Value Line.

Q64. WHAT IS THE IMPLIED ROE FOR THE UPDATED UTILITY GROUP USING THE CAPM APPROACH?

A64. As shown on page 1 of Exhibit AMM-17, after adjusting for the impact of firm size, the CAPM approach implies an average ROE for the Updated Utility Group of 10.6% (versus 8.0% in my direct testimony).

Consistent with my direct testimony, I also applied the CAPM based on updated forecasts of long-term Treasury bond yields developed based on projections published by Value Line, IHS Global Insight and Blue Chip for the years 2021-2025. As shown on page 2 of Exhibit AMM-17, incorporating a forecasted Treasury bond yield implies an average cost of equity estimate of 10.7% for the proxy Group (versus 8.4% in my direct testimony).

Q65. WHAT UPDATED COST OF EQUITY ESTIMATES ARE INDICATED BY THE ECAPM?

A65. My application of the ECAPM is based on the same forward-looking market rate of return, risk-free rates, and beta values discussed above in connection with the CAPM. As shown on page 1 Exhibit AMM-18, applying the forward-looking ECAPM approach to the firms in the Updated Utility Group using current bond yields results in an average cost of equity estimate of 10.9%.

[75] Any differences in the summation due to rounding.

As shown on page 2 of Exhibit AMM-18, applying the ECAPM using a forecasted Treasury bond yield for 2021-2025 implies an average cost of equity estimate of 11.0%.

Q66. WHAT IS THE UPDATED ROE IMPLIED BY YOUR APPLICATION OF THE RISK PREMIUM METHOD?

A66. As illustrated on page 1 of Exhibit AMM-19 with an average yield on average public utility bonds for the six-months ending September 2020 of 3.01%, this implies a current equity risk premium of 5.90% for electric utilities. Adding this equity risk premium to the average yield on Baa utility bonds corresponding to the Company implies a current ROE of 9.27%.

Q67. WHAT IS THE RESULT OF THE RISK PREMIUM APPROACH AFTER INCORPORATING FORECASTED BOND YIELDS?

A67. As shown on page 2 of Exhibit AMM-19, incorporating a forecasted yield for 2021-2025 and adjusting for changes in interest rates since the study period implies an equity risk premium of 5.31% for electric utilities, which is less than current equity risk premiums. Adding this equity risk premium to the implied average yield on triple-B public utility bonds for 2021-2025 of 4.79%, results in an implied cost of equity of 10.10%.

Q68. MR. BAUDINO CRITICIZES YOUR RELIANCE ON FORECASTED INTEREST RATES.[76] HOW DO YOU RESPOND?

A68. I cover this issue in my direct testimony.[77] While the projections of securities analysts may be proven optimistic or pessimistic in hindsight, this is irrelevant in assessing the expected changes in interest rates that investors have incorporated

[76] Baudino Direct at 39.
[77] McKenzie Direct at 52.

into their equity cost expectations, and any bias in analysts' forecasts – whether pessimistic or optimistic – is irrelevant if investors share analysts' views.[78]

Q69. WHAT ROES ARE INDICATED FOR KENTUCKY POWER BASED ON THE EXPECTED EARNINGS APPROACH?

A69. For the firms in the updated proxy group, year-end returns on common equity projected by Value Line over its forecast horizon are shown on Exhibit AMM-20. As shown there, Value Line's current projections suggest an average ROE of 10.6%.

Q70. WHAT ARE THE UPDATED RESULTS OF YOUR DCF ANALYSIS FOR THE NON-UTILITY GROUP?

A70. The updated results of my DCF analysis for the Non-Utility Group are presented in Exhibit AMM-21. As summarized in Table R-4, below, after eliminating illogical values, application of the constant growth DCF model results in the following cost of equity estimates:

TABLE R-4
DCF RESULTS – NON-UTILITY GROUP

	Cost of Equity	
Growth Rate	**Average**	**Midpoint**
Value Line	10.4%	10.4%
IBES	9.5%	9.9%
Zacks	9.6%	9.9%

These results provide additional confirmation that a 10.0% ROE for Kentucky Power is reasonable.

Q71. DOES THIS CONCLUDE YOUR PRE-FILED REBUTTAL TESTIMONY?

A71. Yes, it does.

[78] Excluding all results based on projected bond yields would result in indicated ROEs of 10.0% (average), 9.9% (median), and 10.2% (midpoint) under the presentation shown in Table R-2. This would have no impact on my conclusion that a 10.0% ROE is reasonable for Kentucky Power.

BAUDINO PROXY GROUP

	Company		(a) **Allowed ROE**	
1	Alliant Energy		10.00%	
2	Ameren Corp.		8.70%	
3	American Elec Pwr		10.10%	
4	Avangrid, Inc.		8.78%	
5	Black Hills Corp.		9.37%	
6	CMS Energy Corp.		10.00%	
7	Consolidated Edison		8.90%	
8	DTE Energy Co.		9.90%	
9	Duke Energy Corp.		10.10%	
10	Entergy Corp.		9.95%	
11	Evergy Inc.		9.30%	
12	Eversource Energy		9.64%	
13	Exelon Corp.		9.58%	
14	Fortis Inc.		9.31%	
15	NextEra Energy, Inc.		10.60%	
16	OGE Energy Corp.		9.50%	
17	Pub Sv Enterprise Grp.		9.60%	
18	Sempra Energy		10.35%	
19	Southern Company		12.50%	
20	WEC Energy Group		9.70%	
21	Xcel Energy Inc.		9.60%	
	Range of Reasonableness	**8.70%**	--	**12.50%**
	Midpoint		**10.60%**	
	Average		**9.79%**	

(a) The Value Line Investment Survey (Jul. 24, Aug. 14 and Sep. 11, 2020).

SUMMARY OF UPDATED RESULTS

Method	Average		Midpoint
DCF			
Value Line	8.9%		10.3%
IBES	9.1%		8.9%
Zacks	9.3%		9.2%
Internal br + sv	8.2%		8.7%
CAPM			
Current Bond Yield	10.6%		10.8%
Projected Bond Yield	10.7%		10.9%
Empirical CAPM			
Current Bond Yield	10.9%		11.1%
Projected Bond Yield	11.0%		11.1%
Utility Risk Premium			
Current Bond Yield		9.3%	
Projected Bond Yield		10.1%	
Expected Earnings	10.6%		10.6%

ROE Recommendation			
Cost of Equity Range	9.3%	--	10.4%
Flotation Cost Adjustment			
Dividend Yield		3.7%	
Flotation Cost Percentage		2.9%	
Adjustment		0.1%	
Recommended ROE Range	**9.4%**	**--**	**10.5%**
Midpoint		**10.0%**	

DIVIDEND YIELD

	Company	(a) Price	(b) Dividends	Yield
1	Alliant Energy	$52.57	$1.52	2.9%
2	Ameren Corp.	$78.32	$2.08	2.7%
3	American Elec Pwr	$79.93	$2.96	3.7%
4	Avangrid, Inc.	$49.14	$1.76	3.6%
5	Black Hills Corp.	$54.70	$2.23	4.1%
6	CMS Energy Corp.	$60.86	$1.71	2.8%
7	Consolidated Edison	$73.86	$3.11	4.2%
8	DTE Energy Co.	$116.40	$4.34	3.7%
9	Duke Energy Corp.	$82.70	$3.88	4.7%
10	Entergy Corp.	$97.57	$3.80	3.9%
11	Evergy Inc.	$51.51	$2.14	4.2%
12	Eversource Energy	$83.51	$2.34	2.8%
13	Exelon Corp.	$36.20	$1.57	4.3%
14	Fortis Inc.	$40.19	$2.02	5.0%
15	NextEra Energy, Inc.	$280.39	$5.88	2.1%
16	OGE Energy Corp.	$30.53	$1.64	5.4%
17	Pub Sv Enterprise Grp.	$52.92	$2.00	3.8%
18	Sempra Energy	$120.32	$4.34	3.6%
19	Southern Company	$52.95	$2.60	4.9%
20	WEC Energy Group	$95.45	$2.66	2.8%
21	Xcel Energy Inc.	$69.04	$1.77	2.6%
	Average			**3.7%**

(a) Average of closing prices for 30 trading days ended Oct. 2, 2020.

(b) The Value Line Investment Survey, Summary & Index (Oct. 2, 2020).

GROWTH RATES

		(a)	(b)	(c)	(d)
		Earnings Growth			**br+sv**
	Company	**Value Line**	**IBES**	**Zacks**	**Growth**
1	Alliant Energy	5.5%	5.3%	5.5%	4.7%
2	Ameren Corp.	6.0%	6.0%	6.9%	6.0%
3	American Elec Pwr	6.0%	5.6%	5.6%	5.7%
4	Avangrid, Inc.	4.0%	4.6%	5.3%	1.4%
5	Black Hills Corp.	3.5%	4.7%	5.8%	3.8%
6	CMS Energy Corp.	7.5%	7.1%	7.0%	7.2%
7	Consolidated Edison	3.0%	2.6%	2.0%	3.3%
8	DTE Energy Co.	6.0%	6.0%	5.7%	5.3%
9	Duke Energy Corp.	5.0%	1.6%	4.3%	3.1%
10	Entergy Corp.	3.0%	5.4%	5.4%	4.9%
11	Evergy Inc.	4.5%	6.8%	6.4%	2.3%
12	Eversource Energy	5.5%	6.4%	6.6%	4.7%
13	Exelon Corp.	5.0%	-3.5%	4.0%	4.1%
14	Fortis Inc.	2.5%	5.4%	6.1%	1.5%
15	NextEra Energy, Inc.	10.0%	8.1%	7.9%	5.5%
16	OGE Energy Corp.	3.0%	2.4%	3.7%	2.7%
17	Pub Sv Enterprise Grp.	5.0%	1.5%	3.5%	5.2%
18	Sempra Energy	10.0%	6.3%	7.4%	7.3%
19	Southern Company	3.0%	4.6%	4.0%	3.6%
20	WEC Energy Group	6.0%	6.0%	5.9%	4.2%
21	Xcel Energy Inc.	6.0%	5.9%	5.8%	5.0%

(a) The Value Line Investment Survey (Jul. 24, Aug. 14 and Sep. 11, 2020).
(b) www.finance.yahoo.com (retreived Oct. 5, 2020).
(c) www.zacks.com (retrieved Oct. 5, 2020).
(d) See Exh. AMM-17.

DCF COST OF EQUITY ESTIMATES

		(a)	(a)	(a)	(a)
		Earnings Growth			br+sv
	Company	**Value Line**	**IBES**	**Zacks**	**Growth**
1	Alliant Energy	8.4%	8.2%	8.4%	7.6%
2	Ameren Corp.	8.7%	8.7%	9.5%	8.6%
3	American Elec Pwr	9.7%	9.3%	9.3%	9.4%
4	Avangrid, Inc.	7.6%	8.2%	8.9%	4.9%
5	Black Hills Corp.	7.6%	8.8%	9.8%	7.9%
6	CMS Energy Corp.	10.3%	9.9%	9.8%	10.1%
7	Consolidated Edison	7.2%	6.8%	6.2%	7.6%
8	DTE Energy Co.	9.7%	9.7%	9.4%	9.0%
9	Duke Energy Corp.	9.7%	6.3%	9.0%	7.8%
10	Entergy Corp.	6.9%	9.3%	9.3%	8.8%
11	Evergy Inc.	8.7%	11.0%	10.6%	6.4%
12	Eversource Energy	8.3%	9.2%	9.4%	7.5%
13	Exelon Corp.	9.3%	0.9%	8.3%	8.5%
14	Fortis Inc.	7.5%	10.4%	11.1%	6.5%
15	NextEra Energy, Inc.	12.1%	10.2%	10.0%	7.6%
16	OGE Energy Corp.	8.4%	7.8%	9.1%	8.0%
17	Pub Sv Enterprise Grp.	8.8%	5.2%	7.2%	9.0%
18	Sempra Energy	13.6%	9.9%	11.0%	10.9%
19	Southern Company	7.9%	9.5%	8.9%	8.5%
20	WEC Energy Group	8.8%	8.7%	8.7%	6.9%
21	Xcel Energy Inc.	8.6%	8.4%	8.4%	7.6%
	Average (b)	**8.9%**	**9.1%**	**9.3%**	**8.2%**
	Midpoint (b,c)	**10.3%**	**8.9%**	**9.2%**	**8.7%**

(a) Sum of dividend yield (Exh. AMM-15, p. 1) and respective growth rate (Exh. AMM-15, p. 2).
(b) Excludes highlighted figures.
(c) Average of low and high values.

LOW-END THRESHOLD ADJUSTMENTS

Atlantic Path 15 / Startrans / So. Cal Edison		*Pioneer Transmission*	
	Baa Yield		**Baa Yield**
Jun-07	6.54%	Apr-08	6.81%
Jul-07	6.49%	May-08	6.79%
Aug-07	6.51%	Jun-08	6.93%
Sep-07	6.45%	Jul-08	6.97%
Oct-07	6.36%	Aug-08	6.98%
Nov-07	6.27%	Sep-08	7.15%

	Current		**Projected**	
Historical Baa Bond Yield	6.69%	(a)	6.69%	(a)
Current Baa Bond Yield	3.37%	(b)	4.79%	(c)
Change in Bond Yield	-3.32%		-1.90%	
Risk Premium/Interest Rate Relationship	-0.42103	(d)	-0.42103	(d)
Adjustment to Low-end Threshold	1.40%		0.80%	
Current Baa Bond Yield	3.37%		4.79%	
Original Threshold	1.00%		1.00%	
Adjustment	1.40%		0.80%	
Adjusted Low-end Threshold	**5.77%**		**6.59%**	

Low-end Test -- FERC Opinion No. 569-A	
Current Baa Bond Yield	3.37%
CAPM Market Risk Premium (e)	10.17%
Risk Premium Factor (f)	20.00%
Adjustment to Low-end Threshold	2.03%
Adjusted Low-end Threshold	**5.40%**

(a) Average Baa utility bond yield for 6-mo. periods ending Nov. 2007 and Sep. 2008.

(b) Average Baa utility bond yield for 6-months ended Sep. 2020.

(c) Average Baa utility bond yield for 2021-25 based on data from IHS Markit, Long-Term Macro Forecast - Baseline (May 28, 2020); Energy Information Administration, Annual Energy Outlook 2020 (Jan. 29, 2020), Moody's Investors Service at www.credittrends.com.

(d) Exh. AMM-19, page 4.

(e) Exh. AMM-17, page 1.

(f) 171 FERC ¶ 61,154, Docket Nos. EL14-12-004 and EL15-45-013, Opinion No. 569-A, Order on Rehearing (issued May 21, 2020).

BR+SV GROWTH RATE

		(a)	(a)	(a)			(b)	(c)		(d)	(e)		
			2024				Adjustment				"sv" Factor		
	Company	**EPS**	**DPS**	**BVPS**	**b**	**r**	**Factor**	**Adjusted r**	**br**	**s**	**v**	**sv**	**br + sv**
1	Alliant Energy	$3.00	$2.00	$28.25	33.3%	10.6%	1.0150	10.8%	3.6%	0.0266	0.4053	1.08%	**4.7%**
2	Ameren Corp.	$4.50	$2.45	$44.50	45.6%	10.1%	1.0398	10.5%	4.8%	0.0303	0.3862	1.17%	**6.0%**
3	American Elec Pwr	$5.50	$3.55	$53.00	35.5%	10.4%	1.0402	10.8%	3.8%	0.0421	0.4421	1.86%	**5.7%**
4	Avangrid, Inc.	$2.50	$1.80	$51.75	28.0%	4.8%	1.0048	4.9%	1.4%	(0.0000)	(0.2176)	0.00%	**1.4%**
5	Black Hills Corp.	$4.25	$2.75	$46.75	35.3%	9.1%	1.0232	9.3%	3.3%	0.0134	0.3968	0.53%	**3.8%**
6	CMS Energy Corp.	$3.50	$2.15	$25.50	38.6%	13.7%	1.0429	14.3%	5.5%	0.0283	0.6077	1.72%	**7.2%**
7	Consolidated Edison	$5.00	$3.50	$62.50	30.0%	8.0%	1.0233	8.2%	2.5%	0.0274	0.3243	0.89%	**3.3%**
8	DTE Energy Co.	$8.50	$5.20	$79.25	38.8%	10.7%	1.0326	11.1%	4.3%	0.0229	0.4339	0.99%	**5.3%**
9	Duke Energy Corp.	$6.00	$4.15	$71.00	30.8%	8.5%	1.0214	8.6%	2.7%	0.0185	0.2526	0.47%	**3.1%**
10	Entergy Corp.	$7.00	$4.55	$64.00	35.0%	10.9%	1.0267	11.2%	3.9%	0.0204	0.4776	0.97%	**4.9%**
11	Evergy Inc.	$3.50	$2.55	$42.25	27.1%	8.3%	1.0107	8.4%	2.3%	0.0005	0.3964	0.02%	**2.3%**
12	Eversource Energy	$4.50	$2.85	$49.00	36.7%	9.2%	1.0341	9.5%	3.5%	0.0306	0.4061	1.24%	**4.7%**
13	Exelon Corp.	$3.50	$1.90	$40.25	45.7%	8.7%	1.0220	8.9%	4.1%	0.0043	0.1950	0.08%	**4.1%**
14	Fortis Inc.	$3.00	$2.50	$43.75	16.7%	6.9%	1.0213	7.0%	1.2%	0.0097	0.3519	0.34%	**1.5%**
15	NextEra Energy, Inc.	$12.25	$8.20	$98.75	33.1%	12.4%	1.0295	12.8%	4.2%	0.0191	0.6624	1.27%	**5.5%**
16	OGE Energy Corp.	$2.50	$1.95	$20.50	22.0%	12.2%	0.9992	12.2%	2.7%	(0.0002)	0.5684	-0.01%	**2.7%**
17	Pub Sv Enterprise Grp.	$4.25	$2.30	$38.50	45.9%	11.0%	1.0249	11.3%	5.2%	0.0006	0.3583	0.02%	**5.2%**
18	Sempra Energy	$9.50	$5.60	$88.75	41.1%	10.7%	1.0533	11.3%	4.6%	0.0578	0.4621	2.67%	**7.3%**
19	Southern Company	$3.75	$2.86	$30.50	23.7%	12.3%	1.0188	12.5%	3.0%	0.0135	0.4917	0.66%	**3.6%**
20	WEC Energy Group	$4.75	$3.20	$38.00	32.6%	12.5%	1.0170	12.7%	4.1%	0.0001	0.6000	0.01%	**4.2%**
21	Xcel Energy Inc.	$3.50	$2.15	$32.35	38.6%	10.8%	1.0292	11.1%	4.3%	0.0163	0.4608	0.75%	**5.0%**

DCF MODEL

BR+SV GROWTH RATE

		(a)	(a)	(f)	(a)	(a)	(f)	(g)	(a)	(a)		(h)	(a)	(a)	(g)
		2019			**2024**			**Chg**	**2024**				**Common Shares**		
	Company	**Eq Ratio**	**Tot Cap**	**Com Eq**	**Eq Ratio**	**Tot Cap**	**Com Eq**	**Equity**	**High**	**Low**	**Avg.**	**M/B**	**2019**	**2024**	**Growth**
1	Alliant Energy	48.5%	$10,226	$4,960	48.0%	$12,000	$5,760	3.0%	$55.00	$40.00	$47.50	1.681	245.02	265.00	1.58%
2	Ameren Corp.	47.1%	$17,116	$8,062	49.0%	$24,500	$12,005	8.3%	$85.00	$60.00	$72.50	1.629	246.20	270.00	1.86%
3	American Elec Pwr	43.9%	$44,759	$19,649	48.0%	$61,200	$29,376	8.4%	$105.00	$85.00	$95.00	1.792	494.17	555.00	2.35%
4	Avangrid, Inc.	69.4%	$21,953	$15,235	57.5%	$27,800	$15,985	1.0%	$50.00	$35.00	$42.50	0.821	309.01	309.00	0.00%
5	Black Hills Corp.	42.9%	$5,502	$2,360	48.0%	$6,200	$2,976	4.7%	$90.00	$65.00	$77.50	1.658	61.48	64.00	0.81%
6	CMS Energy Corp.	29.4%	$17,082	$5,022	32.0%	$24,100	$7,712	9.0%	$75.00	$55.00	$65.00	2.549	283.86	300.00	1.11%
7	Consolidated Edison	49.3%	$36,549	$18,019	50.0%	$45,500	$22,750	4.8%	$100.00	$85.00	$92.50	1.480	333.00	365.00	1.85%
8	DTE Energy Co.	42.3%	$27,607	$11,678	41.5%	$39,000	$16,185	6.7%	$160.00	$120.00	$140.00	1.767	192.21	205.00	1.30%
9	Duke Energy Corp.	44.1%	########	$44,897	45.0%	########	$55,620	4.4%	$110.00	$80.00	$95.00	1.338	733.00	785.00	1.38%
10	Entergy Corp.	37.1%	$27,557	$10,224	39.5%	$33,800	$13,351	5.5%	$140.00	$105.00	$122.50	1.914	199.15	210.00	1.07%
11	Evergy Inc.	49.4%	$17,337	$8,564	46.5%	$20,500	$9,533	2.2%	$80.00	$60.00	$70.00	1.657	226.64	227.00	0.03%
12	Eversource Energy	46.6%	$27,097	$12,627	46.5%	$38,200	$17,763	7.1%	$90.00	$75.00	$82.50	1.684	329.88	361.00	1.82%
13	Exelon Corp.	50.4%	$63,943	$32,227	50.0%	$80,300	$40,150	4.5%	$60.00	$40.00	$50.00	1.242	973.00	990.00	0.35%
14	Fortis Inc.	41.8%	$40,445	$16,906	43.5%	$48,100	$20,924	4.4%	$80.00	$55.00	$67.50	1.543	463.30	478.00	0.63%
15	NextEra Energy, Inc.	49.6%	$74,548	$36,976	50.5%	$98,400	$49,692	6.1%	$320.00	$265.00	$292.50	2.962	489.00	505.00	0.65%
16	OGE Energy Corp.	56.4%	$7,335	$4,137	51.0%	$8,050	$4,106	-0.2%	$55.00	$40.00	$47.50	2.317	200.10	200.00	-0.01%
17	Pub Sv Enterprise Grp.	52.3%	$28,832	$15,079	50.0%	$38,700	$19,350	5.1%	$65.00	$55.00	$60.00	1.558	504.00	505.00	0.04%
18	Sempra Energy	43.4%	$40,734	$17,679	51.5%	$58,500	$30,128	11.3%	$190.00	$140.00	$165.00	1.859	291.71	340.00	3.11%
19	Southern Company	39.5%	$69,594	$27,490	39.5%	$84,000	$33,180	3.8%	$70.00	$50.00	$60.00	1.967	#######	#######	0.69%
20	WEC Energy Group	47.4%	$21,355	$10,122	48.0%	$25,000	$12,000	3.5%	$105.00	$85.00	$95.00	2.500	315.43	315.50	0.00%
21	Xcel Energy Inc.	43.2%	$30,646	$13,239	42.5%	$41,700	$17,723	6.0%	$65.00	$55.00	$60.00	1.855	524.54	548.00	0.88%

(a) The Value Line Investment Survey (Jul. 24, Aug. 14 and Sep. 11, 2020).
(h) Average of High and Low expected market prices divided by 2024 BVPS.
(e) Computed as 1 - B/M Ratio.
(b) Computed using the formula 2*(1+5-Yr. Change in Equity)/(2+5 Yr. Change in Equity).
(g) Five-year compound rate of change.
(c) Product of average year-end "r" for 2024 and Adjustment Factor.
(d) Product of change in common shares outstanding and M/B Ratio.
(f) Product of total capital and equity ratio.

CURRENT BOND YIELD

		(a)	(b)		(c)		(d)		(d)	(e)	
		Market Return (R_m)									Size
		Div	Proj.	Cost of	Risk-Free	Risk		Unadjusted	Market	Size	Adjusted
	Company	Yield	Growth	Equity	Rate	Premium	Beta	CAPM	Cap	Adjustment	CAPM
1	Alliant Energy	2.3%	9.2%	11.6%	1.4%	10.2%	0.85	10.0%	$13,500.0	0.50%	10.5%
2	Ameren Corp.	2.3%	9.2%	11.6%	1.4%	10.2%	0.80	9.5%	$20,000.0	0.50%	10.0%
3	American Elec Pwr	2.3%	9.2%	11.6%	1.4%	10.2%	0.75	9.0%	$39,000.0	-0.28%	8.7%
4	Avangrid, Inc.	2.3%	9.2%	11.6%	1.4%	10.2%	0.80	9.5%	$15,000.0	0.50%	10.0%
5	Black Hills Corp.	2.3%	9.2%	11.6%	1.4%	10.2%	0.95	11.1%	$3,800.0	1.10%	12.2%
6	CMS Energy Corp.	2.3%	9.2%	11.6%	1.4%	10.2%	0.80	9.5%	$17,000.0	0.50%	10.0%
7	Consolidated Edison	2.3%	9.2%	11.6%	1.4%	10.2%	0.75	9.0%	$25,000.0	0.50%	9.5%
8	DTE Energy Co.	2.3%	9.2%	11.6%	1.4%	10.2%	0.90	10.6%	$23,000.0	0.50%	11.1%
9	Duke Energy Corp.	2.3%	9.2%	11.6%	1.4%	10.2%	0.85	10.0%	$62,000.0	-0.28%	9.8%
10	Entergy Corp.	2.3%	9.2%	11.6%	1.4%	10.2%	0.95	11.1%	$20,000.0	0.50%	11.6%
11	Evergy Inc.	2.3%	9.2%	11.6%	1.4%	10.2%	1.00	11.6%	$12,000.0	0.73%	12.3%
12	Eversource Energy	2.3%	9.2%	11.6%	1.4%	10.2%	0.90	10.6%	$30,000.0	0.50%	11.1%
13	Exelon Corp.	2.3%	9.2%	11.6%	1.4%	10.2%	0.95	11.1%	$37,000.0	-0.28%	10.8%
14	Fortis Inc.	2.3%	9.2%	11.6%	1.4%	10.2%	0.80	9.5%	$24,000.0	0.50%	10.0%
15	NextEra Energy, Inc.	2.3%	9.2%	11.6%	1.4%	10.2%	0.85	10.0%	$136,000.0	-0.28%	9.8%
16	OGE Energy Corp.	2.3%	9.2%	11.6%	1.4%	10.2%	1.05	12.1%	$6,400.0	0.79%	12.9%
17	Pub Sv Enterprise Grp.	2.3%	9.2%	11.6%	1.4%	10.2%	0.90	10.6%	$28,000.0	0.50%	11.1%
18	Sempra Energy	2.3%	9.2%	11.6%	1.4%	10.2%	0.95	11.1%	$35,000.0	-0.28%	10.8%
19	Southern Company	2.3%	9.2%	11.6%	1.4%	10.2%	0.90	10.6%	$57,000.0	-0.28%	10.3%
20	WEC Energy Group	2.3%	9.2%	11.6%	1.4%	10.2%	0.80	9.5%	$30,000.0	0.50%	10.0%
21	Xcel Energy Inc.	2.3%	9.2%	11.6%	1.4%	10.2%	0.80	9.5%	$34,000.0	-0.28%	9.3%
	Average							**10.3%**			**10.6%**
	Midpoint (f)							**10.6%**			**10.8%**

(a) Weighted average for www.valueline.com (retrieved Oct. 1, 2020).

(b) Average of weighted average earnings growth rates from IBES, Value Line Investment Survey, and Zacks for dividend-paying stocks in the S&P 500 based on data from http://finance.yahoo.com (retrieved Oct. 2, 2020), www.valueline.com (retrieved Oct. 1, 2020), and www.zacks.com (retrieved Oct. 6, 2020).

(c) Average yield on 30-year Treasury bonds for the six-months ending Sep. 2020 based on data from the Federal Reserve at https://fred.stlouisfed.org/.

(d) The Value Line Investment Survey (Jul. 24, Aug. 14 and Sep. 11, 2020).

(e) Duff & Phelps, 2020 CRSP Deciles Size Study -- Supplementary Data Exhibits, Cost of Capital Navigator.

(f) Average of low and high values.

PROJECTED BOND YIELD

		(a)	(b)		(c)		(d)		(d)	(e)	
		Market Return (R_m)									Size
	Company	Div Yield	Proj. Growth	Cost of Equity	Risk-Free Rate	Risk Premium	Beta	Unadjusted CAPM	Market Cap	Size Adjustment	Adjusted CAPM
1	Alliant Energy	2.3%	9.2%	11.6%	2.2%	9.4%	0.85	10.2%	$13,500.0	0.50%	10.7%
2	Ameren Corp.	2.3%	9.2%	11.6%	2.2%	9.4%	0.80	9.7%	$20,000.0	0.50%	10.2%
3	American Elec Pwr	2.3%	9.2%	11.6%	2.2%	9.4%	0.75	9.2%	$39,000.0	-0.28%	8.9%
4	Avangrid, Inc.	2.3%	9.2%	11.6%	2.2%	9.4%	0.80	9.7%	$15,000.0	0.50%	10.2%
5	Black Hills Corp.	2.3%	9.2%	11.6%	2.2%	9.4%	0.95	11.1%	$3,800.0	1.10%	12.2%
6	CMS Energy Corp.	2.3%	9.2%	11.6%	2.2%	9.4%	0.80	9.7%	$17,000.0	0.50%	10.2%
7	Consolidated Edison	2.3%	9.2%	11.6%	2.2%	9.4%	0.75	9.2%	$25,000.0	0.50%	9.7%
8	DTE Energy Co.	2.3%	9.2%	11.6%	2.2%	9.4%	0.90	10.6%	$23,000.0	0.50%	11.1%
9	Duke Energy Corp.	2.3%	9.2%	11.6%	2.2%	9.4%	0.85	10.2%	$62,000.0	-0.28%	9.9%
10	Entergy Corp.	2.3%	9.2%	11.6%	2.2%	9.4%	0.95	11.1%	$20,000.0	0.50%	11.6%
11	Evergy Inc.	2.3%	9.2%	11.6%	2.2%	9.4%	1.00	11.6%	$12,000.0	0.73%	12.3%
12	Eversource Energy	2.3%	9.2%	11.6%	2.2%	9.4%	0.90	10.6%	$30,000.0	0.50%	11.1%
13	Exelon Corp.	2.3%	9.2%	11.6%	2.2%	9.4%	0.95	11.1%	$37,000.0	-0.28%	10.8%
14	Fortis Inc.	2.3%	9.2%	11.6%	2.2%	9.4%	0.80	9.7%	$24,000.0	0.50%	10.2%
15	NextEra Energy, Inc.	2.3%	9.2%	11.6%	2.2%	9.4%	0.85	10.2%	$136,000.0	-0.28%	9.9%
16	OGE Energy Corp.	2.3%	9.2%	11.6%	2.2%	9.4%	1.05	12.0%	$6,400.0	0.79%	12.8%
17	Pub Sv Enterprise Grp.	2.3%	9.2%	11.6%	2.2%	9.4%	0.90	10.6%	$28,000.0	0.50%	11.1%
18	Sempra Energy	2.3%	9.2%	11.6%	2.2%	9.4%	0.95	11.1%	$35,000.0	-0.28%	10.8%
19	Southern Company	2.3%	9.2%	11.6%	2.2%	9.4%	0.90	10.6%	$57,000.0	-0.28%	10.4%
20	WEC Energy Group	2.3%	9.2%	11.6%	2.2%	9.4%	0.80	9.7%	$30,000.0	0.50%	10.2%
21	Xcel Energy Inc.	2.3%	9.2%	11.6%	2.2%	9.4%	0.80	9.7%	$34,000.0	-0.28%	9.4%
	Average							**10.4%**			**10.7%**
	Midpoint (f)							**10.6%**			**10.9%**

(a) Weighted average for www.valueline.com (retrieved Oct. 1, 2020).

(b) Average of weighted average earnings growth rates from IBES, Value Line Investment Survey, and Zacks for dividend-paying stocks in the S&P 500 based on data from http://finance.yahoo.com (retrieved Oct. 2, 2020), www.valueline.com (retrieved Oct. 1, 2020), and www.zacks.com (retrieved Oct. 6, 2020).

(c) Average yield on 30-year Treasury bonds for 2021-25 based on data from the Value Line Investment Survey, Forecast for the U.S. Economy (Aug. 28, 2020); IHS Markit, Long-Term Macro Forecast - Baseline (May 28, 2020); & Wolters Kluwer, Blue Chip Financial Forecasts (Jun. 1, 2020).

(d) The Value Line Investment Survey (Jul. 24, Aug. 14 and Sep. 11, 2020).

(e) Duff & Phelps, 2020 CRSP Deciles Size Study -- Supplementary Data Exhibits, Cost of Capital Navigator.

(f) Average of low and high values.

EMPIRICAL CAPM

CURRENT BOND YIELD

		(a)	(b)		(c)		(d)		(e)	(d)				(e)	(f)	
		Market Return (R_m)														Size
		Div	Proj.	Cost of	Risk-Free	Risk	Unadjusted RP		Beta Adjusted RP			Total	Unadjusted	Market	Size	Adjusted
	Company	Yield	Growth	Equity	Rate	Premium	Weight	RP^1	Beta	Weight	RP^2	RP	K_e	Cap	Adjustment	K_e
1	Alliant Energy	2.3%	9.2%	11.6%	1.4%	10.2%	25%	2.5%	0.85	75%	6.5%	9.0%	10.4%	$13,500.0	0.50%	10.9%
2	Ameren Corp.	2.3%	9.2%	11.6%	1.4%	10.2%	25%	2.5%	0.80	75%	6.1%	8.6%	10.0%	$20,000.0	0.50%	10.5%
3	American Elec Pwr	2.3%	9.2%	11.6%	1.4%	10.2%	25%	2.5%	0.75	75%	5.7%	8.3%	9.7%	$39,000.0	-0.28%	9.4%
4	Avangrid, Inc.	2.3%	9.2%	11.6%	1.4%	10.2%	25%	2.5%	0.80	75%	6.1%	8.6%	10.0%	$15,000.0	0.50%	10.5%
5	Black Hills Corp.	2.3%	9.2%	11.6%	1.4%	10.2%	25%	2.5%	0.95	75%	7.2%	9.8%	11.2%	$3,800.0	1.10%	12.3%
6	CMS Energy Corp.	2.3%	9.2%	11.6%	1.4%	10.2%	25%	2.5%	0.80	75%	6.1%	8.6%	10.0%	$17,000.0	0.50%	10.5%
7	Consolidated Edison	2.3%	9.2%	11.6%	1.4%	10.2%	25%	2.5%	0.75	75%	5.7%	8.3%	9.7%	$25,000.0	0.50%	10.2%
8	DTE Energy Co.	2.3%	9.2%	11.6%	1.4%	10.2%	25%	2.5%	0.90	75%	6.9%	9.4%	10.8%	$23,000.0	0.50%	11.3%
9	Duke Energy Corp.	2.3%	9.2%	11.6%	1.4%	10.2%	25%	2.5%	0.85	75%	6.5%	9.0%	10.4%	$62,000.0	-0.28%	10.1%
10	Entergy Corp.	2.3%	9.2%	11.6%	1.4%	10.2%	25%	2.5%	0.95	75%	7.2%	9.8%	11.2%	$20,000.0	0.50%	11.7%
11	Evergy Inc.	2.3%	9.2%	11.6%	1.4%	10.2%	25%	2.5%	1.00	75%	7.6%	10.2%	11.6%	$12,000.0	0.73%	12.3%
12	Eversource Energy	2.3%	9.2%	11.6%	1.4%	10.2%	25%	2.5%	0.90	75%	6.9%	9.4%	10.8%	$30,000.0	0.50%	11.3%
13	Exelon Corp.	2.3%	9.2%	11.6%	1.4%	10.2%	25%	2.5%	0.95	75%	7.2%	9.8%	11.2%	$37,000.0	-0.28%	10.9%
14	Fortis Inc.	2.3%	9.2%	11.6%	1.4%	10.2%	25%	2.5%	0.80	75%	6.1%	8.6%	10.0%	$24,000.0	0.50%	10.5%
15	NextEra Energy, Inc.	2.3%	9.2%	11.6%	1.4%	10.2%	25%	2.5%	0.85	75%	6.5%	9.0%	10.4%	$136,000.0	-0.28%	10.1%
16	OGE Energy Corp.	2.3%	9.2%	11.6%	1.4%	10.2%	25%	2.5%	1.05	75%	8.0%	10.6%	12.0%	$6,400.0	0.79%	12.7%
17	Pub Sv Enterprise Grp.	2.3%	9.2%	11.6%	1.4%	10.2%	25%	2.5%	0.90	75%	6.9%	9.4%	10.8%	$28,000.0	0.50%	11.3%
18	Sempra Energy	2.3%	9.2%	11.6%	1.4%	10.2%	25%	2.5%	0.95	75%	7.2%	9.8%	11.2%	$35,000.0	-0.28%	10.9%
19	Southern Company	2.3%	9.2%	11.6%	1.4%	10.2%	25%	2.5%	0.90	75%	6.9%	9.4%	10.8%	$57,000.0	-0.28%	10.5%
20	WEC Energy Group	2.3%	9.2%	11.6%	1.4%	10.2%	25%	2.5%	0.80	75%	6.1%	8.6%	10.0%	$30,000.0	0.50%	10.5%
21	Xcel Energy Inc.	2.3%	9.2%	11.6%	1.4%	10.2%	25%	2.5%	0.80	75%	6.1%	8.6%	10.0%	$34,000.0	-0.28%	9.8%
	Average												**10.6%**			**10.9%**
	Midpoint (g)												**10.8%**			**11.1%**

(a) Weighted average for www.valueline.com (retrieved Oct. 1, 2020).

(b) Average of weighted average earnings growth rates from IBES, Value Line Investment Survey, and Zacks for dividend-paying stocks in the S&P 500 based on data from http://finance.yahoo.com (retrieved Oct. 2, 2020), www.valueline.com (retrieved Oct. 1, 2020), and www.zacks.com (retrieved Oct. 6, 2020).

(c) Average yield on 30-year Treasury bonds for the six-months ending Sep. 2020 based on data from the Federal Reserve at https://fred.stlouisfed.org/.

(d) Roger A. Morin, *New Regulatory Finance* , Pub. Util. Reports, Inc. (2006) at 190.

(e) The Value Line Investment Survey (Jul. 24, Aug. 14 and Sep. 11, 2020).

(f) Duff & Phelps, 2020 CRSP Deciles Size Study -- Supplementary Data Exhibits, Cost of Capital Navigator.

(g) Average of low and high values.

PROJECTED BOND YIELD

		(a)	(b)		(c)		(d)		(e)	(d)				(e)	(f)	
		Market Return (R_m)														Size
		Div	Proj.	Cost of	Risk-Free	Risk	Unadjusted RP		Beta Adjusted RP			Total	Unadjusted	Market	Size	Adjusted
	Company	Yield	Growth	Equity	Rate	Premium	Weight	*RP*[1]	Beta	Weight	*RP*[2]	RP	K_e	Cap	Adjustment	K_e
1	Alliant Energy	2.3%	9.2%	11.6%	2.2%	9.4%	25%	2.3%	0.85	75%	6.0%	8.3%	10.5%	$13,500.0	0.50%	11.0%
2	Ameren Corp.	2.3%	9.2%	11.6%	2.2%	9.4%	25%	2.3%	0.80	75%	5.6%	8.0%	10.2%	$20,000.0	0.50%	10.7%
3	American Elec Pwr	2.3%	9.2%	11.6%	2.2%	9.4%	25%	2.3%	0.75	75%	5.3%	7.6%	9.8%	$39,000.0	-0.28%	9.5%
4	Avangrid, Inc.	2.3%	9.2%	11.6%	2.2%	9.4%	25%	2.3%	0.80	75%	5.6%	8.0%	10.2%	$15,000.0	0.50%	10.7%
5	Black Hills Corp.	2.3%	9.2%	11.6%	2.2%	9.4%	25%	2.3%	0.95	75%	6.7%	9.0%	11.2%	$3,800.0	1.10%	12.3%
6	CMS Energy Corp.	2.3%	9.2%	11.6%	2.2%	9.4%	25%	2.3%	0.80	75%	5.6%	8.0%	10.2%	$17,000.0	0.50%	10.7%
7	Consolidated Edison	2.3%	9.2%	11.6%	2.2%	9.4%	25%	2.3%	0.75	75%	5.3%	7.6%	9.8%	$25,000.0	0.50%	10.3%
8	DTE Energy Co.	2.3%	9.2%	11.6%	2.2%	9.4%	25%	2.3%	0.90	75%	6.3%	8.7%	10.9%	$23,000.0	0.50%	11.4%
9	Duke Energy Corp.	2.3%	9.2%	11.6%	2.2%	9.4%	25%	2.3%	0.85	75%	6.0%	8.3%	10.5%	$62,000.0	-0.28%	10.2%
10	Entergy Corp.	2.3%	9.2%	11.6%	2.2%	9.4%	25%	2.3%	0.95	75%	6.7%	9.0%	11.2%	$20,000.0	0.50%	11.7%
11	Evergy Inc.	2.3%	9.2%	11.6%	2.2%	9.4%	25%	2.3%	1.00	75%	7.0%	9.4%	11.6%	$12,000.0	0.73%	12.3%
12	Eversource Energy	2.3%	9.2%	11.6%	2.2%	9.4%	25%	2.3%	0.90	75%	6.3%	8.7%	10.9%	$30,000.0	0.50%	11.4%
13	Exelon Corp.	2.3%	9.2%	11.6%	2.2%	9.4%	25%	2.3%	0.95	75%	6.7%	9.0%	11.2%	$37,000.0	-0.28%	10.9%
14	Fortis Inc.	2.3%	9.2%	11.6%	2.2%	9.4%	25%	2.3%	0.80	75%	5.6%	8.0%	10.2%	$24,000.0	0.50%	10.7%
15	NextEra Energy, Inc.	2.3%	9.2%	11.6%	2.2%	9.4%	25%	2.3%	0.85	75%	6.0%	8.3%	10.5%	$136,000.0	-0.28%	10.2%
16	OGE Energy Corp.	2.3%	9.2%	11.6%	2.2%	9.4%	25%	2.3%	1.05	75%	7.4%	9.7%	11.9%	$6,400.0	0.79%	12.7%
17	Pub Sv Enterprise Grp.	2.3%	9.2%	11.6%	2.2%	9.4%	25%	2.3%	0.90	75%	6.3%	8.7%	10.9%	$28,000.0	0.50%	11.4%
18	Sempra Energy	2.3%	9.2%	11.6%	2.2%	9.4%	25%	2.3%	0.95	75%	6.7%	9.0%	11.2%	$35,000.0	-0.28%	10.9%
19	Southern Company	2.3%	9.2%	11.6%	2.2%	9.4%	25%	2.3%	0.90	75%	6.3%	8.7%	10.9%	$57,000.0	-0.28%	10.6%
20	WEC Energy Group	2.3%	9.2%	11.6%	2.2%	9.4%	25%	2.3%	0.80	75%	5.6%	8.0%	10.2%	$30,000.0	0.50%	10.7%
21	Xcel Energy Inc.	2.3%	9.2%	11.6%	2.2%	9.4%	25%	2.3%	0.80	75%	5.6%	8.0%	10.2%	$34,000.0	-0.28%	9.9%
	Average												**10.7%**			**11.0%**
	Midpoint (g)												**10.9%**			**11.1%**

(a) Weighted average for www.valueline.com (retrieved Oct. 1, 2020).

(b) Average of weighted average earnings growth rates from IBES, Value Line Investment Survey, and Zacks for dividend-paying stocks in the S&P 500 based on data from http://finance.yahoo.com (retrieved Oct. 2, 2020), www.valueline.com (retrieved Oct. 1, 2020), and www.zacks.com (retrieved Oct. 6, 2020).

(c) Average yield on 30-year Treasury bonds for 2021-25 based on data from the Value Line Investment Survey, Forecast for the U.S. Economy (Aug. 28, 2020); IHS Markit, Long-Term Macro Forecast - Baseline (May 28, 2020); & Wolters Kluwer, Blue Chip Financial Forecasts (Jun. 1, 2020).

(d) Roger A. Morin, *New Regulatory Finance* , Pub. Util. Reports, Inc. (2006) at 190.

(e) The Value Line Investment Survey (Jul. 24, Aug. 14 and Sep. 11, 2020).

(f) Duff & Phelps, 2020 CRSP Deciles Size Study -- Supplementary Data Exhibits, Cost of Capital Navigator.

(g) Average of low and high values.

ELECTRIC UTILITY RISK PREMIUM

CURRENT BOND YIELD

Current Equity Risk Premium		
(a)	Avg. Yield over Study Period	8.10%
(b)	Average Utility Bond Yield	3.01%
	Change in Bond Yield	-5.09%
(c)	Risk Premium/Interest Rate Relationship	-0.4210
	Adjustment to Average Risk Premium	2.14%
(a)	Average Risk Premium over Study Period	3.76%
	Adjusted Risk Premium	**5.90%**

Implied Cost of Equity		
(b)	Baa Utility Bond Yield	3.37%
	Adjusted Equity Risk Premium	5.90%
	Risk Premium Cost of Equity	**9.27%**

(a) Exh. AMM-19, page 3.

(b) Average bond yield on all utility bonds and Baa subset for the six-months ending Sep. 2020 based on data from Moody's Investors Service at www.credittrends.com.

(c) Exh. AMM-19, page 4.

ELECTRIC UTILITY RISK PREMIUM

PROJECTED BOND YIELD

Current Equity Risk Premium		
(a)	Avg. Yield over Study Period	8.10%
(b)	Average Utility Bond Yield 2021-2025	4.43%
	Change in Bond Yield	-3.67%
(c)	Risk Premium/Interest Rate Relationship	-0.4210
	Adjustment to Average Risk Premium	1.55%
(a)	Average Risk Premium over Study Period	3.76%
	Adjusted Risk Premium	**5.31%**

Implied Cost of Equity		
(b)	Baa Utility Bond Yield 2021-2025	4.79%
	Adjusted Equity Risk Premium	5.31%
	Risk Premium Cost of Equity	**10.10%**

(a) Exh. AMM-19, page 3.

(b) Yields on all utility bonds and Baa subset based on data from IHS Markit, Long-Term Macro Forecast - Baseline (May 28, 2020); Energy Information Administration, Annual Energy Outlook 2020 (Jan. 29, 2020); & Moody's Investors Service at www.credittrends.com.

(c) Exh. AMM-19, page 4.

AUTHORIZED RETURNS

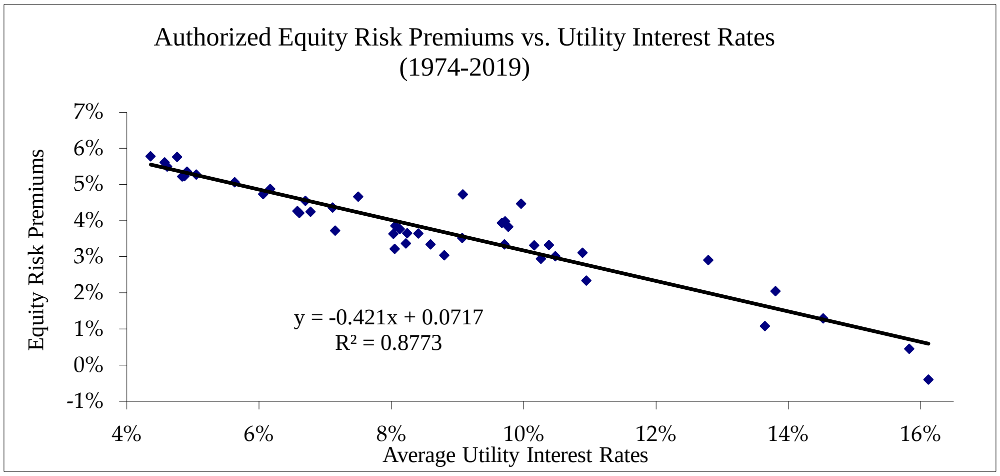
Year	(a) Allowed ROE	(b) Average Utility Bond Yield	Risk Premium
1974	13.10%	9.27%	3.83%
1975	13.20%	9.88%	3.32%
1976	13.10%	9.17%	3.93%
1977	13.30%	8.58%	4.72%
1978	13.20%	9.22%	3.98%
1979	13.50%	10.39%	3.11%
1980	14.23%	13.15%	1.08%
1981	15.22%	15.62%	-0.40%
1982	15.78%	15.33%	0.45%
1983	15.36%	13.31%	2.05%
1984	15.32%	14.03%	1.29%
1985	15.20%	12.29%	2.91%
1986	13.93%	9.46%	4.47%
1987	12.99%	9.98%	3.01%
1988	12.79%	10.45%	2.34%
1989	12.97%	9.66%	3.31%
1990	12.70%	9.76%	2.94%
1991	12.55%	9.21%	3.34%
1992	12.09%	8.57%	3.52%
1993	11.41%	7.56%	3.85%
1994	11.34%	8.30%	3.04%
1995	11.55%	7.91%	3.64%
1996	11.39%	7.74%	3.65%
1997	11.40%	7.63%	3.77%
1998	11.66%	7.00%	4.66%
1999	10.77%	7.55%	3.22%
2000	11.43%	8.09%	3.34%
2001	11.09%	7.72%	3.37%
2002	11.16%	7.53%	3.63%
2003	10.97%	6.61%	4.36%
2004	10.75%	6.20%	4.55%
2005	10.54%	5.67%	4.87%
2006	10.34%	6.08%	4.26%
2007	10.32%	6.11%	4.21%
2008	10.37%	6.65%	3.72%
2009	10.52%	6.28%	4.24%
2010	10.29%	5.56%	4.73%
2011	10.19%	5.13%	5.06%
2012	10.02%	4.26%	5.76%
2013	9.82%	4.55%	5.27%
2014	9.76%	4.41%	5.35%
2015	9.60%	4.37%	5.23%
2016	9.60%	4.11%	5.49%
2017	9.68%	4.07%	5.61%
2018	9.56%	4.34%	5.22%
2019	9.64%	3.86%	5.78%
Average	**11.86%**	**8.10%**	**3.76%**

(a) Major Rate Case Decisions, *Regulatory Focus* , Regulatory Research Associates ("RRA"); *UtilityScope Regulatory Service* , Argus. Data for "general" rate cases (excluding limited-issue rider cases) beginning in 2006 (the first year such data presented by RRA).

(b) Moody's Investors Service.

ELECTRIC UTILITY RISK PREMIUM

REGRESSION RESULTS



SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.936629767
R Square	0.87727532
Adjusted R Square	0.874486122
Standard Error	0.004786234
Observations	46

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	0.007205175	0.007205175	314.5260916	1.15178E-21
Residual	44	0.001007954	2.2908E-05		
Total	45	0.008213129			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	0.071731079	0.00204844	35.01742055	9.02999E-34	0.06760272	0.075859439	0.06760272	0.075859439
X Variable 1	-0.421026691	0.023740031	-17.73488347	1.15178E-21	-0.46887158	-0.373181801	-0.46887158	-0.373181801

EXPECTED EARNINGS APPROACH

UPDATED UTILITY GROUP

		(a)	(b)	(c)
	Company	**Expected Return on Common Equity**	**Adjustment Factor**	**Adjusted Return on Common Equity**
1	Alliant Energy	10.5%	1.0150	10.7%
2	Ameren Corp.	10.0%	1.0398	10.4%
3	American Elec Pwr	10.5%	1.0402	10.9%
4	Avangrid, Inc.	5.0%	1.0048	5.0%
5	Black Hills Corp.	9.0%	1.0232	9.2%
6	CMS Energy Corp.	13.5%	1.0429	14.1%
7	Consolidated Edison	8.0%	1.0233	8.2%
8	DTE Energy Co.	11.0%	1.0326	11.4%
9	Duke Energy Corp.	8.5%	1.0214	8.7%
10	Entergy Corp.	11.0%	1.0267	11.3%
11	Evergy Inc.	8.5%	1.0107	8.6%
12	Eversource Energy	9.0%	1.0341	9.3%
13	Exelon Corp.	9.0%	1.0220	9.2%
14	Fortis Inc.	7.0%	1.0213	7.1%
15	NextEra Energy, Inc.	12.5%	1.0295	12.9%
16	OGE Energy Corp.	12.0%	0.9992	12.0%
17	Pub Sv Enterprise Grp.	11.0%	1.0249	11.3%
18	Sempra Energy	10.5%	1.0533	11.1%
19	Southern Company	12.5%	1.0188	12.7%
20	WEC Energy Group	12.5%	1.0170	12.7%
21	Xcel Energy Inc.	10.5%	1.0292	10.8%
	Average (d)			**10.6%**
	Midpoint (d,e)			**10.6%**

(a) The Value Line Investment Survey (Jul. 24, Aug. 14 and Sep. 11, 2020).
(b) Adjustment to convert year-end return to an average rate of return from Exh. AMM-17.
(c) (a) x (b).
(d) Excludes highlighted values.
(e) Average of low and high values.

DIVIDEND YIELD

	Company	Industry Group	(a) Price	(b) Dividends	Yield
1	Air Products & Chem.	Chemical (Diversified)	$ 286.44	$ 5.36	1.9%
2	Amdocs Ltd.	IT Services	$ 60.73	$ 1.31	2.2%
3	Amgen	Biotechnology	$ 246.85	$ 6.70	2.7%
4	Amphenol Corp.	Electronics	$ 105.69	$ 1.00	0.9%
5	Apple Inc.	Computers/Peripherals	$ 420.53	$ 3.33	0.8%
6	AT&T Inc.	Telecom. Services	$ 29.88	$ 2.10	7.0%
7	Baxter Int'l Inc.	Med Supp Invasive	$ 85.17	$ 0.98	1.2%
8	Bristol-Myers Squibb	Drug	$ 60.51	$ 1.80	3.0%
9	Brown & Brown	Financial Svcs. (Div.)	$ 44.92	$ 0.34	0.8%
10	Brown-Forman 'B'	Beverage	$ 68.98	$ 0.72	1.0%
11	Church & Dwight	Household Products	$ 90.86	$ 0.96	1.1%
12	Cisco Systems	Telecom. Equipment	$ 45.85	$ 1.44	3.1%
13	Coca-Cola	Beverage	$ 47.46	$ 1.68	3.5%
14	Colgate-Palmolive	Household Products	$ 76.00	$ 1.76	2.3%
15	Comcast Corp.	Cable TV	$ 42.85	$ 0.92	2.1%
16	Commerce Bancshs.	Bank (Midwest)	$ 58.38	$ 1.08	1.9%
17	Costco Wholesale	Retail Store	$ 332.54	$ 2.80	0.8%
18	CVS Health	Pharmacy Services	$ 64.31	$ 2.00	3.1%
19	Danaher Corp.	Diversified Co.	$ 200.09	$ 0.72	0.4%
20	Gen'l Mills	Automotive	$ 64.15	$ 1.96	3.1%
21	Hormel Foods	Food Processing	$ 50.91	$ 1.00	2.0%
22	Intel Corp.	Hotel/Gaming	$ 52.12	$ 1.32	2.5%
23	Int'l Flavors & Frag.	Wireless Networking	$ 126.21	$ 3.12	2.5%
24	Johnson & Johnson	Med Supp Non-Invasive	$ 148.46	$ 4.04	2.7%
25	Kellogg	Food Processing	$ 68.97	$ 2.30	3.3%
26	Kimberly-Clark	Household Products	$ 151.72	$ 4.28	2.8%
27	Lilly (Eli)	Drug	$ 157.03	$ 2.96	1.9%
28	Lockheed Martin	Aerospace/Defense	$ 381.27	$ 10.00	2.6%
29	Marsh & McLennan	Financial Svcs. (Div.)	$ 115.27	$ 1.86	1.6%
30	McCormick & Co.	Food Processing	$ 196.44	$ 2.50	1.3%
31	McDonald's Corp.	Restaurant	$ 199.74	$ 5.00	2.5%
32	Merck & Co.	Drug	$ 80.92	$ 2.44	3.0%
33	Microsoft Corp.	Computer Software	$ 208.47	$ 2.04	1.0%
34	Northrop Grumman	Aerospace/Defense	$ 321.97	$ 5.80	1.8%
35	Oracle Corp.	Drug	$ 55.43	$ 0.96	1.7%
36	PepsiCo, Inc.	Beverage	$ 136.36	$ 4.09	3.0%
37	Pfizer, Inc.	Drug	$ 37.80	$ 1.52	4.0%
38	Procter & Gamble	Household Products	$ 130.61	$ 3.16	2.4%
39	Public Storage	R.E.I.T.	$ 195.48	$ 8.00	4.1%
40	Texas Instruments	Environmental	$ 133.79	$ 3.60	2.7%
41	Travelers Cos.	Insurance (Prop/Cas.)	$ 116.89	$ 3.40	2.9%
42	United Parcel Serv.	Air Transport	$ 138.48	$ 4.04	2.9%
43	Verizon Communic.	Telecom. Services	$ 57.37	$ 2.49	4.3%
44	Walmart Inc.	Retail Store	$ 131.45	$ 2.18	1.7%
45	Waste Management	Environmental	$ 109.21	$ 2.18	2.0%
	Average				**2.4%**

(a) Average of closing prices for 30 trading days ended Aug. 21, 2020.
(b) The Value Line Investment Survey, *Summary & Index* (Aug. 21, 2020).

GROWTH RATES

		(a)	(b)	(c)
		Earnings Growth		
	Company	**Value Line**	**IBES**	**Zacks**
1	Air Products & Chem.	12.00%	10.33%	8.77%
2	Amdocs Ltd.	9.50%	4.40%	8.50%
3	Amgen	6.50%	6.87%	7.53%
4	Amphenol Corp.	9.00%	3.00%	7.51%
5	Apple Inc.	14.00%	12.46%	10.67%
6	AT&T Inc.	5.50%	0.29%	5.53%
7	Baxter Int'l Inc.	9.00%	10.00%	9.75%
8	Bristol-Myers Squibb	12.50%	18.40%	8.63%
9	Brown & Brown	10.50%	8.93%	n/a
10	Brown-Forman 'B'	11.00%	3.33%	n/a
11	Church & Dwight	8.00%	9.48%	8.86%
12	Cisco Systems	7.00%	6.18%	5.40%
13	Coca-Cola	6.50%	2.94%	4.81%
14	Colgate-Palmolive	5.00%	5.91%	5.89%
15	Comcast Corp.	13.50%	4.95%	9.70%
16	Commerce Bancshs.	5.00%	-8.70%	n/a
17	Costco Wholesale	9.00%	7.15%	8.40%
18	CVS Health	6.00%	6.34%	5.59%
19	Danaher Corp.	15.00%	13.02%	11.64%
20	Gen'l Mills	3.00%	4.90%	7.50%
21	Hormel Foods	8.50%	2.90%	7.50%
22	Intel Corp.	7.00%	8.62%	7.50%
23	Int'l Flavors & Frag.	8.00%	0.38%	n/a
24	Johnson & Johnson	10.00%	5.08%	5.75%
25	Kellogg	3.00%	1.75%	6.00%
26	Kimberly-Clark	7.00%	6.20%	5.45%
27	Lilly (Eli)	10.00%	13.17%	15.65%
28	Lockheed Martin	8.50%	9.11%	6.93%
29	Marsh & McLennan	9.00%	4.87%	6.00%
30	McCormick & Co.	6.50%	5.00%	5.78%
31	McDonald's Corp.	8.00%	3.88%	7.68%
32	Merck & Co.	9.00%	6.25%	6.74%
33	Microsoft Corp.	15.00%	15.00%	13.71%
34	Northrop Grumman	10.50%	8.62%	n/a
35	Oracle Corp.	10.50%	9.04%	11.00%
36	PepsiCo, Inc.	6.00%	5.48%	5.61%
37	Pfizer, Inc.	8.50%	5.37%	4.29%
38	Procter & Gamble	8.50%	7.72%	7.41%
39	Public Storage	n/a	17.00%	3.45%
40	Texas Instruments	2.50%	10.00%	9.33%
41	Travelers Cos.	9.50%	3.05%	6.66%
42	United Parcel Serv.	6.00%	5.90%	7.77%
43	Verizon Communic.	4.00%	1.23%	3.41%
44	Walmart Inc.	7.50%	6.41%	5.63%
45	Waste Management	5.50%	-1.26%	6.29%

(a) The Value Line Investment Survey (various editions as of Aug. 21, 2020).
(b) www.finance.yahoo.com (retrieved Aug. 24, 2020).
(c) www.zacks.com (retrieved Aug. 24, 2020).

DCF COST OF EQUITY ESTIMATES

		(a)	(a)	(a)
		Earnings Growth		
	Company	**Value Line**	**IBES**	**Zacks**
1	Air Products & Chem.	13.9%	12.2%	10.6%
2	Amdocs Ltd.	11.7%	6.6%	10.7%
3	Amgen	9.2%	9.6%	10.2%
4	Amphenol Corp.	9.9%	3.9%	8.5%
5	Apple Inc.	14.8%	13.3%	11.5%
6	AT&T Inc.	12.5%	7.3%	12.6%
7	Baxter Int'l Inc.	10.2%	11.2%	10.9%
8	Bristol-Myers Squibb	15.5%	21.4%	11.6%
9	Brown & Brown	11.3%	9.7%	n/a
10	Brown-Forman 'B'	12.0%	4.4%	n/a
11	Church & Dwight	9.1%	10.5%	9.9%
12	Cisco Systems	10.1%	9.3%	8.5%
13	Coca-Cola	10.0%	6.5%	8.4%
14	Colgate-Palmolive	7.3%	8.2%	8.2%
15	Comcast Corp.	15.6%	7.1%	11.8%
16	Commerce Bancshs.	6.9%	-6.8%	n/a
17	Costco Wholesale	9.8%	8.0%	9.2%
18	CVS Health	9.1%	9.5%	8.7%
19	Danaher Corp.	15.4%	13.4%	12.0%
20	Gen'l Mills	6.1%	8.0%	10.6%
21	Hormel Foods	10.5%	4.9%	9.5%
22	Intel Corp.	9.5%	11.2%	10.0%
23	Int'l Flavors & Frag.	10.5%	2.9%	n/a
24	Johnson & Johnson	12.7%	7.8%	8.5%
25	Kellogg	6.3%	5.1%	9.3%
26	Kimberly-Clark	9.8%	9.0%	8.3%
27	Lilly (Eli)	11.9%	15.1%	17.5%
28	Lockheed Martin	11.1%	11.7%	9.6%
29	Marsh & McLennan	10.6%	6.5%	7.6%
30	McCormick & Co.	7.8%	6.3%	7.1%
31	McDonald's Corp.	10.5%	6.4%	10.2%
32	Merck & Co.	12.0%	9.3%	9.8%
33	Microsoft Corp.	16.0%	16.0%	14.7%
34	Northrop Grumman	12.3%	10.4%	n/a
35	Oracle Corp.	12.2%	10.8%	12.7%
36	PepsiCo, Inc.	9.0%	8.5%	8.6%
37	Pfizer, Inc.	12.5%	9.4%	8.3%
38	Procter & Gamble	10.9%	10.1%	9.8%
39	Public Storage	n/a	21.1%	7.5%
40	Texas Instruments	5.2%	12.7%	12.0%
41	Travelers Cos.	12.4%	6.0%	9.6%
42	United Parcel Serv.	8.9%	8.8%	10.7%
43	Verizon Communic.	8.3%	5.6%	7.8%
44	Walmart Inc.	9.2%	8.1%	7.3%
45	Waste Management	7.5%	0.7%	8.3%
	Average (b)	**10.4%**	**9.5%**	**9.6%**
	Midpoint (b,c)	**10.4%**	**9.9%**	**9.9%**

(a) Sum of dividend yield (Exh. AMM-21, p. 1) and respective growth rate (Exh. AMM-2
(b) Excludes highlighted figures.
(c) Average of low and high values.

VERIFICATION

The undersigned, Adrien M. McKenzie, being duly sworn, deposes and says he is the President of FINCAP, Inc., that he has personal knowledge of the matters set forth in the forgoing testimony and the information contained therein is true and correct to the best of his information, knowledge and belief after reasonable inquiry.

Adrien M. McKenzie

STATE OF TEXAS)
) Case No. 2020-00174
COUNTY OF TRAVIS)

Subscribed and sworn to before me, a Notary Public in and before said County and State, by BRUCE H. FAIRCHILD this 9th day of November 2020.

Notary Public

BRUCE H FAIRCHILD
Notary ID #131906507
My Commission Expires
February 25, 2023

Notary ID Number: 131906507

My Commission Expires: 2/25/2023

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

Electronic Application Of Kentucky Power Company	)	
For (1) A General Adjustment Of Its Rates For	)	
Electric Service; (2) Approval Of Tariffs And Riders;	)	
(3) Approval Of Accounting Practices To Establish	)	Case No. 2020-00174
Regulatory Assets And Liabilities; (4) Approval Of A	)	
Certificate Of Public Convenience And Necessity,	)	
And (5) All Other Required Approvals And Relief	)	

REBUTTAL TESTIMONY OF

DANA E. HORTON

ON BEHALF OF KENTUCKY POWER COMPANY

REBUTTAL TESTIMONY OF
DANA E. HORTON ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

CASE NO. 2020-00174

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REBUTTAL TESTIMONY OF
DANA E. HORTON ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, POSITION WITH KENTUCKY POWER COMPANY, AND BUSINESS ADDRESS.

A. My name is Dana E. Horton. My position is Director, RTO Markets East for American Electric Power Service Corporation ("AEP"). My business address is One Riverside Plaza, Columbus, Ohio 43215.

II. PURPOSE OF REBUTTAL TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. The purpose of my testimony is to respond, in part, to the testimony of Lane Kollen filed on behalf of the Attorney General of the Commonwealth of Kentucky and the Kentucky Industrial Utility Customers, Inc. (jointly, "AG/KIUC"), in which Mr. Kollen indicates that Kentucky Power Company ("Kentucky Power" or the "Company") has "control" over certain PJM Interconnection LLC ("PJM") costs. Specifically, I address Kentucky Power's lack of control over the process for effecting PJM tariff modifications that could have prevented the default of GreenHat Energy, LLC ("GreenHat") and discuss the facts and circumstances surrounding that default. In this sense, my testimony also addresses the Kentucky Public Service Commission's September 30, 2020 order in Case No. 2020-00034, denying the Company's request to establish a regulatory asset for Kentucky Power's allocation of the GreenHat default charges, which was issued after, and therefore could not have been addressed in, the Company's direct testimony. Importantly, I also explain AEP's efforts to help minimize the financial impact of the GreenHat default on PJM members once the default was known. Kentucky Power Witnesses Kamran Ali and Alex Vaughan respond to Mr. Kollen's testimony as it relates to PJM Network Integration Transmission Service charges.

III. GREENHAT ENERGY, LLC DEFAULT

Q. HOW MUCH OF THE GREENHAT DEFAULT HAS PJM ALLOCATED TO KENTUCKY POWER?

A. As of October 30, 2020, the total amount allocated to Kentucky Power is approximately $348,000. This amount is substantially the entire GreenHat exposure; Kentucky Power estimates that the total to be allocated from the July 2018 default through June 2021 will be approximately $351,000. As I discuss later in this testimony, the Company's allocation could have been upwards of $900,000 absent the favorable settlement AEP and other PJM members achieved to resolve PJM's handling of the first Financial Transmission Rights ("FTR") auction following the GreenHat default. Specifically, PJM originally estimated that the total GreenHat default allocation could have been $250-$300 million higher if required to re-run that auction under the then-existing PJM tariff provisions. AEP and other PJM stakeholders worked quickly and actively to modify the PJM tariff provisions and file them at FERC, and ultimately were able to reach a settlement with several parties to limit the additional exposure from that first auction to no more than $17.5 million.

Q. WHAT HAS THE COMMISSION ORDERED WITH RESPECT TO THE COMPANY'S RECOVERY OF GREENHAT DEFAULT CHARGES?

A. In its order dated September 30, 2020, in Case No. 2020-00034, the Commission denied Kentucky Power's request to establish a regulatory asset to recover the GreenHat default charges. The Commission indicated that an FTR market default that occurred 12 years before the GreenHat default should have been a warning of the GreenHat default. Of most concern, the Commission said, "Kentucky Power's membership in PJM requires diligent participation, including ensuring adequate and appropriate market and credit rules. Kentucky Power and other members failed to fulfill these requirements in the case of the rules that led to the GreenHat default."[1]

Q. PLEASE DISCUSS KENTUCKY POWER'S LEVEL OF CONTROL, AS A PJM MEMBER, OVER THE PJM TARIFF PROVISIONS THAT ESTABLISH MARKET AND CREDIT RULES.

A. Kentucky Power has no direct control over PJM's application of its market and credit rules. And Kentucky Power has limited control over the approval of PJM tariff changes governing market and credit policies. Kentucky Power's participation in the stakeholder process, specifically in relation to PJM tariff changes, is governed by the PJM Operating Agreement ("OA"). Under the OA, any changes to the PJM tariffs is required to be carried out through the process of "sector weighted voting." Sector weighted voting functions by dividing PJM members into five sectors. When a company joins PJM, the company chooses one of five sectors that most aligns with

[1] Case No. 2020-00034, Order at 6 (Sept. 30, 2020).

their business practice: Generation Owners, Transmission Owners, Electric Distributors, End-Use Customers, and Other Suppliers. Each sector must have at least five members in order to cast a vote. AEP is part of the Transmission sector. AEP chose that sector because a) AEP qualifies as a large transmission owner, and b) the transmission sector has the fewest voting members, thereby providing AEP the most voting leverage, albeit still small, possible in the sector voting process. Further, being in the Transmission sector does not limit AEP in advocating for Kentucky Power's customer base in all the PJM stakeholder discussions, including but not limited to those related to transmission, markets, and financial issues.

With regard to sector voting, each sector is allotted 20% of the available vote. This allocation is independent of asset ownership, customer base, or trading volumes. Within a sector, each voting member is then given an equal share of the 20% allotment. The percentage allocation to each member therefore depends on the number of members within the sector. Percentage allocation within the sector also is independent of asset ownership, customer base, or trading volumes. Further, affiliates are not considered when determining vote allocation. Therefore, AEP, as a whole, is allocated only one vote within its sector, despite having 20 subsidiaries in PJM.

AEP represents one of 14 members comprising the Transmission sector. The Transmission sector as a whole is allocated 20% of the available votes, and the 14 members within the Transmission sector are allocated an equal share of that 20%. Thus, AEP ultimately is allocated only about 1.4% of the voting power (20% x 1/14 = 1.4%) among PJM members. This small percentage compares to AEP's approximately 30% of transmission investment, 11,500 MWs of load, and approximately 13,500 MWs of capacity in PJM. However, because a member's asset investment is not considered when determining the percentage allocation of voting power to members, small municipals, co-operatives, and single industrial customers have similar voting power to AEP for items that are submitted for sector voting. It requires a 2/3 majority vote to change any processes related to market and credit policies, which are embedded within the PJM tariff.

Although AEP has limited voting power, it still actively participates in the PJM stakeholder process. Specifically, AEP has regular conversations with PJM Staff at all levels, including the CEO. AEP consistently represents the Transmission sector in the quarterly PJM Liaison Committee meetings with the PJM Board of Managers. It also hosts two weekly meetings with representatives from multiple PJM companies within various sectors in PJM. These meetings are outside the organized PJM stakeholder process, but are instrumental in understanding and developing positions across the sectors. Nevertheless, despite this behind-the-scenes work, when issues come for sector voting, AEP's specific voting power is extremely limited.

Q. IN ITS ORDER IN CASE NO. 2020-00034, THE COMMISSION REFERENCES A 2019 REPORT OF INDEPENDENT CONSULTANTS TO PJM. DOES THAT REPORT INDICATE THAT PJM MEMBERS COULD HAVE ANTICIPATED AND PREVENTED THE GREENHAT DEFAULT?

A. No. According to the 2019 Report of the Independent Consultants cited by the Commission,[2] PJM also hired an independent consultant after the 2007 Tower

[2] *See* Case No. 2020-00034, Order at 6 (Sept. 30, 2020).

Research Capital default. The consultant that reviewed the Tower default made four recommendations to PJM. Although the stakeholders approved one of the recommendations, requiring a shortened time period for settlement of outstanding charges, they did not approve others. However, the 2019 GreenHat Independent Consultants Report uses that example only to show that PJM failed to take credit defaults seriously, and repeatedly did not listen to the advice of those outside the PJM management circle. Most significantly, the 2019 Independent Consultants Report indicates that, "we noted the absence of management recommendations to implement the first three major Market Reform proposals as referred to above. In any case, *we find that PJM management did not go far enough to emphasize these critical policy advances to its stakeholder or its Board.*" (Emphasis in original).[3]

Q. DID THE 2019 CONSULTANTS FIND THAT IMPLEMENTING THE UNADOPTED PROPOSALS WOULD HAVE PREVENTED THE GREENHAT DEFAULT?

A. No. The Independent Consultants did not find that implementing any of the unadopted market reform proposals would have prevented the GreenHat default or mitigated its financial impact on PJM members.

[3] Report of the Independent Consultants on the GreenHat Default at 16, available at https://www.pjm.com/-/media/library/reports-notices/special-reports/2019/report-of-the-independent-consultants-on-the-greenhat-default.pdf.

Q. IF PJM HAD EMPHASIZED A NEED FOR THE ADDITIONAL THREE PROPOSALS, COULD AEP HAVE IMPLEMENTED THEM?

No. As discussed above, AEP has comparatively little voting power. Load Interests control almost 2/3 of the sector-weighted voting compared to AEP's smaller than 1.5% share.

Q. WERE ANY STAKEHOLDERS AWARE OF THE GREENHAT EXPOSURE?

A. Yes. Certain PJM stakeholders that were active in the FTR market became increasingly concerned about the GreenHat position in the FTR market. The Independent Consultants Report (based on confidential interviews and outlined on page 8) shows that five separate PJM market participants communicated with PJM about their concerns over GreenHat. Those communications began as early as January 2017 and continued through April 2018.

Q. WAS KENTUCKY POWER ONE OF THOSE STAKEHOLDERS THAT ALERTED PJM?

A. No. AEP Service Corporation, acting on behalf of Kentucky Power, manages Kentucky Power's FTR position primarily as a hedge against congestion for serving the native load customers. Consequently, AEP Service Corporation does not actively trade in the FTR market and had no knowledge of the GreenHat activities.

Q. DID PJM SHARE ANY OF THESE CONVERSATIONS WITH THE OTHER PJM STAKEHOLDERS, INCLUDING AEP OR KENTUCKY POWER?

A. No.

Q. WHEN DID PJM NOTIFY THE STAKEHOLDER MEMBERSHIP OF THE GREENHAT ISSUE?

A. At the June 21, 2018, Markets Reliability Committee meeting, PJM's Chief Financial Officer, Suzanne Daugherty, "noted that PJM member GreenHat Energy, LLC was in collateral default, and would also be declared in payment default at 5:00 pm June 21, 2018 if they do not pay their currently overdue invoice."[4] This was the first time AEP and Kentucky Power became aware of the GreenHat default.

Q. HOW DID PJM, PJM STAKEHOLDERS, AND KENTUCKY POWER RESPOND?

A. Kentucky Power representatives, along with PJM and the PJM stakeholders, quickly worked through the stakeholder process to develop alternatives to the existing PJM tariff language:

- On July 26, 2018, PJM petitioned FERC for a temporary waiver of certain FTR rules to allow it to liquidate only a portion of the defaulted portfolio. AEP, on behalf of Kentucky Power and other AEP subsidiaries, along with a coalition of other electric utilities, filed in support of PJM's requested waiver.[5]

[4] June 21, 2018, Markets Reliability Committee meeting minutes: https://www.pjm.com/-/media/committees-groups/committees/mrc/20180726/20180726-item-01-draft-minutes-mrc-20180621.ashx

[5] Docket No. ER18-2068, Comments of the PJM Utilities Coalition (August 16, 2016).

- Subsequently, PJM Members approved tariff amendments to allow the temporary suspension of the FTR default liquidation rules. On August 23, 2018, PJM filed those tariff amendments with FERC.[6]
- PJM Members then approved a package of permanent tariff amendments to revise the FTR default liquidation process. On October 1, 2018, PJM filed those tariff amendments with FERC. AEP, on behalf of Kentucky Power and other AEP subsidiaries, along with a coalition of other electric utilities, filed in support of PJM's proposed tariff amendments.[7]

Ultimately, FERC approved PJM's tariff amendments, but denied PJM's initial waiver request.

In response, AEP (on behalf of Kentucky Power and its other subsidiaries) and numerous other parties actively participated in negotiations, and reached a settlement, with two parties who opposed the waiver request. The settlement agreement was approved by FERC. That settlement limited PJM members' total financial exposure from the July 2018 FTR auction to no more than $17.5 million in increased default charges, as compared to PJM's initial estimate of $250-$300 million in increased default charges.

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[6] Docket No. ER18-2289, PJM Financial Transmission Rights Liquidation Revisions (August 23, 2018).

[7] Docket Nos. ER19-19, ER19-23, ER19-24, ER19-25, Comments of the PJM Utilities Coalition (October 22, 2018).

Q. WHAT HAPPENED AFTER THE IMMEDIATE DEFAULT LIQUIDATION ISSUE WAS RESOLVED?

A. As referenced by the Commission in its order in Case No. 2020-00034 and as I mentioned previously, the PJM Board of Managers hired a group of independent consultants to review the events leading up to the default. The independent consultants reported directly to the Board, and issued a 46-page report on March 26, 2019.

Q. WHAT WERE THE FINDINGS FROM THE REPORT?

A. The Independent Consultants found that:

- PJM did not have staff with proper training and credentials in place to monitor the FTR market.
- Even after PJM became aware of the GreenHat potential for default, PJM did not effectively manage the situation.
- PJM did not effectively investigate GreenHat's assurances of creditworthiness and projections of future revenue streams.
- PJM was late to recognize GreenHat as a problem.

Q. WHAT HAS PJM DONE SINCE THE GREENHAT DEFAULT?

A. Several senior executives left PJM after the Independent Consultants Report was issued. The CEO, Chief Financial Officer, Chief Legal Counsel, and others all departed in 2019.

PJM replaced the CEO with someone outside of the PJM environment. PJM has also created a new position of Chief Risk Officer ("CRO"), and hired Nigeria Bloczynski, in an effort to improve PJM's knowledge base in credit markets and PJM's risk management practices. Since the hiring of the CRO, PJM has worked with stakeholders to strengthen the credit rules, increase collateral requirements, and improve the FTR markets in general. Specifically, beginning in May 2019, PJM established the Financial Risk Mitigation Senior Task Force under the purview of the new CRO. This task force posts monthly progress reports at the PJM Members Committee Webinar.[8] AEP's risk management representatives have participated in these meetings. From AEP's perspective, this task force is working to address the process shortfalls that allowed the GreenHat default to occur.

IV. CONCLUSION

Q. DOES THIS CONCLUDE YOUR SUPPLEMENTAL TESTIMONY?

A. Yes, it does.

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[8] September 2020 update: https://www.pjm.com/~/media/committees-groups/committees/mc/2020/20200914-webinar/20200914-item-11l-frmst-report.ashx

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dehorton@aep.com (Principal) (Personally Known)

E-Signature Notary: Brenda Williamson (BW)
November 06, 2020 05:08:48 -8:00 [956684B04A2C] [167.239.2.87]
bgwilliamson@aep.com
I, Brenda Williamson, did witness the participants named above electronically sign this document.

VERIFICATION

The undersigned, Dana E. Horton, being duly sworn, deposes and says he is a Director RTO Regulatory - East for American Electric Power Service Corporation that he has personal knowledge of the matters set forth in the forgoing responses and the information contained therein is true and correct to the best of his information, knowledge and belief after reasonable inquiry.

Dana Horton ____________
Signed on 2020/11/06 05:08:48 -8:00

Dana E. Horton

STATE OF OHIO)

) Case No. 2020-00174

COUNTY OF FRANKLIN)

Subscribed and sworn to before me, a Notary Public in and before said County and State, by 11/06/2020 ____________________, this ____ day of November 2020.

Brenda Williamson ____________________
Signed on 2020/11/06 05:08:48 -8:00

Notary Public

NOTARY PUBLIC STATE OF OHIO

Brenda G. Williamson
Commission # 2016-RE-579446
Electronic Notary Public
State of Ohio
My Comm Exp. Apr 25, 2021

Notary Stamp 2020/11/06 06:08:48 PST 956684B04A2C

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

Electronic Application Of Kentucky Power Company	)	
For (1) A General Adjustment Of Its Rates For	)	
Electric Service; (2) Approval Of Tariffs And Riders;	)	
(3) Approval Of Accounting Practices To Establish	)	Case No. 2020-00174
Regulatory Assets And Liabilities; (4) Approval Of A	)	
Certificate Of Public Convenience And Necessity;	)	
And (5) All Other Required Approvals And Relief	)	

REBUTTAL TESTIMONY OF

KAMRAN ALI

ON BEHALF OF KENTUCKY POWER COMPANY

REBUTTAL TESTIMONY OF
KAMRAN ALI ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

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KAMRAN ALI ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Kamran Ali. My business address is 8500 Smiths Mill Road, New Albany, Ohio 43054.

Q. BY WHOM ARE YOU EMPLOYED AND WHAT IS YOUR POSITION?

A. I am an employee of American Electric Power Service Corporation ("AEPSC") as Managing Director of Transmission Planning. AEPSC supplies engineering, financing, accounting, planning, advisory, and other services to the subsidiaries of the American Electric Power ("AEP") system, one of which is Kentucky Power Company ("Kentucky Power" or the "Company").

Q. DID YOU OFFER DIRECT TESTIMONY IN THIS PROCEEDING?

A. No.

II. PURPOSE OF REBUTTAL TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. The purpose of my rebuttal testimony is to:

- Respond to the recommendation by Attorney General/Kentucky Industrial Utility Customers, Inc. ("AG/KIUC") witness Lane Kollen that the Public Service Commission of Kentucky ("Commission") deny the Company's request to continue recovery of incremental PJM Load Serving Entity ("LSE") Open Access

Transmission Tariff ("OATT") net expenses through the Company's Tariff PPA (Power Purchase Adjustment);

- Address why the Company's PJM LSE OATT expenses are increasing; and
- Support the prudence and necessity of the recovery of the current and incremental PJM LSE OATT expenses through Tariff PPA.

III. INCREMENTAL LSE OATT EXPENSES

Q. ON PAGE 54 OF HIS TESTIMONY, MR. KOLLEN RECOMMENDS THAT THE COMMISSION DENY RECOVERY THROUGH TARIFF PPA OF ANY INCREMENTAL LSE OATT NET EXPENSES. DO YOU AGREE WITH HIS RECOMMENDATION?

A. No, I do not. The majority of the Company's LSE OATT expenses are comprised of Network Integration Transmission Service ("NITS") costs. NITS costs are collectively significant, volatile or variable, and largely outside Kentucky Power's control. The continued recovery of PJM LSE OATT costs through Tariff PPA is reasonable and appropriate. Company Witness Vaughan also addresses this issue, including the significance of PJM LSE OATT expense, in his Direct and Rebuttal Testimony.

Q. WHAT ARE PJM NITS CHARGES?

A. NITS charges represent the necessary costs incurred by transmission owners to maintain the reliability of the transmission grid and ensure equal access by all users of the transmission system. NITS charges in the AEP Zone are derived from the transmission investments of all transmission owners in the AEP Zone.

Q. AS YOU MENTIONED EARLIER, COMPANY WITNESS VAUGHAN'S TESTIMONY EXPLAINS THAT THE COMPANY'S PJM LSE OATT EXPENSE IS INCREASING. WHY IS THE NITS PORTION OF THAT EXPENSE INCREASING?

A. The increase in NITS charges is being driven by investment in transmission infrastructure. In recent history, transmission investment was focused on system needs arising from retirement of generation due to environmental regulations. In addition, the transmission system requires substantial investment to address aging infrastructure, cyber and physical security threats, and modernization of protection and control equipment. This requires infrastructure improvements occurring both within KPCo's service territory and the remainder of the AEP Zone. The costs associated with these investments are billed to the AEP Zone and charged to KPCo through the monthly PJM bill and the AEP Transmission Agreement.

Q. IS THE NEED FOR TRANSMISSION INFRASTRUCTURE INVESTMENT UNIQUE TO KENTUCKY POWER, AEP, OR PJM?

A. No. Industry wide, utilities are investing in the transmission system to meet the above-described needs. Nationally, transmission investment has increased over the past 10 years. The Company expects robust levels of investment will continue.

Q. PLEASE ELABORATE ON YOUR STATEMENT THAT NITS COSTS ARE VOLATILE OR VARIABLE.

A. NITS costs are volatile or variable because they are incurred in connection with required transmission system investments to address (a) the condition of the assets, which includes many assets that exceed their expected or designed life; (b) the performance of the infrastructure; (c) cyber and physical security threats; (d) modernization of protection and control equipment; (e) obsoleteness of major equipment necessary for safely, securely, efficiently, and reliably operating the grid; and (f) changes in industry regulations. Additionally, these costs, during any given period, are subject to potentially significant changes due to market and economic conditions, public policy, North American Electric Reliability Corporation ("NERC"), Federal Energy Regulatory Commission ("FERC"), environmental, and state regulatory requirements and other factors that can be unpredictable. For instance, in 2012, PJM initiated $3 billion in transmission investment to mitigate the impact of 7,500 MW of generation retirement in the Ohio Valley due to implementation of federal Mercury and Air Toxics Standards. The scope and scale of transmission investment can be volatile due to items such as this federal action, which cannot be forecasted with certainty.

The collective impact of these drivers is to cause varying levels of investment (sometimes increasing, and sometimes decreasing) over time in each AEP operating and transmission company's jurisdiction, including Kentucky Power's.

Q. ARE NITS COSTS OUTSIDE OF THE COMPANY'S CONTROL?

A. Yes, they are largely outside of Kentucky Power's control. Although Kentucky Power commits significant resources to reduce safety risks, maintain transmission assets consistent with industry and PJM standards, and plan capital investment to increase reliability performance, many of the drivers of transmission investment described above are largely or entirely outside of the control of Kentucky Power and other transmission owners. Each transmission owner in the AEP Zone has an obligation to ensure capital investments are prudent and necessary to maintain the reliability of the transmission grid. The FERC-approved AEP Transmission Agreement, to which KPCo is a member, requires "[e]ach member [to] maintain its respective portion of the Bulk Transmission System, together with all associated facilities and appurtenances, in a suitable condition of repair at all times in order that said system will operate in a reliable and satisfactory manner." Consistent with that obligation, the Company will continue to evaluate, prioritize, and select the Supplemental Projects that are necessary to provide a reliable transmission grid within its service territory. Although Kentucky Power has some control over its own specific asset replacement if that replacement is made before an asset's failure, many of the underlying drivers of asset performance such as equipment age, equipment abnormalities, and environmental conditions are also outside of the Company's control.

Q. IN HIS REBUTTAL TESTIMONY, COMPANY WITNESS VAUGHAN TESTIFIES THAT KENTUCKY POWER ALSO HAS NO CONTROL OVER ITS AFFILIATES' TRANSMISSION SPENDING. DO YOU AGREE?

A. I absolutely agree with Mr. Vaughan and will elaborate from my perspective within AEPSC's Transmission Planning organization. Kentucky Power does not have control over costs that any other transmission owner in the AEP zone incurs, just as other transmission owners do not have control over the Company's transmission costs. The fact that the other transmission owners may be Kentucky Power affiliates does not change the obligation that each transmission owner has to pursue prudent projects needed to address safety, security, efficiency as well as asset condition, performance, and risk to provide reliable services in that owner's service territory. Nor does those transmission owners' status as affiliates provide Kentucky Power with control over what those companies' needs are or what projects are needed to meet those needs.

These transmission projects are driven by the underlying need for infrastructure improvements and each regional transmission organization ("RTO") transmission owner's obligation to provide safe, adequate, and reliable transmission service and facilities in accordance with Good Utility Practice[1] requirements that have long been the foundation for utility planning and operations and continue to be imposed on RTO transmission owners by FERC. Ultimately, AEP's structure does not supplant the respective obligations of the RTO transmission owners to fulfill their respective public utility obligations to serve. Rather, AEP's structure facilitates the planning process and helps AEP and Kentucky Power achieve the joint transmission system benefits the entire RTO system was created to foster.

IV. CONCLUSION

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes, it does.

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[1] FERC has defined "Good Utility Practice" in Section 1.14 of the pro forma Open Access Transmission Tariff in Order 888 as: "Any of the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather to be acceptable practices, methods, or acts generally accepted in the region."

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I, Brenda Williamson, did witness the participants named above electronically sign this document.

VERIFICATION

The undersigned, Kamran Ali, being duly sworn, deposes and says he is a Managing Director of Transmission Planning for American Electric Power Service Corporation that he has personal knowledge of the matters set forth in the forgoing responses and the information contained therein is true and correct to the best of his information, knowledge and belief after reasonable inquiry.

Kamran Ali
Signed on 2020/11/02 07:02:46 -8:00
2A131361D1A7

Kamran Ali

STATE OF OHIO)
) Case No. 2020-00174
COUNTY OF FRANKLIN)

Subscribed and sworn to before me, a Notary Public in and before said County and State, by Kamran Ali, this ____ day of November 2020.

11/02/2020

Brenda Williamson
Signed on 2020/11/02 07:02:46 -8:00
997D4526A798

Notary Public

NOTARY PUBLIC STATE OF OHIO
Brenda G. Williamson
Commission # 2016-RE-579446
Electronic Notary Public
State of Ohio
My Comm Exp. Apr 25, 2021
Notary Stamp 2020/11/02 08:02:46 PST 997D4526A798

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

Electronic Application Of Kentucky Power Company	)	
For (1) A General Adjustment Of Its Rates For	)	
Electric Service; (2) Approval Of Tariffs And Riders;	)	
(3) Approval Of Accounting Practices To Establish	)	Case No. 2020-00174
Regulatory Assets And Liabilities; (4) Approval Of A	)	
Certificate Of Public Convenience And Necessity,	)	
And (5) All Other Required Approvals And Relief	)	

REBUTTAL TESTIMONY OF

KELLY D. PEARCE

ON BEHALF OF KENTUCKY POWER COMPANY

REBUTTAL TESTIMONY OF
KELLY D. PEARCE ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

CASE NO. 2020-00174

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REBUTTAL TESTIMONY OF
KELLY D. PEARCE ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Kelly D. Pearce, and my business address is 1 Riverside Plaza, Columbus, Ohio, 43215.

Q. BY WHOM ARE YOU EMPLOYED AND WHAT IS YOUR POSITION?

A. I am employed by American Electric Power Service Corporation ("AEPSC") as Managing Director of Transmission Asset Strategy and Policy ("TASP"). AEPSC supplies engineering, financing, accounting, planning, advisory, and other services to the subsidiaries of the American Electric Power ("AEP") system, one of which is Kentucky Power Company ("Kentucky Power" or the "Company").

Q. PLEASE BRIEFLY DESCRIBE THE TRANSMISSION ASSET STRATEGY AND POLICY DEPARTMENT AND YOUR PRIMARY AREAS OF RESPONSIBILITY AS MANAGING DIRECTOR, TRANSMISSION ASSET STRATEGY AND POLICY.

A. The TASP department is part of the AEP Transmission business unit ("Transmission"). Among its activities, TASP (a) works with AEP operating companies to develop and provide transmission strategy and policy positions, (b) oversees reporting needs for the AEP transmission assets for the AEP transmission-only companies and the AEP operating companies at the regional transmission organizations ("RTOs"), the Federal Energy Regulatory Commission ("FERC") and state regulatory commissions, and (c) represents AEP in various industry organizations.

My current responsibilities include providing Transmission-related support for the AEP operating companies and transmission-only companies ("Transcos") in their respective state and federal jurisdictions.

Q. PLEASE BRIEFLY DESCRIBE YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND

A. I received a Bachelor of Science degree in Mechanical Engineering from Oklahoma State University in 1984. I received Master of Science and Doctor of Philosophy degrees in Nuclear Engineering from the University of Michigan in 1986 and 1991 respectively. I received a Master of Science in Industrial Administration degree from Carnegie Mellon University in 1994.

From 1986 to 1988, I worked for a subsidiary of Olin Corporation. From 1991 to 1996, I worked for the United States Department of Energy within the Office of Fossil Energy. My responsibilities included serving as a Contracting Officer's Representative in the oversight and administration of government-funded research of advanced generation and environmental remediation technologies and projects. I also supported strategic studies for deployment and commercialization of these technologies, as well as administration and support of government research and development solicitations.

In 1996, I joined AEPSC as a Rate Consultant I in the Regulatory Services department. In 2001, I was promoted to Senior Regulatory Consultant. My responsibilities included preparation of class cost-of-service studies and rate design for AEP operating companies and the preparation of special contracts and regulated pricing for retail customers. In 2003, I transferred to Commercial Operations within AEPSC as Manager of Cost Recovery Analysis. In 2007, I was promoted to Director of Commercial Analysis. During this period, I was responsible for analyzing the financial impacts of Commercial Operations related activities. I also supported settlement of AEP's generation pooling agreements among AEP's operating companies. In 2010, I transferred to Regulatory Services as Director, Contracts and Analysis. In April 2018, I was promoted to Managing Director, Contracts Analysis and FERC Regulatory. In September 2018, I transferred to Transmission in my current position. I am a registered Professional Engineer in Ohio and West Virginia.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE ANY REGULATORY COMMISSIONS?

A. Yes. I testified before this Commission in Case No. 2014-00225. I testified before the Virginia State Corporation Commission in Case No. PUE-2001-00306, before the Public Utilities Commission of Ohio in Case Nos. 11- 346-EL-SSO, *et al*., 10-2929-EL-UNC, and 14-1693-EL-RDR, *et al*., before the Indiana Commission in Cause No. 43992, before the Corporation Commission of Oklahoma in Cause No. 201700267, and before the Public Utility Commission of Texas in Docket No. 47461. I have also submitted testimony in various dockets, including to the Federal Energy Regulatory Commission in Docket No. ER13-539-000.

Q. DID YOU OFFER DIRECT TESTIMONY IN THIS PROCEEDING?

A. No.

II. PURPOSE OF REBUTTAL TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. The purpose of my rebuttal testimony is as follows:

- I respond to the Kentucky Attorney General and Kentucky Industrial Utility Customers, Inc. ("AG/KIUC") witness Mr. Stephen J. Baron's testimony on transmission issues.
- I demonstrate that Kentucky Power's participation in the AEP Transmission Agreement benefits Kentucky Power's customers; and
- I respond to Mr. Baron's suggestion that Kentucky Power should become a standalone member of PJM.

III. COST ALLOCATION AND THE AEP TRANSMISSION AGREEMENT

Q. ON PAGE 13, LINES 12 THROUGH 14 OF MR. BARRON'S TESTIMONY, HE QUESTIONS KENTUCKY POWER'S PARTICIPATION IN THE AEP TRANSMISSION AGREEMENT. PLEASE DESCRIBE THE AEP TRANSMISSION AGREEMENT.

A. The AEP Transmission Agreement is a FERC-approved agreement that governs the allocation of revenues and expenses among the AEP member transmission companies. It provides for the equitable sharing among the members of the costs incurred by the members in connection with the ownership and use of the transmission system.

Q. DOES THE TRANSMISSION AGREEMENT PROVIDE BENEFITS TO KENTUCKY POWER?

A. Yes. AEP developed an extensive transmission system that serves as the medium for integrating the power supply resources of the member companies. The PJM East Zone system stretches from the southeastern shores of Lake Michigan through northern Indiana and Ohio to the mountains of Kentucky, Tennessee, Virginia, and West Virginia. AEP pioneered extra-high-voltage ("EHV") transmission as a means of achieving the advantages of large-scale system integration and the ability to move power to widely separated load areas via high voltage and EHV transmission.

Q. WHAT BENEFITS DOES KENTUCKY POWER GET FROM THE TRANSMISSION AGREEMENT?

A. A significant benefit that Kentucky Power receives from its participation in the transmission agreement is the allocation of its costs as a PJM Load Serving Entity ("LSE"). PJM allocates the cost of Network Integrated Transmission Service ("NITS") among LSEs in the AEP zone based on each LSE's contribution to the single highest hourly peak of the zone over a 12-month period ("1 Coincident Peak" or "1CP"). Under the Transmission Agreement, the total NITS charge to the members is reallocated among the members based on the average of each member's average contribution to the monthly peaks over a 12-month period ("12 Coincident Peaks" or "12CP"). Mr. Barron appears to agree with the Company, for example on page 19, lines 7 through 11, regarding this difference in the allocation.

Q. WHY DOES PJM ALLOCATE COSTS USING 1CP?

A. PJM has used a simplified approach in terms of allocating transmission costs based on the single highest hourly demand on the system. One reasoning is that the system overall is designed to accommodate this maximum peak, and so 1CP is selected to identify each LSE's contribution to it.

Q. WHY IS 12CP USED IN THE TRANSMISSION AGREEMENT?

A. There is generally no "perfect" allocation method. In the case of 12CP, it is reasonable because it considers loads' use of the transmission system based on more than a single hour. Loads use the transmission system throughout the year and it is just and reasonable that that is reflected in what they are charged. Second, use of only 1CP may incentivize gaming in the sense that LSEs may attempt to reduce their load during that 1CP and shift cost to other LSEs. I distinguish gaming from legitimate load management activities. Third and most important, use of the 12CP tends to be less volatile than 1CP. Each member's contribution to the 12CP is going to tend to change less from year to year than their 1CP contribution. Use of the 12CP thus helps the companies and their customers better manage their costs with reduced volatility. Importantly, in this case, the 12CP method benefits all the members of the Transmission Agreement, including Kentucky Power.

Q. WHAT IMPACT DOES SEASONAL PEAK VARIATION HAVE ON THIS VOLATILITY?

A. AEP companies are geographically diverse. Some of the AEP companies tend to be summer-peaking, while others are winter-peaking, including Kentucky Power. If AEP used the 1CP method, individual AEP companies would be subject to more volatile swings in expenses. Their cost would fluctuate significantly depending on whether the 1CP occurred in the summer or the winter. The 12CP method results in more stable cost sharing among the AEP companies than other alternatives.

Q. YOU MENTIONED EARLIER THAT THE 12CP ALLOCATION BENEFITS KENTUCKY POWER. HAVE YOU PERFORMED AN ANALYSIS THAT

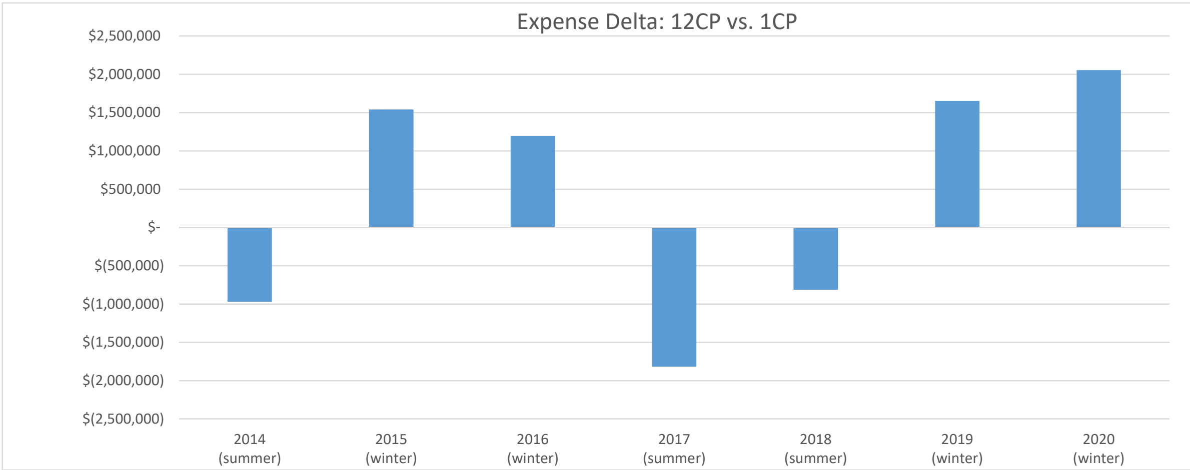
COMPARES KENTUCKY POWER'S EXPENSES USING THE 12CP METHOD TO THE 1CP METHOD?

A. Yes. I looked at the impacts on the peaks for the last seven years in the AEP zone. Over that period, Kentucky Power's allocation of the NITS cost based on 12CP varied from 5.66% to 6.53%, with a standard deviation -- a measure of volatility with the higher number indicating more volatility -- of 0.41%. Under the 1CP method over the same period, Kentucky Power's allocation of total NITS cost would have varied from 5.20% up to 7.71% with a standard deviation of 1.13%. The 1CP would have resulted in much more volatility for Kentucky Power over the period, with its NITS responsibility changing as much as 2.51% from one year to another. By contrast, the costs allocated using 12CP varied only 0.87% or by a factor of almost three less.

Q. WOULD KENTUCKY POWER'S TOTAL NITS COST RESPONSIBILITY HAVE BEEN LOWER OVER THIS SEVEN-YEAR PERIOD USING 1CP?

A. Yes. Figure KDP-1 shows the increases (2015, 2016, 2019, and 2020) and decreases (2014, 2017, and 2018) in NITS expense that would have been paid by Kentucky Power if 1CP had been used in lieu of the 12CP allocation methodology specified by the Transmission Agreement. As shown in Figure KDP-1, some years, Kentucky Power would have paid more and some years less using 1CP instead of 12CP. But over the 7-year period, Kentucky Power customers would have paid approximately $2.06 Million more using 1CP than they paid under the 12CP method of allocation.

Figure KDP-1



Note: Positive values in Figure KDP-1 indicate an increased Kentucky Power expense using 1CP instead of 12CP, while lower numbers indicate a reduced Kentucky Power expense using 1CP.

Q. DOES THE AEP TRANSMISSION AGREEMENT ALLOW MEMBERS TO WITHDRAW FROM THE AGREEMENT?

A. Section 9.3 of the AEP Transmission Agreement allows any member to withdraw from the agreement upon at least three years' prior written notice to the other members and the agent.

Q. IN YOUR OPINION, SHOULD KENTUCKY POWER GIVE THIS NOTICE TO LEAVE THE TRANSMISSION AGREEMENT?

A. Due to the benefits described above, no. As I have discussed, doing so would subject Kentucky Power and its customers to greater volatility in NITS costs.

Q. ON PAGE 13, LINE 12 OF MR. BARRON'S TESTIMONY, HE SUGGESTS THAT KENTUCKY POWER SHOULD SEEK TO HAVE ITS SERVICE TERRITORY BECOME ITS OWN LOAD ZONE IN PJM. DOES THE PJM

CONSOLIDATED TRANSMISSION OWNERS AGREEMENT ("CTOA") ALLOW FOR THE ESTABLISHMENT OF ADDITIONAL ZONES?

A. No. As shown in the Company's response to AG/KIUC First Set of Data Requests (AG_KIUC-1-052) the PJM CTOA Section 7.4 provides the following:

For purposes of developing rates for service under the PJM Tariff, transmission rate Zones smaller than those shown in Attachment J to the PJM Tariff, or subzones of those Zones, shall not be permitted within the current boundaries of the PJM Region; provided, however, that additional Zones may be established if the current boundaries of the PJM Region is expanded to accommodate new Parties to this Agreement.

The CTOA does not allow for the establishment of a Kentucky Power-specific load zone.

Q. SETTING ASIDE THE CTOA, WOULD THIS ACTION BENEFIT KENTUCKY POWER?

A. I do not believe it would. Investment among the various AEP Companies, including Kentucky Power, varies over time for reasons explained by Company Witness Ali.

IV. CONCLUSION

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes, it does.

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bgwilliamson@aep.com
I, Brenda Williamson, did witness the participants named above electronically sign this document.

VERIFICATION

The undersigned, Kelly D. Pearce, being duly sworn, deposes and says he is a Managing Director of Transmission Asset Strategy and Policy for American Electric Power Service Corporation that he has personal knowledge of the matters set forth in the forgoing responses and the information contained therein is true and correct to the best of his information, knowledge and belief after reasonable inquiry.

C5526C689FDA
Kelly D Pearce
Signed on 2020/11/06 06:04:25 -8:00
____
Kelly D. Pearce

STATE OF OHIO)
) Case No. 2020-00174
COUNTY OF FRANKLIN)

Subscribed and sworn to before me, a Notary Public in and before said County and State, by 11/06/2020 ____________________, this _____ day of November 2020.

84F6E8A28DE2
Brenda Williamson
Signed on 2020/11/06 06:04:25 -8:00
____
Notary Public

NOTARY PUBLIC
STATE OF OHIO
Brenda G. Williamson
Commission # 2016-RE-579446
Electronic Notary Public
State of Ohio
My Comm Exp. Apr 25, 2021
Notary Stamp 2020/11/06 07:04:25 PST 84F6E8A28DE2

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

Electronic Application Of Kentucky Power Company	)	
For (1) A General Adjustment Of Its Rates For	)	
Electric Service; (2) Approval Of Tariffs And Riders;	)	
(3) Approval Of Accounting Practices To Establish	)	Case No. 2020-00174
Regulatory Assets And Liabilities; (4)Approval Of A	)	
Certificate Of Public Convenience And Necessity;	)	
And (5) All Other Required Approvals And Relief	)	

REBUTTAL TESTIMONY OF

ALEX E. VAUGHAN

ON BEHALF OF KENTUCKY POWER COMPANY

REBUTTAL TESTIMONY OF
ALEX E. VAUGHAN
ON BEHALF OF KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

CASE NO. 2020-00174

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ALEX E. VAUGHAN ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS AND PRESENT POSITION.

A. My name is Alex E. Vaughan, and I am employed by American Electric Power Service Corporation ("AEPSC") as Director, Regulated Pricing and Renewables. My business address is 1 Riverside Plaza, Columbus, Ohio 43215. AEPSC is a wholly-owned subsidiary of American Electric Power Company, Inc. ("AEP"), the parent Company of Kentucky Power Company (the "Company" or "Kentucky Power").

Q. ARE YOU THE SAME ALEX E. VAUGHAN WHO OFFERED DIRECT TESTIMONY IN THIS PROCEEDING?

A. Yes.

II. PURPOSE OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. The purpose of my rebuttal testimony is to respond to intervenor testimony regarding cost of service, rate design, cost allocation, and the Company's proposed tariffs. In particular, I am responding to intervenor testimony on the following subjects:

- The utilization of capitalization rather than rate base to determine the return on component of the Company's rates;
- Cash working capital;

- Increasing the Rockport deferral to reflect the Company's cost of service adjustment;
- The Mitchell coal stock adjustment's effect on the proposed capital structure;
- The Capacity Charge;
- PJM LSE OATT expense and the continued need for tracking;
- Unprotected excess ADFIT offset implementation;
- Residential tariff basic service charge;
- Various net metering issues; and
- The COGEN/SPP tariffs and PURPA reform.

Q. ARE YOU SPONSORING ANY REBUTTAL EXHIBITS OR SCHEDULES?

A. Yes, I am sponsoring the following exhibits:

- **Exhibit AEV-R1** – OATT Adjustment Update
- **Exhibit AEV-R2** – EE Investment Payback Example
- **Exhibit AEV-R3** – KY Basic Service Charge Comparison
- **Exhibit AEV-R4** – NMS System Market Value
- **Exhibit AEV-R5** – NMS II Updated Avoided Cost Rate Residential
- **Exhibit AEV-R6** – NMS II Updated Avoided Cost Rate Commercial
- **Exhibit AEV-R7** – NMS vs Standard Class Cost of Service Example

III. SUMMARY OF REBUTTAL TESTIMONY

Q. PLEASE SUMMARIZE YOUR REBUTTAL TESTIMONY AND RECOMMENDATIONS.

A. The following is a summary of my rebuttal recommendations:

- The AG/KIUC's recommendation to use rate base for the return on component of the Company's base rates should not be accepted, the Company's proposed capitalization amounts are properly calculated and are reasonable for calculating the return on component of base rates;

- AG/KIUC witness Kollen's proposed capitalization adjustments, including cash working capital, are unnecessary based on the way the Company calculated its proposed base rate capitalization level and should not be accepted;
- AG/KIUC witness Kollen's proposed 10 year recovery period for Rockport unit 2 SCR depreciation expense is not reasonable and should not be accepted, rather a shorter recovery period of 4 years as proposed by the Company in its rebuttal may be reasonable for rate increase mitigation purposes;
- The Company's proposed base amount of PJM LSE OATT expenses and tracking of incremental increases or decreases to that amount should continue through Tariff PPA. If the Commission does not approve this treatment, the otherwise ordered increase in this case should be increased as described in my rebuttal testimony for the new AEP Zone OATT rates on file at the FERC;
- AG/KIUC witness Kollen's proposal regarding the Company's capacity charge rider is unreasonable, is in violation of the Commission approved settlement agreement in Case No. 2004-00420 and should not be approved. The Company's proposal regarding the capacity charge continues to be conditioned upon the Company receiving its requested base rate increase;
- The Company's rate design including the proposed residential basic service charge of $17.50 is supported from a cost of service perspective, a policy perspective, and by comparison to the other electric service providers in Kentucky. As such it should be approved by the Commission;

- The Company's proposed Tariff NMS II and its avoided cost rates for excess generation as modified in my rebuttal testimony should be approved as a successor to Tariff NMS. NMS II provides the "dollar value" financial compensation to eligible customer generators contemplated in KRS 278.465 and 278.466, which replaces the former 1 to 1 volumetric netting/compensation under the previously applicable statute. NMS II is properly designed, supported by the Company's cost of service and participation in the PJM RTO, and is just and reasonable; and
- The Company's COGEN/SPP tariffs should be updated as I describe in my rebuttal testimony for the recent FERC order 872.

IV. CAPITALIZATION VERSUS RATE BASE

Q. DO YOU AGREE WITH AG/KIUC WITNESS KOLLEN (AT PAGES 8-12) THAT RATE BASE IS "SUPERIOR" TO CAPITALIZATION FOR DETERMINING THE RETURN ON COMPONENT OF BASE RATES?

A. No, not in the Company's case. As evidence for his argument, Mr. Kollen cites the Commission's recent approvals of rate base for Duke Energy Kentucky and Louisville Gas & Electric/Kentucky Utilities Company ("LG&E/KU"). Both companies are electric and gas utilities that proposed forward looking test years. In those cases, I would agree that rate base is superior from a case preparation and auditability standpoint. It would be more difficult to use capitalization and adjust out the various gas utility assets and layer on the forward-looking forecast adjustments. The Company, however, is a single jurisdiction, electric-only utility proposing a historic test year in this case. The fact patterns of those cases are distinguishable and inapplicable to the Company's current case. Capitalization is a reasonable measure of the return on component of the base rate revenue requirement, as the Commission has repeatedly recognized since at least 2009.[1]

Q. WHAT IS THE RIGHT MEASURE FOR DETERMINING THE RETURN ON COMPONENT OF THE BASE RATE REVENUE REQUIREMENT?

A. The correct measure is one that includes all of the utility's assets that have been capitalized. This objective can be accomplished through either capitalization or rate base. When done correctly, the two methods should reach materially the same result. That being said, the Company strongly objects to Mr. Kollen's removal of the prepaid pension and OPEB assets from the Company's return on calculation. This proposal is improper as further discussed by Company Witness Whitney.

Q. DOES MR. KOLLEN'S CASH WORKING CAPITAL ARGUMENT (ON PAGE 12) HAVE ANY MERIT?

A. No, Mr. Kollen's assertion that "cash working capital ('CWC') should be calculated using the lead/lag approach, or alternatively, set to 0" is without merit. Mr. Kollen seems to base this assertion on his assumption that a lead/lag study would produce $0 or less of CWC for inclusion in rate base because the Company sells its receivables by factoring them to AEP Credit, Inc. However, Mr. Kollen's position misses the point that because the Company proposed to use end of period capitalization as the basis for the return on component of its base rate revenue requirement, the base revenue requirement reflects the Company's actual working capital needs as of the end of the test year. There is no estimate of cash working capital implicitly included in the Company's request that requires adjustment.

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[1] Case No. 2017-00179, Order (Jan. 18, 2018); Case No. 2014-00396, Order (Jun. 22, 2015); Case No. 2009-00459, Order (Jun. 28, 2010).

Q. DO CUSTOMERS ALREADY RECEIVE THE COST OF SERVICE BENEFIT OF THE COMPANY FACTORING ITS RECEIVABLES?

A. Yes they do, as the factored receivables balance is included in the Company's capital structure for purposes of calculating the Company's weighted average cost of capital ("WACC"). If Mr. Kollen's recommendations to switch from capitalization to rate base and to impute a lead/lag study on the Company's cost of service by reducing CWC to zero are accepted, then the accounts receivable financing amount should be removed from the Company's capital structure, resulting in a roughly 12 basis point increase in the WACC. To not do so would wrongfully cause a reduction in the Company's capitalization (rate base) while still providing a benefit to customers through the capital structure for the same item and thus would be double counting it.

Q. WHY DID THE COMPANY NOT CONDUCT A LEAD/LAG STUDY?

A. As stated above, the Company did not conduct and lead/lag study and is not proposing rate base in this case, it utilized capitalization as the measure for the return on component of its base rate revenue requirement. A lead/lag study is not necessary under the capitalization methodology. Additionally, lead/lag studies are time consuming and costly, as the Company would have had to contract with an outside consultant to produce one. Moreover, it would be fundamentally unfair to retroactively require the Company to perform a lead/lag study given the Commission's repeated acceptance of the Company's use of capitalization.

Q. DOES THE COMPANY AGREE WITH AG/KIUC WITNESS KOLLEN'S PROPOSED CAPITALIZATION ADJUSTMENTS ON PAGE 26 OF HIS TESTIMONY?

A. No, it does not. Again, because the Company has proposed to use capitalization as the basis for the return on component of its base rate revenue requirement, any non-financed items have already been excluded from the Company's request. Any non-utility items or regulatory asset balances earning a return elsewhere in the Company's rates were removed in Section V, Schedule 3. The same is true for Mr. Kollen's proposals regarding accounts payables balances in CWIP and prepayments. No further adjustments to the Company's capitalization are required, as also discussed by Company witness Whitney.

V. <u>ROCKPORT UPA COST OF SERVICE ITEMS</u>

Q. DOES THE COMPANY AGREE WITH AG/KIUC WITNESS KOLLEN'S PROPOSAL REGARDING THE ROCKPORT UPA BASE RATE DEMAND EXPENSE ON PAGE 33 OF HIS DIRECT TESTIMONY?

A. Yes, due to the various current economic issues in the Company's service territory the Company agrees that this is a reasonable mitigation proposal in this case. The $1,695,513 included in adjustment W47 would be added to the existing Rockport deferral regulatory asset in 2021 and $1,554,220 (eleven-twelfths of the annual amount included in adjustment W47) would be added to the Rockport deferral regulatory asset in 2022. The Rockport deferral regulatory asset, including these additional amounts, would accrue a carrying charge at the Company's approved WACC until it is fully recovered, consistent with the Commission approved

Settlement Agreement in Case No. 2017-00179. As discussed in the direct testimony of Company Witness West, the Company is requesting to amortize and recover the Rockport deferral regulatory asset as of December 8, 2022 (when the Rockport UPA terminates) over 5 years through Tariff P.P.A. beginning in December 2022, consistent with the approved Settlement Agreement filed in Case No. 2017-00179.

Q. PLEASE ADDRESS AG/KIUC WITNESS KOLLEN'S PROPOSAL BEGINNING ON PAGE 49 OF HIS DIRECT TESTIMONY REGARDING THE ROCKPORT UNIT 2 SCR DEPRECIATION EXPENSE.

A. Mr. Kollen's proposal is contrary to the plain language of KRS 278.183, which provides for current recovery of these costs. Nor is a 10-year recovery period appropriate, in any event, because extending the recovery of Rockport unit 2 SCR depreciation expense currently billed and recovered through the Company's Environmental Surcharge ("ES") could negatively impact Kentucky Power's cash flow and credit metrics, and would accrue a decade worth of carrying charges to be paid by customers.

Nonetheless, in the interest of mitigating the overall rate increase in this case, the Company would be willing to accept a 4-year recovery period for the Rockport unit 2 SCR depreciation expense. Specifically, the Company would agree to defer a portion of the Rockport unit 2 SCR depreciation expense that will be billed to the Company through the UPA for January 2021 through December 2022. A simple way to effectuate this would be to defer half of the billed Rockport unit 2 SCR depreciation expense recoverable from Kentucky retail customers through the

ES to reflect 4 year recovery of the roughly 2 years of billed expenses. A regulatory asset would need to be approved and created for the ES deferral amounts, and those deferrals would need to earn a WACC carrying charge while the Company is carrying them on its books. The regulatory asset would then be amortized over 24 months beginning January 2023 through the ES for collection from customers. This mitigation proposal would reduce the net increase in total rates resulting from this case by approximately $10 million annually.

Q. PLEASE ADDRESS AG/KIUC WITNESS KOLLEN'S PROPOSAL ON PAGES 55 THROUGH 58 REGARDING THE TERMINATION OF THE COMPANY'S CAPACITY CHARGE.

A. As I discussed in my Direct Testimony at page 30, the Company proposed to forgo collection of the $6.2 and $5.79 million (2021 and 2022 respectively) it is entitled to collect through the Capacity Charge tariff as a way to mitigate the base rate increase requested in this case. That proposal was conditioned upon the Company receiving its proposed $70.01 million base rate increase and the $1.1 million increase for the proposed Grid Modernization Rider. The Company's position has not changed and it rejects Mr. Kollen's proposal and argument that the Company should forgo the Capacity Charge regardless of the level of base rate increase in this case.

The supplemental payment to the Company being billed through the Capacity Charge was a condition precedent for the Rockport UPA extension through December 7, 2022, and was considered in the total economics of the extension that was approved by the Commission in Case No. 2004-00420:

> Under the terms of the Stipulation, the Rockport purchase power contract will be extended through December 7, 2022. The current wholesale pricing for the power purchase will continue through the extended term of the contract, but there will also be an annual supplemental payment by retail ratepayers to Kentucky Power. This supplemental payment, as set forth in the Stipulation, will be $5.1 million annually in 2005 through 2009, and then increases to $6.2 million annually in 2010 through 2021, and then decreases to $5,792,329 in 2022. Kentucky Power will be entitled to receive these annual supplemental payments in addition to the base retail rates established by the Commission as being fair, just, and reasonable, and the supplemental payments will not be considered in establishing Kentucky Power's base retail rates.[2]

The Company is entitled, as a result of the Commission's order approving the settlement in Case No. 2004-00420, to the capacity charge through December 7, 2022 and that has not changed. Importantly, the AG and KIUC were parties to that settlement and agreed unconditionally to the Company's collection of the Capacity Charge as approved by the Commission.[3]

The Company's conditional proposal in this case to forgo the remaining 2021 and 2022 collections of the capacity charge if its full requested base rate increase is accepted was and continues to be part of a carefully considered balance between customer rate impacts, the Company's financial health, and Kentucky Power having an opportunity to earn its authorized ROE.

[2] Case No. 2004-00420, Order at 2-3 (Dec. 13, 2004).

[3] *Id.*, Order at Appx. A, § III(1)(f) ("This Stipulation and Settlement Agreement is made upon the express agreement by the Parties that the receipt by Kentucky Power of the additional revenues called for by Section . . . III(1)(b) [the annual Capacity Charge tariff amounts at issue here] shall be accorded the ratemaking treatment set out in this Section III. In any proceeding affecting the rates of Kentucky Power during the extension of the UPSA under this Stipulation and Settlement Agreement, the provisions of this Seciton III are an express exception to Section VI(4) of this Stipulation and Settlement Agreement."); *id.* at § VI(4).

Q. WAS THE COMPANY BILLED FOR A 12.16% ROE BY AEGCO THROUGH THE ROCKPORT UPA BILLINGS DURING THE TEST YEAR, AS MR. KOLLEN DESCRIBES AT PAGE 57?

A. No, it was not. The Rockport UPA billings are the result of a FERC-approved formula calculation. The billing formula does include an ROE of 12.16%, but it rarely charges KPCo the full formula ROE due to the operating ratio provision of the billing formula. As discussed in my Direct Testimony, the operating ratio is the percentage of the Rockport capital investment that is in service; it reduces the equity return billed through the UPA to the Company when there is a CWIP balance. Due to the mathematical calculation of the operating ratio, the Company was only effectively billed by AEGCO for an ROE of approximately 6.8% during the test year.

VI. <u>MITCHELL COAL STOCK ADJUSTMENT</u>

Q. MR. KOLLEN CRITICIZES THE REASONABLENESS OF THE COMPANY'S MITCHELL COAL STOCK ADJUSTMENT ON PAGES 38 AND 39 OF HIS TESTIMONY. WHY DOES THE COMPANY FIRST ALLOCATE THE MITCHELL COAL STOCK ADJUSTMENT TO SHORT TERM DEBT AND THEN REDUCE THE REMAINING COMPONENTS OF ITS CAPITALIZATION PROPORTIONALLY?

A. This is done to avoid the totality of the Company's capitalization adjustments, which are almost entirely reductions to capitalization, from resulting in a negative short term debt balance in Section V, Schedule 2, Page 1 as it did in the Company's 2014 base rate case. Company witness Wohnhas explained and addressed this issue in his rebuttal testimony in that proceeding, as other parties raised the negative short-term debt balance as an issue[4]. Setting the short-term debt to zero (rather than allowing it to be negative) and then adjusting the other components of capitalization proportionally was accepted by the Company in rebuttal and ultimately by the Commission in Case No. 2014-00396, and then again in Case No. 2017-00179, to avoid this result..

VII. ADFIT OFFSET PROPOSAL

Q. BASED ON THE RECOMMENDATIONS OF AG/KIUC AND THE COMPANY'S REBUTTAL POSITIONS, HOW WOULD THE PROPOSED ADFIT OFFSET BE IMPLEMENTED?

A. The Company's proposal to offset the proposed base rate increase with remaining excess unprotected ADFIT balances would need to be done as follows:

Implement new base rates that reflect the ordered increase resulting from this case and increase the revenue credit in tariff FTC by the net amount of rate increase taking into account any potential rate credits that could arise from the Company's capacity charge and ES proposals. This would result in a net zero increase in total rates.

[4] *See* Case No. 2014-00396, Wohnhas Rebuttal Testimony at 2-3.-

VIII. PJM LSE OATT EXPENSE LEVEL AND TRACKING

Q. ARE THE COMPANY'S PJM LSE OATT EXPENSES CONTROLLABLE, AS AG/KIUC WITNESS KOLLEN ASSERTS BEGINNING ON PAGE 52 OF HIS TESTIMONY?

A. No, they are not. Kentucky Power has no control over the capital spending of the other AEP operating companies and transmission companies, which makes sense since Kentucky Power is not responsible for providing safe, reliable electric service in those state jurisdictions but does rely upon the AEP Transmission Zone to provide service to its customers. Company Witness Ali addresses this issue in greater detail in his Rebuttal Testimony. Furthermore, the Company's level of PJM LSE OATT expenses is subject to and resultant from PJM's FERC-approved tariff and the FERC approved formula rates of the AEP Companies.

The only small measure of control the Company has over its allocated level of PJM LSE OATT expenses comes from its participation in the AEP Transmission Agreement, which allocates those expenses to Kentucky Power on a 12CP basis rather than 1CP basis. Kentucky Power's participation in the Transmission Agreement has the effect of normalizing annually the level of PJM LSE OATT expense the Company incurs. Company Witness Pearce responds to AG/KIUC's recommendation that the Commission investigate whether the Company should continue to participate in that FERC-approved agreement. It is important to note with regard to the control issue I am addressing, however, that AG/KIUC's recommendation could lead to wild and material swings in the amount of allocated PJM LSE OATT costs to the Company if the charges were incurred on a 1CP basis rather than via the 12CP allocation contained within the AEP Transmission Agreement.

Q. DOES THE COMPANY HAVE AN OPPORTUNITY TO EARN ITS ALLOWED RETURN WITHOUT SOME FORM OF CONTEMPORANEOUS RECOVERY OF PJM LSE OATT EXPENSE?

A. No, it does not. To the extent that the Company incurs costs for PJM LSE OATT expense that are higher than what is embedded in base rates, the Company's earned return will decrease due to non-recovery of FERC approved purchased transmission expense. This expense / recovery imbalance could, and more likely than not would, force the Company into more frequent rate cases.

In addition to allowing the Company an opportunity to earn its authorized rate of return, the Company's proposal to recover incremental PJM LSE OATT expense through Tariff P.P.A. avoids "lumpy" rate increases for customers that result from base rate cases. As Mr. Kollen recognizes in his testimony on page 53, it is my understanding that the Commission is preempted from not reflecting these costs in the Company's retail rates under the filed rate doctrine. As such, a gradual and lower cost way of doing this is a more desirable outcome for the Company and its customers than large step increases resulting from costly and more frequent base rate proceedings.

Q. IF THE COMMISSION ADOPTS THE AG/KIUC RECOMMENDATION TO DISCONTINUE RIDER PPA RECOVERY OF PJM LSE OATT EXPENSE, IS THERE A RESULTANT ADJUSTMENT TO THE ORDERED RATE INCREASE REQUIRED IN THIS PROCEEDING?

A. Yes there is, based upon the filed transmission rates that will be in place on January 1, 2021 before the Company's new base rates take effect. The known and measurable increase that would result from the AG/KIUC recommendation is an additional base rate expense of $14 million, as calculated and shown in Exhibit AEV R1. To be clear, these are the rates that are on file with FERC for the time period that the Company's new rates will be in effect. This increase in FERC-approved costs should either be reflected in the Company's new base rates or recovered incrementally in the Company's next (2021) Tariff PPA update.

IX. RESIDENTIAL BASIC SERVICE CHARGE

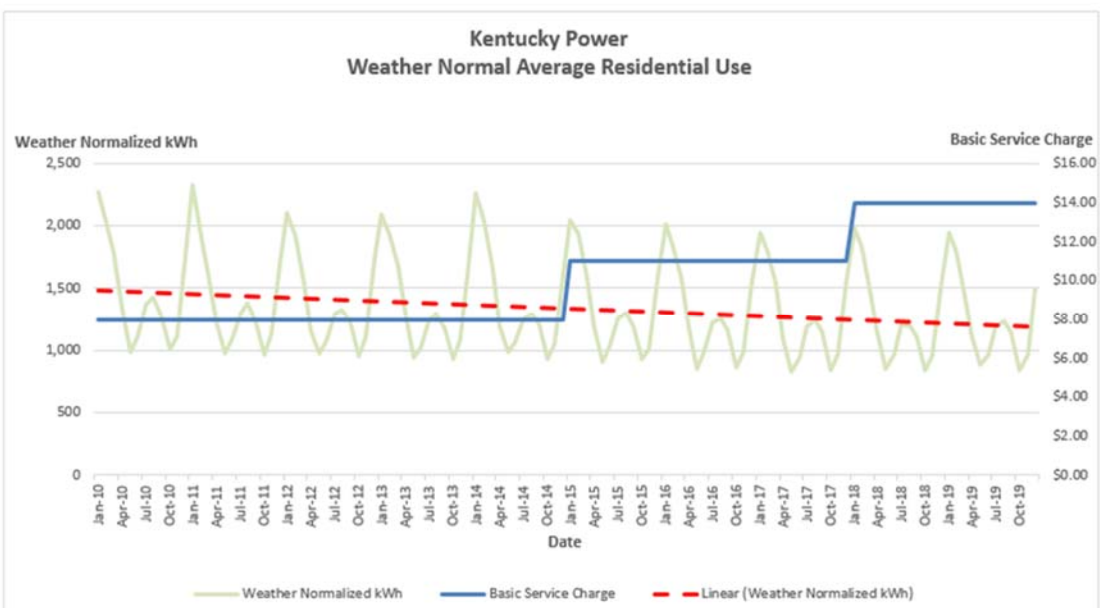
Q. PLEASE ADDRESS JOINT INTERVENORS WITNESS OWEN'S DISCUSSION REGARDING THE RESIDENTIAL BASIC SERVICE CHARGE THAT RESULTS IN HIS RECOMMENDATION ON PAGE 26 OF HIS TESTIMONY.

A. Mr. Owen incorrectly asserts that the Company's proposal will harm low-income customers (page 25); creates a negative feedback loop for energy efficiency investments (page 25); makes irrelevant comparisons between the Company and the other two Kentucky investor-owned utilities ("IOU") (page 26); could harm customers' ability to heat their homes to comfortable temperatures during the winter (page 27); claims that the proposed basic service charge increase will harm customer generators(page 28); and avers that system wide energy usage will increase. These flawed assertions collectively result in his recommendation that the Company's basic service charge should remain at $14 per customer per month. All of these items were addressed in my Direct Testimony, and Mr. Owen does not address the points I made in that document. I will offer further discussion and examples to help illustrate Mr. Owen's misunderstanding on the subject.

Q. WILL THE COMPANY'S BASIC SERVICE CHARGE PROPOSAL INCREASE SYSTEM ENERGY USAGE?

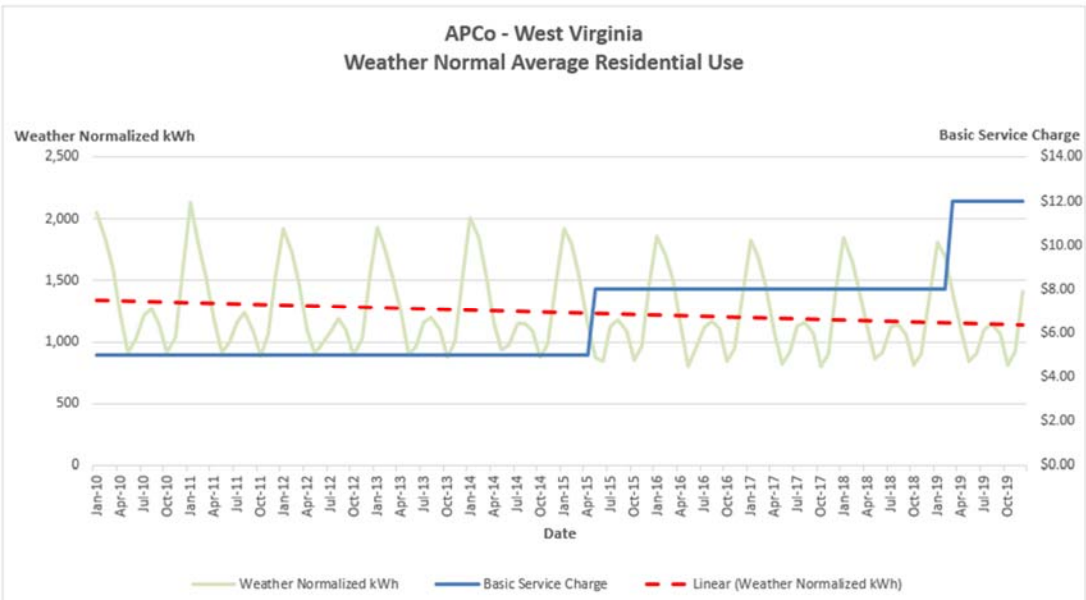
A. No, this assertion is baseless and false. The Company has actually seen a reduction in weather normal usage over the same time period that the residential basic service charges has been appropriately increasing to reduce intra-class subsidies. This is illustrated in Figure AEV-R1:

<u>Figure AEV-R1</u>



The same is true for the Company's affiliate Appalachian Power Company ("APCo") in its West Virginia service territory, which is very similar to the Company's service territory and has also been raising the residential basic service charge over time to reduce its intra-class subsidies as seen in Figure AEV-R2:

<u>Figure AEV-R2</u>



In both cases, neither utility has seen an increase in weather normal usage; rather they have realized *decreases* in weather normal usage over the same period that the basic service charges have been increasing. There are over 480,000 residential customers included in these actual load observations. This proves the fallacy of the Joint Intervenors' generalized claims and assumptions and underscores the importance of evaluating the factual circumstances in a particular utility's jurisdiction rather than relying on editorial "studies" and broad economic theories that do not hold true in the Company's service territory when making rate design recommendations and decisions.

Q. WILL THE COMPANY'S BASIC SERVICE CHARGE PROPOSAL PREVENT ENERGY EFFICIENCY INVESTMENTS?

A. No, it will not prevent energy efficiency ("EE") investments. In fact, those that are considering making an EE investment and actually do the math on what their estimated payback is will see little to no change due to the Company's proposal. For example, a common EE investment such as weatherization (caulking) would still have a payback of less than two years, and the total length of time for the EE investment to pay for itself only increases by 13 days. This small difference in payback days is not enough to influence the binary decision of whether or not to make the investment and as such will not by itself cause a reduction in EE investment. This example calculation is included as Exhibit AEV-R2. Furthermore, this example of reduction in payback days is an "all other things being equal" analysis and does not account for the fact that the Company is also proposing to raise the kWh rate in its proposal, so there may be no actual reduction in payback days of an EE investment.

Q. IS MR. OWEN'S COMPARISON OF THE RECENT DUKE ENERGY KENTUCKY AND LG&E CUSTOMER CHARGE PROPOSALS MEANINGFUL?

A. No it is not. As I discussed in my Direct Testimony on page 18 beginning on line 5:

> Kentucky Power's service territory is primarily mountainous creating challenges for distribution system installation and maintenance that other utilities (referencing IOUs) in the Commonwealth do not experience to the same degree. The combination of lower customer density and challenging topography results in a comparatively higher cost based basic service charge.

Those facts have not changed. As can be seen in the following table[5] the Company's distribution system is much less dense than the other Kentucky IOUs and more closely resembles that of a rural electric cooperative.

Investor Owned Utility	Customers	Distribution Miles	Customers Per Mile
Kentucky Power Company	165,000	10,060	16
Duke Energy Kentucky	142,900	2,933	49
LG&E / KU	948,000	23,157	41

Q. HOW DOES THE COMPANY'S PROPOSED RESIDENTIAL BASIC SERVICE CHARGE COMPARE TO THOSE OF KENTUCKY RURAL ELECTRIC COOPERATIVES?

A. As shown in Exhibit AEV-R3, the Company's proposed basic service charge of $17.50 per customer per month is in line with the Kentucky cooperative average of $18.59, minimum of $9, and maximum of $35.

Q. WHAT WOULD MR. OWEN'S BASIC SERVICE CHARGE PROPOSAL MEAN FOR THE COMPANY'S ELECTRIC HEATING AND LOW INCOME CUSTOMERS?

A. If the Commission were to accept Mr. Owen's proposal that the basic service charge remain at $14, then $5.6 million of revenue would need to be included back in the kWh energy charge. This would be borne disproportionately by electric heating customers since their kWh billing units represent roughly 70% of the residential test year total. Therefore, all other things being equal, the kWh charges for electric heating customers would be $3.9 million higher under Mr. Owen's proposal. We also know that 71% of the Company's low-income assistance customers were also

[5] Source: Company response to KPSC Staff Set 4, Item 71.

electric heating customers, so they would be affected more than the average customer as well.

Q. WILL THE COMPANY'S BASIC SERVICE CHARGE PROPOSAL HARM CUSTOMER GENERATORS?

A. No, it will not. Their bills would be higher by $3.50 per month, but this is in no way a meaningful reduction to the subsidy they are receiving. I quantify and address this later in my rebuttal testimony.

Q. IS THE COMPANY'S PROPOSED RESIDENTIAL BASIC SERVICE CHARGE REASONABLE?

A. Yes. It is reasonable from a cost of service perspective, a policy perspective, and by comparison to the other electric service providers in Kentucky.

X. <u>TARIFF NMS II</u>

Q. PLEASE SUMMARIZE THE POSITIONS OF THE VARIOUS PARTIES TO THE CASE THAT ADDRESS PROPOSED TARIFF NMS II.

A. The various KYSEIA and Joint Intervenors witnesses seem to take issue with every material aspect of proposed tariff NMS II. One goes as far as to seemingly chastise the Company for "wasting the Commission's and intervenors' time and resources[6]" with its proposal. Unsurprisingly, both recommend that NMS II be denied and that Tariff NMS with its 1 to 1 netting compensation remain in effect.

AG/KIUC are supportive of the Company's NMS II proposal and recommend approval in witness Baron's testimony.

[6] KYSEIA witness Barnes Direct Testimony at page 21, line 10.

Q. BEFORE ADDRESSING THE SPECIFICS OF THE VARIOUS PARTIES' GRIEVANCES REGARDING TARIFF NMS II, ARE THERE ANY THRESHOLD MISCONCEPTIONS THAT YOU WOULD LIKE TO DISCUSS?

A. Yes, there are two high level items that must be addressed before getting into the specific issues raised by KYSEIA and the Joint Intervenors:

1. Solar energy, including behind the meter distributed solar energy, is simply and unequivocally energy. That energy, in this case some level of instantaneous kW over a measured period of time, is a commodity. That commodity has a transparent economic value to both the Company and its customers as the Company's hourly energy requirements are settled within the PJM RTO which has transparent and publicly available commodity pricing.
2. The Company, its affiliates, and its parent are not anti-solar. In my capacity at AEPSC I am currently involved in the development of over 200 MW of solar generation projects in various stages of development. The Company also supports customers' ability to produce their own on-site power when the correct tariffs are in place to isolate the economic impacts of that decision to the customer in question. Compensation from other customers beyond what they would have otherwise paid for electricity should not be involved in the economic decision made by prospective customer generators.

Q. KYSEIA AND THE JOINT INTERVENORS BOTH MAKE CLAIMS REGARDING WHAT IS REQUIRED BY THE NET METERING ACT AND HOW IT SHOULD BE IMPLEMENTED; DO YOU AGREE WITH THOSE CLAIMS?

A. No, I do not. The recommendations of Mr. Barnes and Mr. Owen that Tariff NMS remain in place so customers can receive 1 to 1 netting of billable kWhs from any generation produced by their eligible generators simply does not fit the statutory definition of net metering. KRS 278.465(4) states:

> "Net metering" means the difference between the:
>
> *(a) Dollar value of all* electricity generated by an eligible customer-generator that is fed back to the electric grid over a billing period *and priced as prescribed in Section 2 of this Act: and*
>
> *(b) Dollar value of all electricity consumed by the eligible customer-generator over the same billing period and priced using the applicable tariff of the retail electric supplier.*

The clear and unambiguous language of KRS 278.465 on this matter is that net metering in the Commonwealth is financial in nature, not volumetric as KYSEIA and the Joint Intervenors recommend. The structure of proposed Tariff NMS II is based upon and would implement the prescribed financial netting of the dollar values of energy consumed and energy generated, which are not equal in price. Except for those current customers that are grandfathered under Tariff NMS pursuant to KRS 278.466(6), that tariff no longer meets the statutory definition of net metering service and should not remain as an option for new customers.

Q. DOES THE NET METERING ACT REQUIRE THAT NET METERING TARIFF DESIGNS AND STRUCTURES BE CONSISTENT ACROSS ALL UTILITIES IN THE COMMONWEALTH, AS MR. BARNES SUGGESTS AT PAGE 7?

A. No it does not, and to additionally require this makes little sense, as the various electric suppliers in the Commonwealth are all situated differently in regards to how they provide service and what their actual avoided costs may be. For instance, the Company, EKPC and Duke are all members of the PJM RTO while LG&/KU are not members of an RTO and some Cooperatives are TVA distributors. Moreover, the Net Metering Act explicitly provides that net metering ratemaking processes consider utility-specific costs, as the Commission recognized last year.[7] There is no reason that whatever is decided for the first supplier before the Commission on this matter, in this case the Company, should have to apply to all other suppliers. Furthermore, the statute does not require that a stakeholder forum is required for any or all of the suppliers to be able to implement a new net metering tariff that comports with the law, nor would such a forum make practical sense for the reasons above.

Q. DOES THE NET METERING ACT REQUIRE THAT A LARGE SUBSIDY EXIST[8] FOR A SUPPLIER TO PETITION FOR A NEW NET METERING TARIFF THAT ELIMINATES 1 TO 1 NETTING OF ALL KWH?

A. No it does not. In fact, the only statutory requirement for initiating a proceeding for a new compensation structure for net metering customers is that it be "initiated

[7] Case No. 2019-00256, Order at 32 (Dec. 18, 2019); KRS 278.466(5).
[8] Barnes at 20 and Owen at 38.

by a retail electric supplier or generation and transmission cooperative on behalf of one or more retail electric suppliers.[9]" No "material subsidy" criteria exists in the law, nor should the Commission impose one. In addition to being contrary to the Net Metering Act, it is bad policy and rate design to wait while a subsidy builds to a material size to then address it. Providing fair compensation to net metering customers from the outset is a more desirable and fair outcome for all of the Company's customers than to wait until a large subsidy exists and then try to address the issue once its inertia is much greater. There is simply no reason to require non-participating customers to bear an increasing proportion of costs caused by net metering customers before implementing the plain requirements of the statute, which became effective January 1, 2020. This is an easy lesson learned from the heated and politically charged rate cases attempting to do just this in some western state utilities, it is best to address the inequity before it becomes large.

Q. KYSEIA AND THE JOINT INTERVENORS BOTH CLAIM THAT THERE IS NO EVIDENCE A SUBSIDY EXISTS UNDER TARIFF NMS. IS THIS TRUE?

A. No, it is not. A subsidy absolutely exists. Customer generators are being compensated at over 10 cents per kWh for excess generation (the full retail rate), the Company's actual avoided costs of electric service for that excess generation are less than 4 cents per kWh. Customer generators are being paid by the Company and other customers roughly three times what their generation is worth. Non-

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[9] KRS 278.466 (3).

participating customers paying more for NMS customers' excess generation than they would have otherwise for the same electric service is a subsidy.

Q. WHAT WAS THE MARKET VALUE OF SOLAR ENERGY DURING THE TEST YEAR FOR A DISTRIBUTED GENERATION SYSTEM?

A. As I describe earlier, solar energy is a commodity. That commodity consists of energy, capacity, and renewable attributes. I will discuss the renewable attributes later in my testimony. The energy and capacity value of the Company's test year average residential distributed generation ("DG") solar system is $515. The average system is 8.84 kW AC, produces roughly 13,374 kWh energy, and represents about 3.36 kW of market capacity. The energy is valued at the hourly PJM LMP for the Kentucky Power residual load aggregate and the equivalent amount of unforced capacity is valued at the prevailing PJM RPM base residual auction clearing price. This is shown in the following table:

Typical Test Year Residential System		
System Nameplate Capacity kW (AC)		8.84
System PJM Capacity kW (AC)		3.36
System kWh Output		13,374
19/20 BRA Price $/MW-day	$	100.00
Average Hourly LMP $/MWh	$	29.36
System Energy Value	$	393
System Capacity Value	$	123
Total	$	515
Unitized Market Compensation $/kWh	**$**	**0.0385**
NMS Compensation Rate $/kWh	**$**	**0.1033**

This analysis looks at the commodity value during the test year as if the eligible customer generator were an independent power producer (which they are not because of retail ratemaking constructs such as net metering tariffs), but it is still informative as a data point to illustrate what the actual fungible commodity being produced is worth in dollar terms. As can be seen, the test year energy and capacity value using this independent power producer view would be $38.5/MWh, which is considerably less than the $103.3/MWh NMS customers are receiving for their non-instantaneously netted generation. The calculations are included in Exhibit AEV-R4.

Q. HAS THE COMMISSION RECENTLY ADDRESSED WHAT A CUSTOMER SHOULD BE COMPENSATED FOR IN TERMS OF AVOIDED COSTS RELATED TO SOLAR ENERGY?

A. Yes. In Case No. 2020-00016, LG&E/KU proposed a 100 MW solar power purchase agreement ("PPA") and two renewable power agreements ("RPA") for two industrial customers in the companies' service territory to buy the majority of the 100 MW PPA, pursuant to LG&E/KU's existing Green Tariff Option. LG&E proposed under the RPAs to compensate the two industrial customers for the solar output they were purchasing in addition to their standard tariff billings at the avoided cost of energy charges and peak and intermediate generation demand charges. Under the proposed structure, the customer off-takers would continue to pay full base demand charges, as those costs are designed to recover costs associated with the transmission and distribution systems. Any excess energy from the PPAs above the customer off-takers' 15-minute interval load would be purchased back by LG&E at its avoided cost pricing under its Cogen/SPP tariff.

Q. WHAT DID THE COMMISSION DECIDE IN REGARDS TO THE PROPOSED RPA COMPENSATION STRUCTURE IN THE LG&E/KU CASE?

A. The Commission agreed with the provision of the RPAs not to reduce base demand charges because the RPA customers continue to utilize distribution and transmission systems that are associated with and recovered through the base demand charge. However, the Commission disagreed with the provision that intermediate and peak demand charges should be reduced by coincident solar energy production <u>because intermediate and peak demand costs should not be reallocated to other customers in a future rate proceeding</u>.[10]

The effect of this is that the Commission is only allowing actual avoided costs of energy, and not generation capacity, to be credited to the customer off-takers under the LG&E/KU RPAs. The Commission approved compensation is significantly less than what KYSEIA and the Joint Intervenors seek in this case, when they both adamantly seek to maintain customer compensation for DG solar under existing tariff NMS that credits customers at the full retail rate (including generation, transmission and distribution system costs which they use every day), which effectively pretends that NMS customers' bills act as a battery.

[10] Case No. 2020-00016 Order at 21.

Q. DO THE COMPANY'S PROPOSED AVOIDED COST RATES UNDER NMS II PROVIDE A "FULL ACCOUNTING OF THE COSTS AND BENEFITS" OF ELIGIBLE CUSTOMER GENERATORS'[11] DISTRIBUTED GENERATION SYSTEMS?

A. Yes, they do. I will now address each of the solar "value" items raised by Mr. Owen on page 37 of his testimony:

1. Reduced transmission and distribution losses – Both the value of avoided transmission and distribution losses are included in the avoided cost of energy rate of proposed tariff NMS II. The value of locational transmission loses are included in the PJM LMPs used as the basis for the avoided cost of energy, the energy value is then grossed up for avoided primary distribution level losses.
2. Reduced distribution level congestion – The Company's highest distribution loading (peak loads) events happen early on cold winter mornings when it is dark. Net metering customers' solar generating systems either have no impact on these peak loadings, or a very small effect as the sun has just starting coming up. Regardless of that fact, the Company designs its distribution system to serve the highest peak load. Net metering customers' solar systems could reduce the loading on a circuit but to do so in an amount that would be enough to defer a traditional solution; the generation amount would need to be significant and concentrated on the circuit where needed and at the time high loading exists. This is not the

[11] Owen at 37.

case in the Company's service territory and as such there is no monetary value included in the NMS II avoided cost rate for this item. Furthermore, I have been advised by Company witness Phillips that the Company routinely conducts load flow analysis of its distribution system to ensure there are no load flow/loading (congestion) issues.

3. Peak load reduction or shifts – The financial impact of peak load reductions is included in the NMS II avoided cost pricing in the generation capacity avoided cost and the transmission fixed cost price components. The value of peak load reductions are also included in the avoided cost of energy because the price is weighted to on-peak periods based on expected solar production.

4. Reduced costs along the fuel supply line – There are no reduced costs along the fuel supply line for the Company resulting from net metering customers. The Company purchases the entirety of its load obligation from the PJM energy market and its generation resources dispatch based upon PJM's LMPs, the net effect of which is what customers pay for power supply through the Company's rates. PJM LMPs are based upon the marginal cost of energy supply in that hour, the energy supply benefits that could be reasonably associated with net metering customers of the Company is included in the avoided cost of energy in NMS II.

5. Reduced environmental liabilities and/or environmental compliance costs – The Company's environmental compliance costs and or liabilities (such as AROs for example) are not based on load levels and are not reduced or

offset by net metering customers' investments in solar generation on their premise. Those costs and obligations are based upon the continued operation or post retirement obligations of Commission approved assets that serve the capacity requirements of all customers. Some, like scrubber chemicals and allowance costs, are based on the variable operations of the Company's generation resources. As discussed earlier, those assets dispatch based on price signals from PJM, not based upon the Company's hourly load. If the Company did incur some sort of load based environmental compliance cost, I would agree that it should be included in the avoided cost pricing of NMS II for the amount of actual load reduced by the customer generators.

6. Avoided generation capacity investments – The value of this is explicitly included in the Generation capacity pricing component of NMS II. Furthermore, the Company is capacity sufficient, so it is not avoiding any capacity purchased through peak load reductions by net metering customers, rather it is in theory making an additional sale of length in to the PJM RPM market when its generation capacity 5 CPs are reduced.
7. Reduced grid support services – Mr. Owen does bring up a good point regarding ancillary grid services. I did fail to include this in my originally filed avoided cost rates for NMS II. When a net metering customer's system generates and the Company's load is lowered, the Company does avoid paying load based PJM ancillary service charges. The following table is a

summary of these avoided costs based upon a recent 12 months actual cost for these items.

Load Based PJM Ancillary Services $/MWh		
Sched 1-A: Sched, System Control, & Dispatch	$	0.06
Sched 2: Reactive Supply & Voltage Control	$	0.40
Sched 3: Regulation & Frequency Response	$	0.11
Sched 5: Synchronized Reserve	$	0.02
Sched 6: DA Operating Reserves	$	0.03
DA Scheduling Reserve	$	0.01
Total Avoided Cost for NMS II	$	0.63

I have updated the proposed NMS II avoided cost pricing to include this amount as I discuss later in my rebuttal testimony.

8. Improve grid resiliency – I have been advised by Company Witness Phillips that DG solar installations can actually slow down restoration efforts as crews working on a circuit with DG need to make sure that the DG is isolated from the Company's system before restoration work begins to avoid crews contacting lines being backfed by a DG system. There is no evidence of any monetary avoided cost value from net metering customers' systems in the Company's service territory related to this item and as such no value is included in the NMS II avoided cost rate.

Q. ARE THERE ADDITIONAL ITEMS TO BE ADDRESSED IN THIS AREA OF AVOIDED COSTS?

A. Yes. The cost of carbon is not included in the Company's proposed avoided cost rates because there is no actual financial avoided cost of carbon as of yet for the Company to include. Said another way, the Company currently incurs no incremental cost, nor does it have an existing cost in its rates, for carbon emissions in any form. If/when a carbon tax, or a carbon adder is included in the market price

(PJM LMP) of energy, then naturally that pricing would be reflected in the Company's NMS II avoided cost rates. The Company does not oppose the inclusion of actual avoided carbon costs but maintains that it would be inappropriate to impute some form of unquantified societal carbon costs in the Company's rates for NMS II.

Furthermore, as I discussed in my Direct Testimony at page 28, net metering customers' generators produce RECs, which are the legal entitlement to 1 (one) MWh of renewable generation and *all associated environmental attributes.* The Company does not receive the RECs from net metering customers' systems, nor does it need to, and as such, net metering customers should not be compensated from the Company and its other customers for any additional environmental attributes associated with those systems. For instance, net metering customers are free to register and sell their RECs into state compliance markets, to other customers seeking to purchase renewable offsets for a sustainability goal, or even back to the developer/installer of their system to help buy-down solar system costs. If the Company were ever subject to a renewable portfolio standard in the Commonwealth or nationally, it would be appropriate to include an option in NMS II for customers to sell any qualifying RECs produced by their systems back to the Company as a means of compliance.

Q. IS A "VALUE OF SOLAR STUDY" REQUIRED TO FULLY ACCOUNT FOR THE BENEFITS AND COSTS OF SOLAR NET METERING FOR THE PURPOSE OF APPROVING NMS II, AS SUGGESTED BY KYSEIA AND THE JOINT INTERVENORS?

A. No, a value of solar study is not required or necessary. As I just demonstrated, and with the refinements to NMS II proposed in my rebuttal testimony, a full accounting of the costs and benefits of net metering customers' service has already been performed based on the Company's actual costs and those it can avoid.

Q. HAVE YOU MADE UPDATES TO THE PROPOSED NMS II AVOIDED COST RATE BASED ON ISSUES RAISED IN DISCOVERY AND INTERVENOR TESTIMONY?

A. Yes, I have made four refinements to the proposed avoided cost pricing of NMS II based on discovery and testimony received thus far in this proceeding.

1. In response to Mr. Barnes' point raised on page 16 of his testimony, I have separated the residential and commercial systems to produce updated residential and new commercial avoided cost rates under proposed Tariff NMS II. The class load shapes of residential and the Company's commercial customers are quite different. This does influence the proposed avoided cost rates for each, therefore I have refined the proposed avoided cost pricing for NMS II to include this change.

2. Based on the Company's response to Staff data request 4-81, and the refinement discussed in item 1 above, the test year-end average residential

customer system was 8.84 kW AC and the average commercial customer system was 26.1 kW AC, this is included in the refined avoided cost rates.

3. In response to Mr. Barnes' discussion of local systems versus the Company's utility scale profile on page 17 of his testimony, I updated the solar profile and estimated output based on the above solar systems modeled using the National Renewable Energy Laboratory publicly available PV Watts calculator and resulting hourly solar system generation information for locations within the Company's service territory. The shape of the output is almost identical to the utility scale profile used by the Company, but the expected capacity factor of rooftop systems were about 3% less than the 20% used by the Company in its originally filed NMS II avoided cost pricing. This change has also been incorporated into my updated NMS II pricing.

4. Based on Mr. Owen's testimony I have added the avoided cost of load based ancillary services as discussed above to the proposed NMS II pricing.

Q. WHAT IS THE EFFECT OF THESE REFINEMENTS TO THE PROPOSED NMS II AVOIDED COST PRICING?

A. The avoided cost rate for residential customers went down slightly to \$0.03553/kWh from the originally filed \$0.03659/kWh; and the rate applicable to commercial systems went up slightly to \$0.03778/kWh. The calculations associated with these refinements are included in Exhibits AEV-R5 and AEV R6.

Q. REGARDING MR. BARNES' STATEMENTS ON PAGE 20 OF HIS TESTIMONY CONCERNING CLASS ALLOCATION CONSIDERATIONS, ARE THESE COSTS AVOIDED OR SHIFTED?

A. The cost allocations within the class cost of service are not avoided when the class allocators change, they are simply shifted from one class to another class of customers, this is what we generally refer to as an inter-class cost shift. To be clear, besides the avoided costs I have already discussed at length in my direct and rebuttal testimonies, these costs are not eliminated from the total cost of service; they are just shifted to and paid for by other customers. This is exactly the type of reallocation the Commission was critical of regarding LG&E and KU's proposed RPAs in Case No. 2020-00016. Interestingly enough, since the Company is seeing NMS installations in its residential, general service, and large general service (I will refer to general service and large general service collectively as "commercial") classes, most distribution level costs that would be shifted from reduced class allocation peaks resulting from net metering would just be shifted back and forth between these classes since they represent almost all distribution level service.

Q. DID YOU ANALYZE WHAT THE NET AFFECT OF CLASS COST OF SERVICE COST SHIFTING WOULD BE ON THE RESIDENTIAL AND COMMERCIAL CLASSES?

A. Yes. I compared the residential and commercial typical test year systems to the 12CPs used in the class cost of service study and determined what the estimated allocator reduction would be. I then extrapolated that effect across the entire class and assumed that those costs were in fact shifted away and avoided. This is an important assumption because it is not factually accurate, but for the benefit of debunking this line of thinking proposed by the participants in this case I will assume it to be true for purposes of this analysis. The class cost allocation reductions were then applied to the class functional revenue requirements that are the basis for the Company's rate design. The next part of the analysis is the important part that is overlooked by KYSEIA, one also has to adjust the billing units used to collect that new level of costs as net metering customer do not produce the same amount of billing units as an average customer due to their behind the meter generation. The net effect of the hypothetical reduction in avoided class costs and the reduction in billing units is that class averages rates actually go up. The following table shows a summary of this:

Base Rate Revenue Targets	**Residential**	**Total Commercial**	
Demand	$ 115,987,406	$ 69,116,860	**a1**
Energy	$ 64,765,247	$ 36,705,780	**a2**
Dist Primary	$ 42,886,747	$ 26,667,375	**a3**
Dist Secondary	$ 20,643,519	$ 10,176,646	**a4**
Customer	$ 13,525,407	$ 5,334,606	**a5**
	$ 257,808,327	$ 148,001,267	**a=sum(a1-a5)**
Test Year Billable Sales kWh	1,992,407,328	1,143,106,490	**b**
Test Year Class Avg Realization $/kWh	***$ 0.1294***	***$ 0.1295***	**c=a/b**
NMS Net Profile Allocation			
Non-Fuel G&T Demand	66.3%	55.8%	**d**
Energy	52.3%	47.3%	**e**
Distribution	48.6%	34.5%	**f**
Revenue Targets Reduced for NMS Profile	**Residential**	**Total Commercial**	
Demand	$ 76,899,650	$ 38,567,208	**g1=a1*d**
Energy	$ 33,872,224	$ 17,350,822	**g2=a2*e**
Dist Primary	$ 20,842,959	$ 9,200,244	**g3=a3*f**
Dist Secondary	$ 10,032,750	$ 3,510,943	**g4=a4*f**
Customer	$ 13,525,407	$ 5,334,606	**g5=a5**
	$ 155,172,991	$ 73,963,823	**g=sum(g1-g5)**
Billable Sales Reduced for Netting	1,042,029,033	540,346,438	**h=b*e**
NMS Class Avg Realization $/kWh	***$ 0.1489***	***$ 0.1369***	**j=g/h**
Increase in Avg Realization (Rates)	15%	6%	**j > c**

I again want to emphasize that the actual class revenue targets would not be reduced by what was assumed in this analysis because some of the costs shifted away in one class would be shifted back by net metering in another class. Even given the unreasonable assumption that the shifted costs simply disappear for a class, the net increase in rates that would result shows that the reduction in billing units is greater than the inter-class cost shift, resulting in higher rates for all customers within that class.

This analysis and the associated calculations are included in Exhibit AEV-R7.

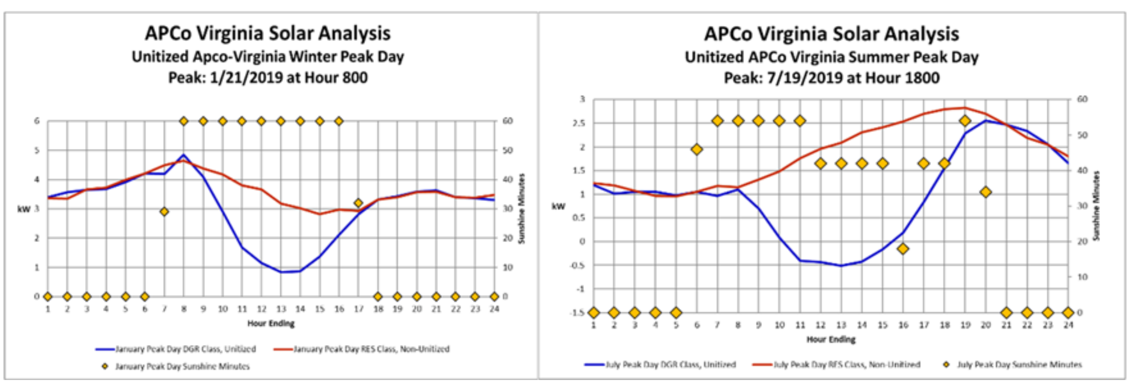
Q. DO THE NET METERING ACT OR GENERALLY ACCEPTED RATE MAKING PRINCIPLES REQUIRE A SEPARATE CLASS COST OF SERVICE FOR NMS CUSTOMERS?

A. No, they do not. This recommendation by KYSEIA and the Joint Intervenors highlights their inexperience in this area. A separate class cost of service or load profile are not necessary to produce just and reasonable rates for retail electric service. The results of the class cost of service study are informative and used as the high-level basis for rate design (allocating revenue targets) but are not an exact science for every customer or sub group of customers within a major class. Rates for electric service are averages, it was never intended nor is it practical to make rates for every specific customer or grouping of customers within a major class. There are many Commission-approved rates within customer classes that do not have a separate class cost of service study as the basis for determining those just and reasonable rates. For instance, the GS Recreational Lighting, GS LMTOD, GS

Unmetered, SGS TOD and MGS TOD rates and associated customers are all included in the GS secondary class. The resulting rates and expected revenue from each Commission-approved tariff rate within that grouping is then divided out in the rate design process. No separate class cost of service study is needed.

Q. ARE THE UNDERLYING LOADS OF NET METERING CUSTOMERS ANY DIFFERENT ON AVERAGE FROM THE REST OF THEIR CUSTOMER CLASS?

A. No. Net metering customers' underlying loads are no different than the other customers in their standard tariff class, they have simply chosen to add behind the meter generation to their load. This changes their net load shape and produces exports of excess energy to the Company's grid. They still contribute to the Company's peaks as I mentioned earlier. The Company's affiliate across the state line in southwest Virginia, APCo, was ordered in a 2014 rate case to install interval metering on its solar net metering customers for the purpose of evaluating these customers' net load shapes in comparison to non-net metering customers' load shapes. The result is exactly what you would think it would be: they are the same except when solar generation is reducing the load shape, and they still contribute to the utility's cost causing peaks as can be seen in the summary graphs below.



This is a very telling analysis as APCo's Virginia territory is very similar to the Company's in its level of electric heating, geography, and density. It being directly adjacent to the Company's service territory also means that there would be no material difference in the average solar generation shape. As I have discussed already, there are avoided costs related to these peak reductions and excess sales of net energy back to the Company's grid. However the actual value of those avoided costs is roughly 1/3rd of the amount NMS customers receive when they are compensated at the full retail rate. The Company and its other customers are paying a greater amount for the peak reduction than it is worth. This, again, is considered a subsidy.

Q. IS OKLAHOMA GAS AND ELECTRIC ("OG&E") AN AFFILIATE OF THE COMPANY AS DISCUSSED BY KYSEIA?[12]

A. No. KYSEIA references an OG&E case regarding net metering and falsely state that it is from an affiliate of the Company. The Company's affiliate in Oklahoma is Public Service Company of Oklahoma, commonly referred to as "PSO". If it were relevant to the Company's application for new net metering rates under NMS II in the Commonwealth of Kentucky with its own unique laws and circumstances, I would point out that PSO pays SPP LMP (avoided cost of energy) for excess customer generation under its net metering tariff.

[12] Barnes at 12 and Van Nostrand at 10.

Q. DOES NMS II INCENT CUSTOMERS TO SHIFT THEIR USAGE TO ON-PEAK PERIODS?

A. No. Mr. Barnes alleges at page 23 of his testimony that the Company's proposed rate structure and netting periods would incent customers to shift their load to on-peak periods. This is not true, there is no incentive for customers to use any additional on-peak power besides what is produced by their behind the meter generation. Any aligning of customer load and behind the meter generation would not lead to increased on-peak load costs for the Company as that load is netted at the customer's meter. There is no price signal to increase on-peak usage beyond what their generation systems produce as the applicable rate is the standard residential rate. What the NMS II construct may incent is an investment in storage by customers to more closely align their behind the meter generation and their load requirements after their solar generation reduces each evening. There are no cost-causation issues here, the allegations of causing increased system costs are a red herring at best.

Q. PLEASE ADDRESS MR. OWEN'S ISSUES WITH THE REVISED APPLICATION FEE LANGUAGE AND CHARGES IN NMS II.

A. Again, to reduce subsidization of net metering customers by non-participating customers, customers should pay an application fee more closely aligned with the actual cost of processing applications. They should fully pay for any required engineering studies needed to integrate their systems with the Company's distribution system; otherwise non-participating customers pay those costs in their rates. This is the reason for the application fee changes and the removal of the fee cap in NMS II.

Q. WHAT WOULD THE TYPICAL MONTHLY BILL BE FOR AN NMS II CUSTOMER?

A. The following tables show a typical customer bill with a typical test year solar installation billed on NMS, NMS II and standard tariff rates for comparison's sake.

Typical Residential Customer and System Example

	NMS Bill		NMS II Bill		Standard Tariff	
Rate Billing	$	35	$	100	$	166
Excess Energy Credit			$	(19)		
Total Net Bill	**$**	**35**	**$**	**81**	**$**	**166**

Typical Commercial Customer and System Example

	NMS Bill		NMS II Bill		Standard Tariff	
Rate Billing	$	34	$	195	$	386
Excess Energy Credit			$	(67)		
Total Net Bill	$	34	$	128	$	386

Q. IN YOUR OPINION, WHAT WEIGHT SHOULD BE GIVEN TO THE TESTIMONY RECOMMENDATIONS OF KYSEIA AND THE JOINT INTERVENORS REGARDING NMS II RATE DESIGN AND THE CALCULATION OF ACTUAL AVOIDED COSTS?

A. Little if any weight should be given to their recommendations from a technical cost of service and rate design perspective. KYSEIA and the Joint Intervenors admit in discovery that their witnesses have never themselves produced an electric utility cost of service study: "James N. Van Nostrand has no such studies or calculations."[13] "Justin R. Barnes has not performed electric utility cost of service

[13] KYSEIA response to KPC 1-1.

studies or electric utility customer load research studies."[14] The only actual experience they can claim in this area besides advocacy for their cause is editorial commentary and proposed changes on rate design studies and calculations produced by others. This is an important distinction to raise when deciding technical matters such as avoided costs in the cost of service, class study allocations and effects, and rate design. The only other witness in this proceeding that opines on proposed tariff NMS II that has produced electric utility cost of service and rate design studies is AG/KIUC witness Baron, and he agrees at page 24 of his testimony that the Company's excess energy payment rate is reasonable.

Q. ARE THERE ANY ADDITIONAL CHANGES THAT SHOULD BE MADE TO PROPOSED TARIFF NMS II?

A. Yes, in the availability of service section the following sentence:

"If the cumulative generating capacity of net metering systems reaches 1% of the Company's single hour peak load during the previous year, upon Commission approval, the Company's obligation to offer net metering to a new customer-generator may be limited." Should be changed to read as follows:

"If the cumulative generating capacity of net metering systems reaches 1% of the Company's single hour peak load during a calendar year, the Company shall have no further obligation to offer net metering to any new customer-generator." This change updates proposed tariff NMS II to match KRS 278.466(1).

[14] Join Intervenors responses to KPC 1-8 and 1-16.

Q. IN SUMMARY, HAS THE COMPANY MET ITS BURDEN OF PROOF?

A. The Company in its direct case, through discovery, and in rebuttal has produced a substantial amount of evidence in favor of the avoided cost pricing under NMS II that comports with the applicable KRS statutes. The Company has met its burden of proof with actual calculations and cost of service analysis specific to the Company and its customers rather than editorial comments and advocacy papers from other states. Proposed tariff NMS II is just and reasonable and should be approved.

XI. PURPA & COGEN/SPP TARIFFS

Q. BEFORE ADDRESSING KYSEIA'S CONCERNS REGARDING TARIFF COGEN/SPP, HAVE THERE BEEN DEVELOPMENTS AT FERC REGARDING THE PUBLIC UTILITY REGULATORY POLICIES ACT ("PURPA") SINCE THE COMPANY FILED THIS CASE?

A. Yes, there have been. Most notable for the Company's COGEN/SPP tariffs is that under FERC Order 872, the Company no longer has a purchase obligation on PURPA qualifying facilities ("QFs") up to 20 MW. The new QF project purchase obligation for the Company is 5 MW and less because it is a member of an RTO. The Company's COGEN/SPP tariffs should be updated to reflect this.

Q. DO YOU AGREE WITH MR. BARNES' CRITICISMS OF THE COGEN/SPP PRICING?

A. No. First, retail commissions have a great amount of latitude in how they implement PURPA. How this is accomplished is different from jurisdiction to jurisdiction and nothing has changed in that regard. Mr. Barnes' recommendation that QFs are entitled to a locked-in rate for a duration of time is not consistent with FERC Order 872 or the Commonwealth's regulations on PURPA implementation. Nothing in either requires that the energy portion of contractual payments must be fixed for any duration of time. They can be completely fixed in nature or change hourly based on actually avoided energy costs (PJM LMP for the Company).

Additionally, Mr. Barnes' criticism of the 40 year life for the hypothetical combustion turbine ("CT") used in the COGEN/SPP capacity rate is unfounded. All of the Company's affiliates' CTs use at least a 40 year depreciable life.

Q. HOW SHOULD THE AVOIDED CAPACITY RATE BE CALCULATED FOR TARIFF COGEN/SPP?

A. It should be done in a consistent manner whatever method the Commission determines is prudent. By that I mean that cherry picked values from various different calculations should not be considered. The calculations should be consistent with whatever method of valuing the avoided capacity component the Commission finds to be reasonable. Those methods could be the hypothetical CT calculation currently utilized in Cogen/SPP, using PJM's net cost of new entry ("CONE"), or even using PJM's RPM base residual auction clearing price, or even zero, as the Company currently is capacity sufficient so any additional capacity length from a QF project would just make the Company longer in its FRR plan and potentially lead to an incremental sale of length in to RPM. The following table illustrates the various capacity credits that would result from these methods.

Method	$/Mwday	$/kW Month
Hypothetical CT	$ 246	$ 7.49
Net Cone	$ 288	$ 8.75
PJM RPM BRA	$ 100	$ 3.04

The Company continues to believe that its simplified hypothetical CT calculation is reasonable, but Tariff Cogen/SPP should be updated for however the Commission decides this matter in this case and for the changes I discussed earlier.

XII. CONCLUSION

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes.

Exhibit AEV R1

Kentucky Power Company

Adjustment to Increase PJM LSE OATT expense to reflect October 2020 filed rates

Test Year Twelve Months Ended 3/31/2020

LINE NO.	DESCRIPTION	KPCO TOTAL COMPANY ADJUSTMENT	ALLOCATION METHOD	ALLOCATION FACTOR	KENTUCKY PSC RETAIL JURISDICTION ADJUSTMENT	
	LSE OATT CHARGE ACCOUNTS					
1	4561005 Firm and Non-Firm Pt 2 Pt Transmision Revenues	$ -	Specific	1.00	$ -	**Increase Other Operating Revenues**
2	4561002 RTO Formation Costs	$ -	Specific	1.00	$ -	**Reduce Other Operating Revenues**
3	4561035 PJM Affiliated Trans NITS Cost	$ (8,623,976)	Specific	1.00	$ (8,623,976)	**Reduce Other Operating Revenues**
4	4561036 PJM Affiliated Trans TO Cost	$ (36,257)	Specific	1.00	$ (36,257)	**Reduce Other Operating Revenues**
5	4561060 Affil PJM Trans Enhancmnt Cost	$ (209,714)	Specific	1.00	$ (209,714)	**Reduce Other Operating Revenues**
6	5650012 PJM Trans Enhancement Charge	$ 10,012,118	Specific	1.00	$ 10,012,118	**Increase Transmission Expense**
7	5650016 PJM NITS Expense - Affiliated	$ 8,176,054	Specific	1.00	$ 8,176,054	**Increase Transmission Expense**
8	5650019 Affil PJM Trans Enhncement Exp	$ 1,207,456	Specific	1.00	$ 1,207,456	**Increase Transmission Expense**
9	5650021 PJM NITS Expense - Non-Affiliated	$ 62,627	Specific	1.00	$ 62,627	**Increase Transmission Expense**
10	5650015 PJM TO Serv Expense - Affiliated	$ 42,572	Specific	1.00	$ 42,572	**Increase Transmission Expense**
					$ 28,370,773	Net Increase in LSE OATT Expense
					$ -	
					$ 14,299,049	Originally Filed Amount of W23
					$ 14,071,724	Increase Based on Filed Rates

Exhibit AEV R1

		Test Year
		A
4561005 Firm and Non-Firm Point to Point Transmision Revenues	$	766,100
4561002 RTO Formation Costs	$	(135,212)
4561035 PJM Affiliated Trans NITS Cost	$	(39,632,057)
4561036 PJM Affiliated Trans TO Cost	$	(166,623)
4561060 Affil PJM Trans Enhancmnt Cost	$	(963,755)
subtotal 456	$	(40,131,547)
5650012 PJM Trans Enhancement Charge	$	(1,140,098)
5650016 PJM NITS Expense - Affiliated	$	37,573,604
5650019 Affil PJM Trans Enhncement Exp	$	5,548,943
5650021 PJM NITS Expense - Non-Affiliated	$	287,808
5650015 PJM TO Serv Expense - Affiliated	$	195,641
sub total 565	$	42,465,899
Total LSE OATT Expense Retail Demand	$	82,235,181
Total LSE OATT Expense Retail Energy	$	362,264
Total LSE OATT Expense	**$**	**82,597,446**

Filed 2021 Rates	Adjustment
B	=B-A
$ 766,100	$ -
$ (135,212)	$ -
$ (48,256,033)	$ (8,623,976)
$ (202,880)	$ (36,257)
$ (1,173,469)	$ (209,714)
$ (49,001,494)	$ (8,869,947)
$ 8,872,020	$ 10,012,118
$ 45,749,659	$ 8,176,054
$ 6,756,399	$ 1,207,456
$ 350,435	$ 62,627
$ 238,213	$ 42,572
$ 61,966,725	$ 19,500,826
$ 110,527,126	$ 28,291,944
$ 441,093	$ 78,829
$ 110,968,219	**$ 28,370,773**

AEP Zone - PJM LSE OATT Expense Allocation Calculation
Exhibit AEV R1

	AEP Zone Allocation			NITS Expense			
NSPL	MW	%		OpCo ATRR	$ 964,119,420	Jan 1 2021 PTRR - Less True Up	
AEP (Including CRES)	19,101	84.90%		Transco ATRR	$ 1,132,242,117	Jan 1 2021 PTRR - Less True Up	
Non-Affiliate	3,397	15.10%		**Schedule 12 Expense (RTEP)**	$ 182,170,951	2020 TE AEP Zone Allocation	
	22,497.9			Total Zonal ATRR	2,278,532,488		
				Allocated to AEP %	84.90%		
				Allocated to AEP $	$ 1,934,462,222		
	AEP LSE Allocation						
12CP	MW	%					
AP - 12CP	5,082	29.57%		Allocated to APCo	$ 571,997,350		
OP - 12CP	7,324	42.62%		Allocated to OPCo	$ 824,421,172		
IM - 12CP	2,920	16.99%		Allocated to I&M	$ 328,666,155		
KP - 12CP	986	5.74%		Allocated to KPCo	$ 110,968,219		8,872,020
WPC - 12CP	551	3.21%		Allocated to WPCo	$ 62,062,784		
KGP - 12CP	323	1.88%		Allocated to KGPCo	$ 36,346,542		
Operating Company Sum	17,186	100.00%					
				Total Check	-		

Exhibit AEV R2
KPCO Residential EE Investment Payback Example

	No BSC Increase	Proposed BSC Increase
Residential Rate	0.12547	0.12265
Customers	133,596	133,596
Fixed Charge	$ 14.00	$ 17.50
Monthly Consumption kWh	1240	1240
Revenue Requirement	271,872,135	271,872,135
% fixed	8.26%	10.32%
<u>Energy Efficency Investment</u>		
Cost	$ 6.00	$ 6.00
Annual kWh Saved	30	30
Annual Cost savings	$ 3.82	$ 3.74
Payback	1.57	1.61

13 Days increase in payback

Exhibit AEV R3

Comparison of KY Residential Basic Service Charges Rates in Effect as of October 2020		
Electric Supplier	**Monthly Service Charge**	
Grayson RECC	$	21.25
Kenergy	$	18.20
Jackson Purchase Energy Corporation	$	16.40
Jackson Energy Cooperative	$	24.00
Meade County RECC	$	21.09
Inter-County Energy	$	15.20
Licking Valley RECC	$	9.00
Clark Energy	$	18.00
Bluegrass Energy	$	16.50
Big Sandy RECC	$	21.25
Farmers RECC	$	14.00
Shelby Energy Cooperative	$	15.00
Owen Electric Cooperative	$	20.00
Nolin RECC	$	13.50
Cumberland Valley Electric	$	12.00
South Kentucky RECC	$	12.82
Fleming-Mason Energy	$	15.00
Taylor County RECC	$	9.82
Pennyrile RECC	$	27.40
Warren RECC	$	18.80
West Kentucky RECC	$	25.90
Gibson EMC	$	27.50
Tri-County EMC	$	35.00
Kentucky Average	$	18.59
Min	$	9.00
Max	$	35.00

Exhibit AEV R4
Market Value of Typical Residential Solar System Output

Typical Test Year Residential System			
System Nameplate Capacity kW (AC)		8.84	
System PJM Capacity kW (AC)		3.36	
System kWh Output		13,374	
19/20 RPM BRA Price $/MW-day	$	100.00	
Average Hourly LMP $/MWh	$	29.36	
System Energy Value	$	393	
System Capacity Value	$	123	
Total	$	515	
Unitized Market Compensation $/kWh	**$**	**0.0385**	
NMS Compensation Rate $/kWh	**$**	**0.1033**	Res Typical bill current @1240 minus BSC

Exhibit AEV - R5 NMS II Updated Avoided Cost Rate Residential
NMS II Excess Generation Pricing -Residential

Full Solar Output Shape Value From Example Solar Plant					
				38,460	Total annual MWh from solar plant
	Solar Pk Reduction MW	Price	$ Value	$/kWh Price	
G Capacity	9.55	$ 100	$ 348,593	0.0091	
T Avoided Cost	5.51	$ 93,054	$ 512,424	0.0133	

Net Metering Shape Discount

Gen Capacity	**40.46%**	0.00367
T Avoided Cost	**21.48%**	0.00286

Cogen SPP Energy	$/kWh	
On Pk	0.0306	input from cogen spp rate design
Off Pk	0.0228	input from cogen spp rate design
Solar	0.02837	5/7 on-pk 2/7 off-pk

Updated NMS II Excess Generation Pricing		Originally Filed
Energy	0.02837	
Ancillary Services	0.00063	
G Capacity	0.00367	
T Fixed Cost	0.00286	
NMS Price for Excess Gen	**0.03553**	0.03659

Exhibit AEV - R5 NMS II Updated Avoided Cost Rate Residential
Example of Typical Customer and Typical Solar Install

Hour of the Day begin	end	Typical Res Customer 1240 kWh/Month	Typical NMS Solar System 8.84 kW-ICAP	Typical Solar Net Excess Gen	Summer Peak 5CP Excess %	Summer Peak 5CP Hours wt	Summer Peak 5CP Wtd Hours Excess	12 CP Excess %	12CP Hours Wt	12CP Hours Wt Wtd Excess Gen %
midnight	1 AM	42	-	-						
1	2 AM	41	-	-						
2	3 AM	41	-	-						
3	4 AM	41	-	-						
4	5 AM	44	-	-						
5	6 AM	49	-	-						
6	7 AM	49	-	-						
7	8 AM	49	5	-				0%	36%	0%
8	9 AM	51	27	-				0%	8%	0%
9	10 AM	50	67	17				25%	3%	1%
10	11 AM	51	106	55						
11	12 AM	52	133	81						
12	1 PM	53	145	92						
1	2 PM	55	148	93				63%	3%	2%
2	3 PM	58	146	88	60%	5%	3%	60%	6%	3%
3	4 PM	60	133	72	55%	15%	8%	55%	6%	3%
4	5 PM	62	105	43	41%	70%	29%	41%	31%	12%
5	6 PM	62	67	5	7%	10%	1%	7%	3%	0%
6	7 PM	61	28	-				0%	3%	0%
7	8 PM	61	6	-				0%	3%	0%
8	9 PM	60	-	-						
9	10 PM	55	-	-						
10	11 PM	49	-	-						
11	midnight	45	-	-						
		1,240	1,114	547		1	**40.46%**		1	**21.48%**

NMSII	Avg Monthly kWh
Net Billing kWh	648
Net Excess Gen	547
Netted kWh	592
NMS II vs Standard kWh	0.523
Typical NMS billable kWh	126

Exhibit AEV - R5 NMS II Updated Avoided Cost Rate Residential

Load Based PJM Ancillary Services $/MWh		
Sched 1-A: Sched, System Control, & Dispatch	$	0.06
Sched 2: Reactive Supply & Voltage Control	$	0.40
Sched 3: Regulation & Frequency Response	$	0.11
Sched 5: Synchronized Reserve	$	0.02
Sched 6: DA Operating Reserves	$	0.03
DA Scheduling Reserve	$	0.01
Total Avoided Cost for NMS II	$	0.63

Exhibit AEV R6 NMS II Updated Avoided Cost Rate for Commercial
Example of Typical Customer and Typical Solar Install - Commercial Class

Full Solar Output Shape Value From Example Solar Plant

38,460 Total annual MWh from solar plant

	Solar Pk Reduction MW	Price	$ Value	$/kWh Price
G Capacity	9.55	$ 100	$ 348,593	0.0091
T Avoided Cost	5.51	$ 93,054	$ 512,424	0.0133

Net Metering Shape Discount

Gen Capacity	**55.95%**	0.00507
T Avoided Cost	27.85%	0.00371

Cogen SPP Energy	$/kWh	
On Pk	0.0306	input from cogen spp rate design
Off Pk	0.0228	input from cogen spp rate design
Solar	0.02837	5/7 on-pk 2/7 off-pk

NMS II Excess Generation Pricing		Originally Filed
Energy	0.02837	
Ancillary Services	0.00063	
G Capacity	0.00507	
T Fixed Cost	0.00371	
NMS Price for Excess Gen	**0.03778**	0.03659

Exhibit AEV R6 NMS II Updated Avoided Cost Rate for Commercial

Example of Typical Customer and Typical Solar Install - Commercial Class

Hour of the Day		Typical Commercial Customer 3022 kWh/Month	Typical NMS Solar System 26.14 kW-ICAP	Typical Solar	Summer Peak 5CP	Summer Peak 5CP	Summer Peak 5CP	12 CP	12CP	12CP Hours Wt
begin	end	Load	Solar	Net Excess Gen	Excess %	Hours wt	Wtd Hours Excess	Excess %	Hours Wt	Wtd Excess Gen %
midnight	1 AM	97	-	-						
1	2 AM	95	-	-						
2	3 AM	94	-	-						
3	4 AM	97	-	-						
4	5 AM	103	-	-						
5	6 AM	117	-	-						
6	7 AM	128	-	-						
7	8 AM	142	15	-				0%	36%	0%
8	9 AM	150	79	-				0%	8%	0%
9	10 AM	154	198	44				22%	3%	1%
10	11 AM	154	313	159						
11	12 AM	155	393	239						
12	1 PM	155	428	273						
1	2 PM	154	436	282				65%	3%	2%
2	3 PM	151	432	281	65%	5%	3%	65%	6%	4%
3	4 PM	142	392	250	64%	15%	10%	64%	6%	4%
4	5 PM	135	311	176	57%	70%	40%	57%	31%	17%
5	6 PM	129	199	70	35%	10%	4%	35%	3%	1%
6	7 PM	125	83	-				0%	3%	0%
7	8 PM	120	17	-				0%	3%	0%
8	9 PM	115	-	-						
9	10 PM	108	-	-						
10	11 PM	103	-	-						
11	midnight	100	-	-						
		3,022	3,295	1,774		1	**55.95%**		1	**27.85%**

	Avg Monthly kWh
Net Billing kWh	1,429
Net Excess Gen	1,774
Netted kWh	1,593
NMS II vs Standard kWh	0.473
Typical NMS billable kWh	0

Exhibit AEV R6 NMS II Updated Avoided Cost Rate for Commercial

Load Based PJM Ancillary Services $/MWh		
Sched 1-A: Sched, System Control, & Dispatch	$	0.06
Sched 2: Reactive Supply & Voltage Control	$	0.40
Sched 3: Regulation & Frequency Response	$	0.11
Sched 5: Synchronized Reserve	$	0.02
Sched 6: DA Operating Reserves	$	0.03
DA Scheduling Reserve	$	0.01
Total Avoided Cost for NMS II	$	0.63

Exhibit AEV R7

Base Rate Revenue Targets	Residential	Total Commercial		Source
Demand	$ 115,987,406	$ 69,116,860	**a1**	Filed AEV Ex 1
Energy	$ 64,765,247	$ 36,705,780	**a2**	Filed AEV Ex 1
Dist Primary	$ 42,886,747	$ 26,667,375	**a3**	Filed AEV Ex 1
Dist Secondary	$ 20,643,519	$ 10,176,646	**a4**	Filed AEV Ex 1
Customer	$ 13,525,407	$ 5,334,606	**a5**	Filed AEV Ex 1
	$ 257,808,327	$ 148,001,267	**a=sum(a1-a5)**	
Test Year Billable Sales kWh	1,992,407,328	1,143,106,490	**b**	Filed Section II, Exhibit I
Test Year Class Avg Realization $/kWh	***$ 0.1294***	***$ 0.1295***	**c=a/b**	math
NMS Net Profile Allocation				
Non-Fuel G&T Demand	66.3%	55.8%	**d**	PK WP
Energy	52.3%	47.3%	**e**	Ex AEV R5&R6
Distribution	48.6%	34.5%	**f**	PK WP
Revenue Targets Reduced for NMS Profile	**Residential**	**Total Commercial**		
Demand	$ 76,899,650	$ 38,567,208	**g1=a1*d**	math
Energy	$ 33,872,224	$ 17,350,822	**g2=a2*e**	math
Dist Primary	$ 20,842,959	$ 9,200,244	**g3=a3*f**	math
Dist Secondary	$ 10,032,750	$ 3,510,943	**g4=a4*f**	math
Customer	$ 13,525,407	$ 5,334,606	**g5=a5**	math
	$ 155,172,991	$ 73,963,823	**g=sum(g1-g5)**	
Billable Sales Reduced for Netting	1,042,029,033	540,346,438	**h=b*e**	math
NMS Class Avg Realization $/kWh	***$ 0.1489***	***$ 0.1369***	**j=g/h**	math
Increase in Avg Realization (Rates)	15%	6%	**j > c**	

Exhibit AEV R7

Distribution Date	Hr Beg	Solar Output kW	Res Profile kW	Combined Profile kW
4/1/2019	8	2.60	3.12	0.52
5/28/2019	16	3.93	2.90	-
6/28/2019	15	2.75	2.99	0.24
7/19/2019	15	1.12	3.22	2.09
8/20/2019	15	5.32	3.15	-
9/13/2019	15	3.71	3.06	-
10/1/2019	15	4.71	2.72	-
11/13/2019	7	0.07	4.20	4.13
12/19/2019	8	0.00	3.78	3.78
1/22/2020	8	0.02	4.31	4.29
2/15/2020	8	2.11	4.18	2.07
3/1/2020	8	0.73	3.72	2.99
12CP Avg		2.26	3.45	1.68
				48.6%

Generation and Transmission Date	Hr Beg	Solar Output kW	Res Profile kW	Combined Profile kW
4/1/2019	6	0.01	3.03	3.02
5/28/2019	15	5.35	2.67	-
6/27/2019	15	3.97	2.95	-
7/19/2019	15	1.12	3.22	2.09
8/19/2019	15	1.03	2.95	1.91
9/11/2019	15	5.28	2.82	-
10/1/2019	15	4.71	2.72	-
11/13/2019	7	0.07	4.20	4.13
12/19/2019	7	-	3.66	3.66
1/22/2020	7	-	4.16	4.16
2/15/2020	7	-	4.08	4.08
3/1/2020	7	0.07	3.45	3.38
12CP Avg		1.80	3.33	2.20
				66.3%

Distribution Peaks Date	Hr Beg	Solar Output kW	Avg Profile kW	Combined Profile kW
4/1/2019	8	7.70	6.08	-
5/28/2019	16	11.63	5.15	-
6/28/2019	15	8.13	6.23	-
7/19/2019	15	3.32	6.08	2.76
8/20/2019	15	15.73	6.56	-
9/13/2019	15	10.97	6.48	-
10/1/2019	15	13.93	6.04	-
11/13/2019	7	0.20	5.11	4.92
12/19/2019	8	0.01	6.53	6.52
1/22/2020	8	0.07	7.62	7.56
2/15/2020	8	6.23	5.64	-
3/1/2020	8	2.16	5.68	3.52
12CP Avg		6.67	6.10	2.11
				34.5%

Generation and Transmission Date	Hr Beg	Solar Output kW	Avg Profile kW	Combined Profile kW
4/1/2019	6	0.03	4.53	4.50
5/28/2019	15	15.82	5.50	-
6/27/2019	15	11.72	6.27	-
7/19/2019	15	3.32	6.08	2.76
8/19/2019	15	3.06	6.40	3.35
9/11/2019	15	15.61	6.76	-
10/1/2019	15	13.93	6.04	-
11/13/2019	7	0.20	5.11	4.92
12/19/2019	7	-	5.96	5.96
1/22/2020	7	-	7.18	7.18
2/15/2020	7	-	5.71	5.71
3/1/2020	7	0.21	5.45	5.24
12CP Avg		5.32	5.92	3.30
				55.8%

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E-Signature Summary

Signer 1: Alex E. Vaughan (AEV)
November 03, 2020 10:49:26 -8:00 [52795C58678F] [167.239.221.83]
aevaughan@aep.com (Principal) (Personally Known)

E-Signature Notary: Sarah Smithhisler (SRS)
November 03, 2020 10:49:26 -8:00 [7E999162F4CC] [167.239.221.81]
srsmithhisler@aep.com
I, Sarah Smithhisler, did witness the participants named above electronically sign this document.

VERIFICATION

The undersigned, Alex E. Vaughan, being duly sworn, deposes and says he is a Director-Regulatory Pricing & Renewables for American Electric Power Service Corporation that he has personal knowledge of the matters set forth in the forgoing responses and the information contained therein is true and correct to the best of his information, knowledge and belief after reasonable inquiry.

Alex E. Vaughan
Signed on 2020/11/03 10:49:26 -8:00

Alex E. Vaughan

STATE OF OHIO	)
	) Case No. 2020-00174
COUNTY OF FRANKLIN	)

Subscribed and sworn to before me, a Notary Public in and before said County and State, by Alex E. Vaughan, this 3rd day of November 2020.

NOTARY PUBLIC
STATE OF OHIO
Sarah Smithhisler
Commission # 2019-RE-775042
Electronic Notary Public
State of Ohio
My Comm Exp. Apr 29, 2024
Notary Stamp 2020/11/03 11:49:26 PST 7E999162F4CC

S Smithhisler
Signed on 2020/11/03 10:49:26 -8:00

Notary Public

Notary ID Number: 2019-RE-775042