COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In The Matter Of: Electronic Application Of Kentucky Power Company For An Order Establishing the Form of Notice To Be Employed In Its Upcoming Application for A General Adjustment Of Rates And Other Relief.	: : : :	**Case No 2020-00174**

BRIEF OF ATTORNEY GENERAL AND KENTUCKY INDUSTRIAL UTILITY CUSTOMERS, INC.

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The Attorney General, by and through his Office of Rate Invention, ("AG") and Kentucky Industrial Utility Customers, Inc. ("KIUC") submit this Brief in support of their recommendations to the Kentucky Public Service Commission ("Commission" or "KPSC").

I. INTRODUCTION

On June 29, 2020, Kentucky Power filed its application in this case, requesting: 1) a base rate increase of $70.097 million; 2) an increase in the Environmental Surcharge ("ES") to reflect the proposed increase in the return on equity ("ROE") from 9.70% to 10.00%; 3) an increase in the Decommissioning Rider to reflect the proposed increase in the ROE from 9.70% to 10.00%; 4) recovery of 100% of increases in Load-Serving Entity ("LSE") Open Access Transmission Tariff ("OATT") transmission charges and credits (net expenses) incurred after the test year through the Purchased Power Adjustment ("PPA") rider ("Tariff PPA");[1] 5) termination of the Capacity Charge ("CC") tariff and the annual recovery of $6.2 million, contingent on no changes to the Company's base rate increase request;[2] 6) approval of a proposed

[1] The Company presently is allowed to recover 80% of increases in OATT LSE net expenses incurred after the last test year through the PPA Rider as the result of a settlement agreement in Case No. 2017-00179. The AG and KIUC opposed the recovery of increases in this expense through the PPA Rider in that proceeding, but agreed to the temporary modification of the PPA Rider in consideration of all provisions of the settlement agreement in that proceeding.
[2] The Capacity Cost Rider provides the Company with an enhanced return on equity on the costs incurred pursuant to the Rockport Unit Power Agreement ("UPA").

new Grid Modernization Rider ("GMR") to recover the costs of "distribution modernization investments or to improve the Company's reliability and resiliency," including the proposed new Advanced Meter Infrastructure ("AMI") meters and infrastructure, with an initial GMR rate increase of $1.105 million, which will be updated annually to recover the incremental revenue requirements of new distribution investments; 7) approval of a Certificate of Public Convenience and Necessity ("CPCN") to replace existing Advanced Meter Reading ("AMR") meters and infrastructure with new AMI meters and infrastructure; and 8) use of excess accumulated deferred income taxes ("EDIT") to offset the first year effect of the net of the proposed increase in the base revenue requirement, reduction in the CC tariff revenue requirement, and increase due to the new GMR.

The following table summarizes the effect of the AG-KIUC recommendations on the base rate, ES, Decommissioning Rider, Tariff PPA, and CC tariff revenue requirements compared to the Company's requests.[3]

[3] Direct Testimony of Lane Kollen ("Kollen Testimony") at 6:12-7:1.

Kentucky Power Company Revenue Requirement
Summary of AG and KIUC Recommendations
Case No. 2020-00174
For the Test Year Ended March 31, 2020
($ Millions)

	AG and KIUC Adjustments	Revenue Change
Base Rate Increase Requested by Company		**70.097**
AG and KIUC Rate Base Issues		
Utilize Rate Base Instead of Capitalization to Reflect Return On Component for Base Rates	0.608	
Set Cash Working Capital in Rate Base to $0	(1.660)	
Remove Prepaid Pension and Prepaid OPEB from Rate Base, Net of ADIT	(5.204)	
Remove Accounts Payables Balances from CWIP in Rate Base	(0.687)	
Remove Accounts Payable Balances from Prepayments in Rate Base	(0.007)	
AG and KIUC Operating Income Issues		
Remove Incentive Compensation Expense Tied to Financial Performance	(5.666)	
Remove SERP Expense	(0.205)	
Remove Company's Proforma Adjustment to Restate Rockport UPA Operating Ratio	(1.706)	
Restate State Income Expense Based on Kentucky-Only Income Tax Rate of 5%	(0.692)	
Remove EEI Dues for Covered Activities (Legislative and Regulatory Advocacy and Public Relations)	(0.048)	
AG and KIUC Cost of Capital Issues		
Reallocate the Mitchell Coal Stock Adjustment Proportionately Across Capital Structure	(0.705)	
Increase Short Term Debt and Set Debt Rate at 0.51%	(2.512)	
Reduce Long Term Debt Rate to Reflect Refinance of June 2021 Maturity	(0.793)	
Reduce Return on Equity from 10.0% to 9.0%	(7.576)	
Total AG and KIUC Adjustments to KPCo Base Rate Request		(26.855)
Maximum Base Rate Increase After AG and KIUC Adjustments		**43.242**
Capacity Charge Reduction Requested by Company		**(6.200)**
Grid Modernization Rate Increase Requested by Company		**1.105**
AG and KIUC Recommendation to Reject GMR		**(1.105)**
Environmental Surcharge Increase Based on Requested Return on Equity		**0.935**
Restate State Income Expense Based on Kentucky-Only Income Tax Rate of 5%	(0.204)	
Reduce Cost of Capital Based on AG and KIUC Recommendations	(3.420)	
Reduce Depreciation Expense on Rockport 2 SCR	(15.953)	
Total AG and KIUC Adjustments to ES Increase		**(19.577)**
Decommissioning Rider Increase Based on Requested Return on Equity		**0.349**
Restate State Income Expense Based on Kentucky-Only Income Tax Rate of 5%	(0.073)	
Reduce Cost of Capital Based on AG and KIUC Recommendations	(1.267)	
Total AG and KIUC Adjustments to Decommissioning Rider Increase		**(1.340)**
Maximum Net Rate Increase After AG and KIUC Adjustments		**17.410**

II. BACKGROUND AND PERSPECTIVE

Kentucky Power begins the first fourteen pages of its Post-Hearing Brief recounting sobering economic facts with which AG-KIUC firmly agree. The Company's service territory "has been in economic decline since 2008. This decline is widespread and has been primarily driven by the collapse of coal and steel production in the region."[4] "Unemployment and declining economic activity in the entire eastern Kentucky region have resulted in a concomitant population decline in 19 of the 20 counties comprising the Company's service territory. Between 2008 and 2019, population in the Company's service territory decreased by approximately 33,000 individuals or 7.6%."[5] "Between 2008 and 2019 the Company's total annual weather normalized sales fell by approximately 23.4%, or from approximately 7.4 gigawatt hours ("GWh") to 5.7 GWh. Customer usage since February 28, 2017, the end of the test year in the Company's last rate case, declined by more than 576 million kilowatt-hours."[6]

AG-KIUC also agree that the local management of Kentucky Power, including Mr. Mattison and before him, Mr. Satterwhite, has been doing an admirable job of community involvement, customer engagement, and economic development.[7] But the financial goals set by Kentucky Power's corporate parent run directly counter to these local efforts.

A base rate increase of $70.1 million – 14.73% system average – is not the answer to declining sales due to a depressed local economy.[8] It is counterproductive and will only make matters worse. A 14.73% system average base rate increase will only further drive down the depressed economy that the Company correctly describes, meaning even lower sales, a lower earned return for the Kentucky Power and the perceived need to raise rates even more - a death spiral.

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[4] Kentucky Power Post-Hearing Brief at 4.
[5] Id. at 5.
[6] Id. at 6.
[7] Id. at 7-13.
[8] Direct Testimony of Jason M. Stegall at 20; Application Section II, Filing Requirements Exhibit K at 1. The total proposed net change in rates after the elimination of the $6.2 million Rockport capacity charge and $1.1 million GMR increase is $65 million.

Kentucky Power's proposed base rate increase to the residential class is 17.97%.[9] And this proposed 17.97% residential base rate increase is coming on top of about the highest (if not the highest) residential rates in the Commonwealth. Using the rate calculator on Kentucky Power's website, the current monthly base rate charge for the average residential customer using 1,240 KWh/month is $135.64.[10] A 17.97% base rate increase would be $24.37 per month, or $292.44 per year. The Company's proposal to eliminate the Rockport capacity charge ($1.94 per month) helps a little. It reduces the proposed residential increase to $22.43 per month, or $269.16 per year.[11]

Using EDIT to offset the rate increase is sound and supported by the AG and KIUC, but it only masks the problem. EDIT is money that the Company owes customers. The Commission has already determined that customers will be refunded this prior tax overcollection with interest.

AEP's business model of growing earnings by growing rate base—which means even higher rates for the foreseeable future—cannot work here.

AEP is very direct to its investors about its business model. Corporate-wide AEP's forecasted "5%-7% EPS [earnings per share] growth is predicated on regulated rate base growth."[12] Rate base growth is a proxy for earnings growth. AEP intends to make money by spending money. Growing earnings by growing rate base and charging more per MWh may work in prosperous areas of the country, but not in eastern Kentucky. For example, 2020 and 2021 MWh sales are forecasted to grow by 0.8% and 2.7% in AEP Texas, but are forecasted to decline by (-6.4%) and (-1.6%) in 2020 and 2021 for Kentucky Power.[13]

AEP's plan is for Kentucky Power to realize compound annual earnings growth of 5% by

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[9] Direct Testimony of Jason M. Stegall at 20.

[10] *See* Attachment 1 to this Brief.

[11] As shown on the attached residential rate calculator, the total current average residential bill including all riders is $152.23 per month. Adding a monthly base rate increase of $24.37 and eliminating the Rockport capacity charge of $1.94 per month results in a new total residential total bill of $174.66.

[12] AG-KIUC Exhibit 1 (AEP November 2020 EEI Financial Conference Presentation) at 6 (reflecting that AEP is planning to grow earnings at a rate of 5-7%) and 25; Stenographic Tr. (November 17, 2020) at 49:8-10 (Q: "At the very bottom it says that five and seven percent earnings per share growth is predicated on regulated rate base growth. Does that mean you grow your earnings by growing your rate base?" Company witness Mattison: "That's what it says, yes.").

[13] AG-KIUC Exhibit 1 at 79 and 82.

increasing its rate base by 35% from $1.839 Billion in 2019 to $2.482 Billion in 2025.[14] And this is only Kentucky Power's directly-owned rate base. It does not include the enormous and ever-growing transmission rate base in Michigan, Indiana, Ohio, Virginia, West Virginia and Tennessee that is assigned to Kentucky Power through the AEP East Transmission Agreement. AEP's 2020-2024 capital budget forecast for new transmission spending in PJM is $9.772 Billion. Approximately 5.6% of the AEP LSE 85% share of these expenditures [approximately 15% is paid for by municipal load in the AEP zone], or $465 million, will be allocated to Kentucky Power.[15] Primarily because of out-of-state transmission rate base growth, Kentucky Power's transmission expense is expected to increase by $14 million in 2021.[16] And there is no end in sight.

Kentucky Power's ever-shrinking customer base cannot afford to pay higher rates caused by growing rate base simply to fulfill the investment targets of AEP. As noted above, Kentucky Power's weather-normalized retail sales are forecast to decline by (-6.4%) in 2020 and by another 1.6% in 2021.[17] Building on the evidence presented by the Company, this would be a weather-normalized sales decline of 31.4% from 2008 to 2021.

This is Kentucky Power's third base rate increase since 2014.[18] East Kentucky Power Cooperative ("EKPC") has not had a base rate increase since 2010. Both utilities have similar and in many places, overlapping service territories, although EKPC does have a growing industrial base primarily through multiple plant expansions at Nucor Steel Gallatin. But the biggest differences between the two utilities are the different incentives, capital structures, and tax status between an investor-owned utility and a customer-owned utility. A striking example of this difference is transmission cost. Under the AEP Transmission Agreement, Kentucky customers were assigned the AEP zonal transmission rate of $80,306/MW-year in 2020. The EKPC transmission rate for the same period was only $23,763/MW-

[14] Id. at 79.
[15] Direct Testimony of Stephen J. Baron at 17.
[16] Rebuttal Testimony of Alex E. Vaughn at 15.
[17] AG-KIUC Exhibit 1 at 79.
[18] Case No. 2014-00396, Case No, 2017-00179 and Case No, 2020-00174.

year.[19] Every asset has a natural owner. It is time to evaluate whether AEP is the owner best suited for the Kentucky Power service territory.

III. ARGUMENT

A. The Commission Should Reduce The Company's Requested Base Revenue Increase by $26.855 Million.

In order to establish just and reasonable rates for customers in Kentucky Power's service territory, several adjustments should be made to the Company's application, including multiple accounting adjustments, removal of unreasonable operating costs (incentive compensation, Edison Electric Institute dues, etc.), and reduction of Kentucky Power's authorized after-tax ROE to 9.0%.

IV. RATE BASE AND CAPITALIZATION ISSUES

A. Rate Base Is Superior to Capitalization to Calculate The Return On Component of The Base Revenue Requirement.

Kentucky Power proposes to use capitalization of $1.399 billion to calculate the return on component of the base revenue requirement.[20] The Commission should reject that proposal and instead should use rate base to calculate the return on component of the base revenue requirement.

As the Company itself agrees,[21] the use of rate base is more precise and accurate than capitalization to calculate the return on component of the base revenue requirement.[22] It allows the Commission to specifically review, assess, and quantify each of the costs that will earn a return, including those costs that are subtracted from rate base, such as accumulated deferred income taxes and negative cash working capital ("CWC"), to the extent that CWC is calculated using the lead/lag approach.[23] It also allows the

[19] AG-KIUC Exhibit 2.
[20] Section V, Schedule 1, line 18.
[21] Exhibit LK-2, Kentucky Power Response to AG-KIUC Item No. 2-10.
[22] Kollen Testimony at 10:4-5 and 10:17-19.
[23] Kollen Testimony at 10:5-9.

Commission to avoid a return on capitalization that is overstated due to timing differences, such as the issuance of long-term debt at favorable interest rates before it is necessary to fund construction or other cash requirements and the buildup of retained earnings at the end of a quarter mere days before dividends are declared and subsequently paid to the Company's parent company and sole shareholder.[24]

Kentucky Power provided two reconciliations between its capitalization and net investment rate base for the test year, one on a total Company basis and the other on a jurisdictional basis.[25] These reconciliations demonstrate that the use of capitalization is the less precise and accurate approach. The use of capitalization is essentially a "residual" approach based on total assets less total liabilities other than capitalization. Of course, not all assets and liabilities are cash costs or provided a return through the ratemaking process. Indeed, as the total Company reconciliation reflects, many assets and many liabilities from the Company's balance sheet accounts are not included in the Company's calculation of rate base.[26]

The Commission already uses rate base to calculate the return on component of the base revenue requirement for nearly all the investor-owned utilities (with the exceptions of the Company, Kentucky Utilities Company, and Louisville Gas & Electric Company) and for all of the Kentucky Power's riders that include a return on investment component.[27] This includes the Commission's recent change from capitalization to the use of rate base in the Duke Energy Kentucky, Inc. ("Duke") gas and electric cases, in which several Duke witnesses emphasized the superiority of the rate base approach.[28]

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[24] Kollen Testimony at 10:9-15.

[25] Exhibit LK-3, Kentucky Power Response to Staff Item No. 2-11; Sch 3-5 tabs in KPCO-R-KPSC_216_Attachment1 Excel workbook provided in Kentucky Power Response to Staff 2-16; Section II-Application Exhibit L.

[26] Kollen Testimony at 11:18-12:8.

[27] Kollen Testimony at 8:13-15; Kollen Testimony at 8:6-11.

[28] Kollen Testimony at 8:17-17; Direct Testimony of Sarah E. Lawler, Case No. 2018-00261 at 5 ("using gas rate base to calculate the revenue requirement is the simplest and most transparent method."); Direct Testimony of Amy B. Spiller, Case No. 2019-00271 at 25-26 ("Historically, the Company's electric base rates have been determined with reference to a return on capitalization. Although this methodology may have been appropriate in the past, another methodology is more common today. Specifically, and as evident in other Duke Energy Kentucky jurisdictions, a return-on-rate base approach provides a transparent and effective way to establish base rates. The Commission recently approved the return on rate-base approach for the Company's natural gas base rates in Case No. 2018-00261;" Direct Testimony of William Don Wathen, Jr., Case No. 2019-00271 at 11-12 ("use of rate base is a more precise method for measuring the Company's actual investment in facilities and equipment to provide utility service" and that "the rate base methodology is an easier and more conventional way to represent investment in utility plant that is not only accepted by this Commission, but throughout the country.").

In addition to adopting the rate base approach, the Commission should make at least four corrections to Kentucky Power's calculation of rate base to establish the parameters for this and future base rate proceedings. First, the CWC should be calculated using the lead/lag approach, or alternatively, set to $0. Second, the prepaid pension asset and prepaid OPEB asset are not cash assets and should not be included in rate base. Third, the construction work in progress ("CWIP") included in rate base should be reduced by the accounts payable related to the CWIP. Fourth, the prepayments should be reduced by the accounts payable related to those prepayments.[29] Close review of Kentucky Power's calculation is warranted given that the Commission has not used rate base directly to calculate the return on component of the Company's base revenue requirement.[30]

1. Cash Working Capital

The Company calculated CWC of $20.446 million in its rase bate calculation using the one-eighth O&M expense formula approach.[31] But the one-eighth O&M expense formula approach is outdated and unacceptably inaccurate. The result of this formula mathematically can only be positive, regardless of whether the customers provide the utility cash working capital funds, in which case, the result conceptually should be negative, not positive. In addition, the result of this formula approach tends to be overstated because it is driven by the level of O&M expense and fails to measure accurately the investment made either by the utility or its customers.[32]

In contrast to the formula approach, the lead/lag approach provides an accurate and objective quantification. The lead/lag approach correctly measures and weights the timing of the delays in converting revenues into cash and the prepayments or delays in disbursing cash for expenses. A lead/lag study is required to statistically and objectively sample and measure the leads and lags for the revenues

[29] Kollen Testimony at 12:22-13:5.
[30] Kollen Testimony at 12:14-18.
[31] Section V, Schedule 4, line 43.
[32] Kollen Testimony at 13:14-22.

and expenses, weight them on a dollar-day basis, and then quantify the net investment. The result is a net utility investment if it is positive or a net customer investment if the result is negative.[33]

In a recent Atmos Energy Corporation ("Atmos") rate case, the Commission found that the lead/lag approach provided a more accurate result than the one-eighth O&M expense formula approach.[34] In that case, the utility requested CWC calculated using the one-eighth O&M expense formula approach, but provided a calculation using the lead/lag approach in response to discovery.[35] The Commission ultimately chose the lead/lag approach, explaining that "[w]hile the one-eighth O&M methodology is a reasonable estimate of cash working capital absent a lead/lag study, Atmos's lead/lag study is part of the record of this proceeding and more accurately reflects the working capital needs of Atmos."[36]

The Commission has also found that the lead/lag approach will result in negative CWC when the utility's receivables are sold and the revenue lag is minimal.[37] In the most recent Duke electric case,[38] the utility sought to calculate CWC using the one-eighth O&M expense formula approach.[39] However, like Kentucky Power, Duke sells its receivables to a third party.[40] In doing so, Duke substantially accelerates the conversion of the receivables into cash and significantly reduces the revenue lag (the number of days between the date the meter is read and the date customer payments are available in cash) compared to other utilities that do not sell their receivables and finance them for 30 or more days until they receive payment and the cash is available.[41] Because such a receivable sales approach can reduce revenue lag to little more than one day, Duke's use of the one-eighth O&M expense formula approach likely would have

[33] Kollen Testimony at 14:1-8.
[34] *In Re: Application Of Atmos Energy Corporation For An Adjustment Of Rates And Tariff Modifications,* Case No. 2017-00349, Order (May 3, 2018) ("Atmos Order") at 16-17.
[35] Atmos Order at 16-17.
[36] Id.
[37] Kollen Testimony at 16:1-4.
[38] *In Re: Electronic Application Of Duke Energy Kentucky, Inc. For 1) An Adjustment Of The Electric Rates; 2) Approval Of New Tariffs; 3) Approval Of Accounting Practices To Establish Regulatory Assets And Liabilities; And 4) All Other Required Approvals And Relief*, Case No. 2019-00271.
[39] *See, e.g.,* Direct Testimony of Lane Kollen, Case No. 2019-00271 at 11.
[40] Id. at 16; Kentucky Power 2019 Form 1 at 123.61. Kentucky Power sells its receivables to AEP Credit, Inc.
[41] Direct Testimony of Lane Kollen, Case No. 2020-00179 at 15:1-7; Exhibit LK-7; Kentucky Power Response to AG-KIUC Item No. 2-6.

resulted in negative CWC. Consequently, rather than adopt the utility's proposal, the Commission ultimately set CWC at $0.[42]

During the discovery process, AG-KIUC asked Kentucky Power to provide a CWC calculation using the lead/lag approach, but the Company would not.[43] Kentucky Power has the data necessary to perform such a study, and American Electric Power ("AEP") routinely provides such calculations and lead/lag studies in rate proceedings in other jurisdictions, including its utilities in Texas, Ohio, West Virginia, Virginia, Oklahoma, Arkansas, and Louisiana.[44] Kentucky Power also acknowledges that it is the only party in this proceeding that has the data necessary to perform such a study.[45] In other words, AEP has the expertise to perform a CWC calculation using the lead/lag approach or could have retained a consultant to do so, but chose not to in this proceeding. Duke similarly refused to provide a lead/lag CWC study using the lead/lag approach; however, that did not ultimately sway the Commission's decision.[46]

Kentucky Power provided no empirical support that the one-eighth O&M expense formula approach is more accurate, likely because there is none.[47] Accordingly, the Commission should include $0 for CWC in rate base due to the absence of a correct calculation of CWC using the lead/lag approach, which likely would be negative. The Commission should also direct the Company to provide a calculation of CWC using the lead/lag approach in future base rate proceedings. The effect is a reduction of $1.660 million in the base revenue requirement.[48]

The Commission should also set CWC in the ES to $0 in the absence of a correct calculation of CWC using the lead/lag approach, which likely also would be negative. The ES revenue requirement presently includes a calculation of CWC using the one-eighth O&M expense formula approach, although

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[42] Id. at 16:4-12.
[43] Exhibit LK-4; Kentucky Power Response to AG-KIUC Item No. 2-1.
[44] Kollen Testimony at 14:10-16; Exhibit LK-5; Kentucky Power Responses to AG-KIUC Item Nos. 2-2 and AG-KIUC 2-7.
[45] Kollen Testimony at 14:16-18; Exhibit LK-6; Kentucky Power Response to AG-KIUC Item No. 2-3.
[46] Kollen Testimony at 16:10-12.
[47] Exhibit LK-8; Kentucky Power Response to AG-KIUC Item No. 2-9.
[48] Kollen Testimony at 17:1-8.

it is a relatively small amount and the effect on the ES revenue requirement is less than $0.030 million. The Company sells its customer receivables without consideration of whether the receivables were due to the base rate tariffs or any of the rider tariffs. Given that fact, the one-eighth O&M expense formula approach is no more appropriate or reasonable for the ES or any other rider tariff than it is for the base revenue requirement.[49]

2. Prepaid Pension and OPEB Assets

Kentucky Power erred by including $44.206 million ($44.879 million total Company) for a prepaid pension asset and $19.872 million ($20.175 million total Company) for a prepaid OPEB asset in rate base.[50] While the Company recorded those amounts for accounting purposes in account 1650010 and account 1650035 for pension and OPEB, respectively, the Company also recorded equivalent negative amounts (contra-assets) in accounts 1650014 and 1650037 for the prepaid pension asset and the prepaid OPEB asset, respectively, as the following Kentucky Power table reflects.[51]

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[49] Kollen Testimony at 17:10-20.

[50] These amounts are shown in Kentucky Power's Response to Staff Item No. 2-11, which provides a reconciliation between capitalization and rate base on a total Company basis.

[51] Kollen Testimony at 18:5-16; Exhibit LK-9, Kentucky Power Response to AG-KIUC Item No. 2-17.

Kentucky Power Company
Pension and OPEB Balances as of December 31, 2019

Account	Description	Pension	OPEB
1650010/ 1650035	Prepayment - Contributions	$45,500,106	$19,143,276
1650014/ 1650037	ASC 715 Prepayment Reclass	(45,500,106)	(19,143,276)
1290000/ 1290001	ASC 715 Trust Funded Positions (Assets)	-	23,421,499
2283016/ 2283006	ASC 715 Trust Funded Position (Liabilities)	(1,611,500)	-
1823165/ 1823166	ASC 715 - Regulatory Asset	45,940,166	(2,107,133)
1900010/ 1900011	ASC 715 - ADFIT Asset	246,002	(455,929)
2190006/ 2190007	ASC – 715 Other Comprehensive Income	925,438	(1,715,161)
	Total ASC 715 Entries	-	-
	Total Pension and OPEB Accounts	45,500,106	19,143,276
	Total Pension and OPEB Excluding 165 Accounts	$ 45,500,106	$ 19,143,276

This table includes *all* of the pension and OPEB balance sheet amounts, not only the amounts in the four prepaid pension and prepaid OPEB accounts on a total Company basis as of December 31, 2019.

The sum of the prepaid pension amounts in accounts 1650010 and 1650014 is $0 and the sum of the prepaid OPEB amounts in accounts 1650035 and 1650037 is $0 for accounting and financial reporting purposes. In other words, there is no prepaid pension asset and there is no prepaid OPEB asset unless one ignores the negative amounts in accounts 1650014 and 1650037, which is what the Company did in its calculation of rate base.

The Company's failure to include the negative prepaid pension and negative prepaid OPEB amounts in accounts 1650014 and 1650037 as subtractions from rate base is a mistake. First, the two are interrelated - either both the positive and negative accounts should be reflected or both should be ignored in the calculation of rate base. Regardless, the correct effect on rate base should be $0. Second, the Company's accounting reflected in these four accounts is not required, defined, or described by Generaylly

Accepted Accounting Principles ("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.[52]

The Company's accounting for the prepaid pension asset and prepaid OPEB asset demonstrates that it does *not* finance these assets. The amounts in the four 165 accounts net to $0, so there is no financing requirement associated with those accounts.[53] The origin of these net regulatory assets dates to the adoption of Statement of Financial Accounting Standards ("SFAS") Nos. 87 (Pensions) and 106 (OPEBs) more than twenty years ago, which changed the accounting rules to require that pension and OPEB assets and liabilities be recorded on the balance sheet. Utilities were directed to record the difference between the assets and liabilities as a regulatory liability (if the liabilities exceeded the assets) or as a regulatory asset (if the assets exceeded the liabilities). There was and has been no outlay of cash or financing for these regulatory assets.[54] This may explain why Duke did not include either a prepaid pension asset or a prepaid OPEB asset or regulatory asset related to the pension and OPEB assets and liabilities in rate base in its most recent gas and electric base rate proceeding when it changed to the rate based approach from the capitalization approach.[55] Because the net regulatory assets are merely accounting entries that have not been financed, they should not be included in rate base. The effect of excluding the prepaid pension asset and prepaid OPEB asset from rate base is a reduction of $5.204 million in the base revenue requirement.

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[52] There are no defined prepaid OPEB asset or prepaid pension asset subaccounts listed or described in the FERC Uniform System of Accounts. *See* 18 C.F.R. Pt. 101. The Company's 1650035 and 1650010 subaccounts are uniquely defined and used by the Company and other AEP operating utilities for recordkeeping purposes and to support their attempts to include the asset amounts in rate base.
[53] Kollen Testimony at 21:4-8.
[54] Kollen Testimony at 21:18-22:2.
[55] Kollen Testimony at 22: 4-9; Schedule B-1 from Duke Energy Kentucky (gas) rate base in Case No. 2018-00261; Schedule B-1 from Duke Energy Kentucky (electric) rate base in Case No. 2019-00271.

If the Commission uses rate base in lieu of capitalization and does not correct the Company's calculation of rate base to exclude the prepaid pension asset and prepaid OPEB asset, a related error still needs to be corrected – Kentucky Power failed to exclude the asset ADIT related to the pension and OPEB contra-asset accounts. Kentucky Power agrees that this error should be corrected if the Commission includes the prepaid pension asset and prepaid OPEB asset in rate base without the offsetting negative prepaid pension asset and prepaid OPEB asset in accounts 1650014 and 1650037.[56]

3. Accounts Payable – Construction Work In Progress

Kentucky Power included CWIP of $87.885 million in rate base.[57] But while the Company had $8.46 million in accounts payables related to CWIP outstanding on a 13-month average basis during the test year,[58] it did not offset CWIP by the accounts payable outstanding related to CWIP.[59] This was an error. The CWIP should be reduced by the related accounts payable outstanding. Kentucky Power has not financed the portion of the CWIP that has related accounts payable outstanding; the Company's vendors have. The effect is a reduction of $0.687 million in the base revenue requirement.[60]

4. Accounts Payable - Prepayments

Kentucky Power included other prepayments of $1.807 million in rate base.[61] But the Company had $0.084 million in accounts payables outstanding related to those prepayments on a 13-month average basis in the test year.[62] And again, the Company did not offset the prepayments by the accounts payable outstanding related to those prepayments, as they should have.[63] Kentucky Power has not financed the portion of the prepayments that has related accounts payable outstanding; the Company's vendors have.[64]

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[56] Exhibit LK-10; Kentucky Power Response to AG-KIUC Item No. 2-16.
[57] Section V, Schedule 4, line 44.
[58] Exhibit LK-11, Kentucky Power Response to Staff Item No. 2-10, Attachment 1.
[59] Kollen Testimony at 23:9-18.
[60] Kollen Testimony at 23:20-24:6
[61] Section V, Schedule 4, line 232.
[62] Exhibit LK-11; Kentucky Power Response to Staff Item No. 2-10, Attachment 1.
[63] Kollen Testimony at 24:20-25:1.
[64] Kollen Testimony at 25:3-8.

Accordingly, the Commission should reduce the prepayments by the related accounts payable outstanding. The effect is a reduction of $0.007 million in the base revenue requirement.[65]

B. If The Commission Adopts The Proposed Capitalization Approach, Then Several Corrections Are Still Necessary.

Even if the Commission continues to use capitalization for the return on component of the base revenue requirement, numerous costs should be removed or added to capitalization so that it is consistent with the appropriate ratemaking recovery of the return on these costs. Some are related to non-utility activities, some are related to surcharges and either are or should be included in the costs recovered through those surcharges, and some are not specifically allowed a return. Some simply vary from positive to negative amounts over time and are not appropriate to include in base rates under the assumption that they generally will net to zero over time. These costs include the following:[66]

[65] Kollen Testimony at 25:10-11.
[66] Kollen Testimony at 25:16-26:3.

Adjustments to Capitalization ($000's)		
131	Cash	629
134	Cash Equivalents	382
142	PJM Trans Enhancement Refund	644
142	AR Peoplesoft Billing-Cust	1,395
142	AR Long-Term Customer	3,133
146	Intercompany Receivables	20,942
172	Rents Receivable	3,836
173	Accrued Utility Revenues	11,543
175	Energy Trading	3,457
182.3	SFAS 112 Postemployment Benef	3,437
182.3	DSM Incentives	4,514
182.3	Unrealized Loss on Fwd Commitments	1,831
182.3	Net CCS FEED Study Costs	707
182.3	IGCC Pre-Construction Costs	1,078
182.3	BS1OR Under Recovery	(2,107)
182.3	BSRR Unit 2 O&M	1,166
182.3	Deferred Dep - Environmental	5,559
182.3	Def Depr-Big Sandy Unit 1 Gas	1,039
182.3	Def Prop Tax-Big Sandy U1 Gas	359
183	Prelimin Surv & Invesgtn Chrgs	1,105
186	Billings and Deferred Projects	363
186	Deferred Expenses	5,636
234	Intercompany Payables	(21,938)
244	Energy Contracts Current	(1,931)
	Total	46,779

The effect of this recommendation is a reduction, net of ADIT for applicable items, of $34.345 million to adjusted capitalization and a reduction of $2.789 million in the base revenue requirement. However, these adjustments to capitalization are necessary only if the Commission calculates the return on component of the revenue requirement using capitalization.[67]

[67] Kollen Testimony at 27:1-6.

V. OPERATING INCOME ISSUES

A. The Commission Should Deny Recovery Of Incentive Compensation Expense Tied to AEP's Financial Performance.

The Company included $5.631 million in incentive compensation expense tied to AEP's financial performance. Of this amount, $1.164 million was incurred pursuant to the AEP Long Term Incentive Plan ("LTIP") and $4.467 million was incurred pursuant to the AEP Incentive Compensation Plan ("ICP"),[68] after exclusions of amounts billed to the co-owner of the Mitchell plant.[69] The sum of these amounts after gross-up for bad debt expense and regulatory fees is $5.666 million.

In addition, the Company in an notable insult to the Commonwealth, has included a new component to its 2020 LTIP performance share incentives ("PSI") known as the Non-Emitting Generating Capacity Goal ("NEGCG"), in which it seeks to force *customers* in a coal-producing state to provide funding for a *shareholder* initiative designed to shut-down coal-fired power plants. Kentucky Power and its parent company have clearly lost sight of the fact that as coal-mining in the Kentucky Power territory decreases, the Company's electric demand decreases more and more, thus driving the need for additional rate increases.[70] The Commission should reject the NEGCG as it is clearly tone-deaf to the needs of Kentucky Power's customers and the Commonwealth as a whole.

The NEGCG management incentive is another example why it may be time to evaluate whether AEP is the natural owner of the Kentucky Power service territory. AEP's Wall Street-driven Environmental, Social and Governance ("ESG") goal of a 70% reduction in carbon emissions by 2030[71]

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[68] Exhibit LK-12; Section V, Exhibit 2 Adjustment WP 27; Kentucky Power Response to AG-KIUC Item No. 1-26; Kentucky Power Response to AG-KIUC Item No. 2-18. The Company provided the incentive compensation expense included in the test year revenue requirement incurred directly by the Company and incurred by AEP Service Corporation and allocated to the Company. The Company also provided calculation distinctions in Kentucky Power Response AG-KIUC 1-27, a copy of which is provided in a separate exhibit as noted below.
[69] Kollen Testimony at 27:10-20.
[70] See generally cross-examination of KPCo witness Carlin by attorney Kurtz, Stenographic Transcript (November 19, 2020) at 99-100.
[71] AG-KIUC Exhibit 1 at 42.

would be enhanced by divesting 780 MW of coal generation (Mitchell) and 285 MW of gas generation (Big Sandy). A different owner may not have the same Wall Street-driven ESG goals.

The AEP LTIP incentivizes AEP executives and managers to enhance shareholder value, to the detriment of customers. For instance, if AEP executives and managers achieve or exceed the LTIP target metrics for total shareholder returns ("TSR") and earnings per share ("EPS"), then they are rewarded with additional compensation.[72] The LTIP incentive compensation consisted of PSIs and restricted stock units ("RSUs") during the test year.[73] The LTIP PSI incentive compensation in 2019 was based only on AEP's EPS and TSR target metrics, both of which are measures of AEP's financial performance. As discussed above, the 2020 LTIP PSI was expanded slightly to include a target metric for the NEGCG, under which executives and managers can receive financial reward for reducing AEP's emissions via fossil fuel plant retirements, demand-side management, or construction of new renewable energy resources.[74] The LTIP RSU incentive compensation is based on the stock price of AEP at the grant date.[75] The stock price, by definition, is a measure of AEP's financial performance.[76]

The AEP ICP was implemented to reward employees for achieving or exceeding targets for AEP's EPS as well as certain operations and safety metrics, weighted 70% to AEP's EPS and 30% to the other target metrics during 2019 and 100% to AEP's EPS starting in 2020.[77] The Company incurred $4.467 million in ICP incentive compensation expense in the test year, all of which is tied to the achievement of AEP's EPS starting in 2020.[78]

The Commission should exclude the AEP LTIP and ICP incentive compensation expense tied to AEP's financial performance from the Company's revenue requirement. The Commission historically

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[72] Exhibit LK-13; Kentucky Power Response to AG-KIUC Item No. 1-27.
[73] "Units" are similar to shares of AEP common stock, but have no voting rights.
[74] Stenographic Transcript (November 19, 2020) at 95-101.
[75] Tr. (November 19, 2020) at 9:41:55; Stenographic Tr. (November 19, 2020) at 86.
[76] Kollen Testimony at 38:3-14.
[77] Exhibit LK-14; Response to Staff 4-24.
[78] Kollen Testimony at 28:16-29:2.

has disallowed and removed incentive compensation expenses from the revenue requirement that were incurred to incentivize the achievement of shareholder goals as measured by financial performance, not incurred to incentivize the achievement of customer and safety goals. That is because the achievement of AEP LTIP and ICP target metrics tied to financial performance benefits shareholders to the detriment of customers in rate proceedings such as this. The vast majority of AEP LTIP and the entirety of AEP ICP were incurred starting in 2020 to achieve shareholder goals and was not directly tied to the achievement of regulated utility service requirements.[79]

In the most recent Company base rate proceeding, the Company agreed to forego recovery of all incentive compensation expense tied to financial performance as one term in a settlement agreement, which the Commission accepted.[80] In the prior Company base rate proceeding, the Commission specifically disallowed incentive compensation expense incurred to achieve shareholder goals, explaining:

> Incentive criteria based on a measure of EPS, with no measure of improvement in areas such as service quality, call-center response, or other customer-focused criteria are clearly shareholder oriented. As noted in Case No. 2013-00148, the Commission has long held that ratepayers receive little, if any, benefit from these types of incentive plans. It has been the Commission's practice to disallow recovery of the cost of employee incentive plans that are tied to EPS or other earnings measures and we find that Kentucky Power's argument to the contrary does nothing to change this holding as it is unpersuasive.[81]

Likewise, in its order in Kentucky-American Water Company Case No. 2010-00036, the Commission disallowed incentive compensation expense tied to "financial goals that primarily benefited shareholders."[82]

Again, in its Order in Atmos Case No. 2013-00148, the Commission explained that "[i]ncentive criteria based on a measure of EPS, with no measure of improvement in areas such as safety, service quality, call-center response, or other customer-focused criteria, are clearly shareholder-oriented. As

[79] Kollen Testimony at 29:4-15.
[80] Case No. 2017-00179, Order (Jan. 18, 2018) at 13-15.
[81] Case No. 2014-00396, Order (June 22, 2015) at 25.
[82] Case No. 2010-00036, Order (Dec. 14, 2010) at 32.

noted in the hearing on this matter, the Commission has long held that customers receive little, if any, benefit from these types of incentive plans. It has been the Commission's practice to disallow recovery of the cost of employee incentive plans that are tied to EPS or other earnings measures."[83] Thus, the LTIP and ICP expense tied to EPS and total shareholder return should be borne by shareholders, not customers.

Further, incentive compensation incurred to incentivize AEP financial performance also provides the Company's executives, managers, and employees a direct incentive to seek greater and more frequent rate increases from customers in order to improve AEP's EPS and TSR. The greater the rate increases and revenues, the greater AEP's EPS and TSR and the greater the incentive compensation expense. Thus, there is an inherent conflict between achieving lower rates for customers on the one hand and achieving greater financial performance for shareholders and greater incentive compensation for executives, managers, and other employees on the other hand. Thus, all such expenses should be allocated to shareholders, not to customers.[84]

Finally, the Company's request to embed these expenses in the revenue requirement tends to be self-fulfilling. The additional revenues ensure that the expense is recovered regardless of the Company's actual performance and regardless of its operational and safety performance. Thus, the expenses should be directly assigned to AEP shareholders, not customers.[85] The Company's requests for recovery of LTIP and ICP expense tied to EPS and total shareholder return fall clearly within the disallowance precedent and should be allocated to shareholders and not recovered from customers.

B. The Commission Should Deny Recovery of Supplemental Executive Retirement Plan Expense.

The Company included $0.006 million in Supplemental Executive Retirement Plan ("SERP") expense for its employees and another $0.199 million in affiliate charges from AEP Service Corporation

[83] No. 2013-00148, Order (April 22, 2014) at 20.
[84] Kollen Testimony at 30:19-31:5.
[85] Kollen Testimony at 31:6-10.

("AEPSC") in the test year base revenue requirement despite the Commission's disallowance of SERP expense in prior cases.[86] For instance, in Case No. 94-355, the Commission found:

> The Attorney General's second adjustment would reduce expenses by $41,789 for SERP costs directly incurred by Cincinnati Bell because the Commission has previously removed from cost of service the cost of plans when benefits for highly compensated employees exceed the pension plan for all employees." Not surprisingly, we find the adjustment should be accepted.[87]

The policy rationale for exclusion of SERP costs is the same as that cited by the Commission more recently to deny recovery of 401(k) plan matching contributions that a utility makes on behalf of employees who also participate in a defined benefit plan.[88] For example, in Case No. 2016-00169,[89] the Commission stated: "The Commission believes all employees should have a retirement benefit, but finds it excessive and not reasonable that Cumberland Valley continues to contribute to both a defined-benefit pension plan as well as a 401(k) plan for salaried employees."[90] Moreover, the fact that SERP expense is deductible to the parent company when SERP expense is paid should highlight the need to insure that no portion of SERP should be forced onto customers.[91]

In this proceeding, the Company's desire to recover SERP expenses from customers, instead of shareholders, is an attempt to make an end-run around the Commission's prohibition against recovery of excessive expenses incurred pursuant to multiple retirement plans. The Commission's existing policy of excluding expenses for multiple supplemental retirement programs available to salaried employees is even more crucial in the context of SERP, which is available exclusively to highly-compensated executives.[92]

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[86] Exhibit LK-15; Kentucky Power Response to AG-KIUC Item No. 1-29.
[87] *In Re Application of Cincinnati Bell Telephone Co*., Case No. 94-355 at 16. *See also, In Re Application of Louisville Gas & Electric Co*., Case No. 90-158, Order (Dec. 21, 1990) at 27.
[88] *See, e.g., In Re Electronic Application of Louisville Gas & Elec. Co. for an Adjustment of Rates, etc.,* Case No. 2016-00371, Order (June 22, 2017) at 16-17.
[89] *In Re Application of Cumberland Valley Electric, Inc. for a General Adjustment of Rates*, Case No. 2016-00169, Order (Feb. 6, 2017) at 10.
[90] Id. at 10.
[91] Stenographic Transcript at 95.
[92] Kollen Testimony at 32:16-22.

Consequently, the Commission should disallow SERP expense for the reasons that it has cited in prior Orders.

C. The Commission Should Reject Kentucky Power's Proposed Test-Year Adjustment To Increase the Rockport UPA Demand Expense.

Kentucky Power proposes a post-test year adjustment in the Rockport UPA demand expense to reflect an increase in the operating ratio after the Rockport 2 SCR was placed in service in June 2020 and transferred to plant in service from CWIP.[93] This adjustment increases demand expense by $1.696 million and the base revenue requirement by $1.706 million.[94]

The Commission should instead direct Kentucky Power to defer the additional expense and accumulate it in the Rockport UPA regulatory asset, then subsequently recover it as an increase in the amortization expense through the PPA Rider starting in December 2022 coincident with the termination of the Rockport UPA.[95] It is not reasonable to further increase the recovery of the Rockport UPA expense through the base revenue requirement for the next two years. A mechanism already exists to defer and amortize a portion of the Rockport UPA expense in order to mitigate the rate increases through 2022 and the rate reduction that otherwise will occur in December 2022. Moreover, the deferral of this post-test year increase in expense is consistent with Mr. Kollen's recommendation to defer the interest expense resulting from a post-test year adjustment in the cost of debt. In this manner, the two post-test year adjustments will be addressed through deferrals in order to mitigate the effects of these costs on the base revenue requirement in this proceeding, but still will provide the Company full recovery, albeit at later dates, and do so without harming customers.[96] Finally, witness Vaughan expressly stated the Company agrees with this proposal.[97]

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[93] Direct Testimony of Alex Vaughan at 48.
[94] Direct Testimony of Alex Vaughan at 49.
[95] Kollen Testimony at 33:14-19
[96] Kollen Testimony at 34:3-9.
[97] Vaughan Rebuttal 7:12-16.

D. The Commission Should Reject Kentucky Power's Proposed Blended State Income Tax Rate.

Kentucky Power proposes a state income tax rate of 5.8545% - a rate substantially in excess of the Kentucky state income tax rate of 5.00%.[98] Kentucky Power's state income tax rate of 5.8545% is a blended rate resulting from state income taxes apportioned to the Company from: 1) Illinois with an income tax rate of 9.50%; 2) Michigan with an income tax rate of 6.00%; 3) West Virginia with an income tax rate of 6.50%; and 4) Kentucky with its state income tax rate of 5.00%.[99]

The use of Kentucky Power's proposed blended state income tax rate is unreasonable. Kentuckians should not be subjected to the financial consequences of decisions made by policymakers in other jurisdictions. Kentuckians have no recourse against those policy-makers if they find their decision-making objectionable. Therefore, the Company's base and rider revenue requirements in Kentucky should be based on Kentucky state income tax rates regardless of whether the taxable income for all or some of the AEP entities is included in other states' income tax returns and then apportioned to that state based on some allocation factor.[100] The fact that AEP entities operate in numerous states should be irrelevant for ratemaking purposes and should not affect the state income tax rate or the state income tax expense included in the Company's base and rider revenue requirements.[101]

The Commission should treat the Company as a standalone entity for the calculation of state income tax expense in the same manner that it treats the Company as a standalone entity for the calculation of federal income tax expense for ratemaking purposes.[102] In prior cases, the Commission declined to include AEP consolidated tax savings, declined to reflect tax savings from interest on the debt AEP has used to finance its equity investment in the Company in the calculation of federal income tax expense for

[98] Section V Schedule 2 Workpaper S-2 page 2 of 3.
[99] Section V Schedule 2 Workpaper S-2 page 2 of 3.
[100] Kollen Testimony at 35:1-6.
[101] Kollen Testimony at 35:7-9.
[102] Kollen Testimony at 35:10-13.

ratemaking purposes, and declined to reflect the parent company loss adjustment ("PCLA") tax benefit for ratemaking purposes even though it actually was allocated from AEP to the Company and reflected as a reduction in its per books income tax expense.

In its Order in Case No. 2014-00396, the Commission rejected the AG's recommendation to include the parent company loss adjustment as a reduction to the Company's federal income tax expense and base revenue requirement, stating:

> The Commission finds that the AG's proposal to include the PCLA in Kentucky Power's federal income tax expense is inappropriate. This recommendation, if adopted, would represent a significant departure from over 25 years of the Commission's established and balanced policy prohibiting affiliate cross-subsidization. Therefore, the "stand-alone" approach the Commission has historically used shall be used to allocate income tax liabilities for Kentucky ratemaking purposes. Accordingly, we deny the AG's proposed adjustment for ratemaking purposes. *(footnote omitted).*[103]

The Commission should calculate Kentucky Power's state income expense using the Kentucky state income tax rate for base and rider revenue requirement purposes. The effect of doing so reduces the gross revenue conversion factor from 1.35273 to 1.34056 and results in a reduction of $0.692 million in the base revenue requirement, a reduction of $0.204 million in the ES revenue requirement, and a reduction of $0.073 million in the Decommissioning Rider revenue requirement.[104]

E. The Commission Should Deny Recovery of Edison Electric Institute Dues.

In discovery, Kentucky Power supplied a copy of the invoice submitted by Edison Electric Institute ("EEI") to AEPSC showing that a total of $2.637 million related to regular membership and industry issues was billed to AEPSC.[105] The Company's allocated share of that amount was $0.088 million.[106] The supplied invoice included footnotes stating that 13% of membership dues and 24% of industry dues

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[103] Case No. 2014-00396, Order (June 22, 2015) at 23.
[104] Kollen Testimony at 36:13-23.
[105] Kollen Testimony, Exhibit LK-16; Kentucky Power Response to AG-KIUC Item No. 2-44, Attachment 1 at 3.
[106] West Rebuttal Testimony at 16, Fig. 2.

were related to "influencing legislation." There were no other definitions of such costs on the invoice.[107] Indeed, the description EEI provides on its invoices is by no means a comprehensive breakout of how the organization spends the funds it receives from member utilities such as Kentucky Power.

EEI is an electric utility lobbying organization, whose primary interest is the protection of utility shareholders.[108] Well-established Commission precedent disallows 45.35% of dues paid to EEI because that portion of the dues provides funding for EEI legislative advocacy, regulatory advocacy, and public relations.[109] The Commission established this precedent because none of those three activities provide a *direct* benefit to customers in *any* way, shape or manner.[110] Multiple Commission orders have relied upon a designation of such activities as determined by NARUC operating expense categories,[111] and placed on former EEI invoices. The fact that these Commission precedents predate the current case by more than thirty years does not in any manner change the vital need to protect customers from being forced to provide funding for industry lobbying activities.

Of the $88,164 in EEI dues for which Kentucky Power is responsible in the instant case, the Company excluded only $16,445.[112] Therefore, the Commission should reduce the $0.088 million in EEI dues included in the test year by 45.35% in accordance with clear Commission precedent.[113] This is a higher percentage of costs than designated on the invoice itself, because there is *no evidence* that EEI's characterization of "influencing legislation"[114] includes the sums it spends on the *additional* Commission-disapproved lobbying activities of regulatory advocacy and public relations. Moreover, Kentucky Power's Response to the Commission Staff's Post-Hearing Data Request, Item No. 2, includes a litany of

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[107] Kollen Testimony at 37:17-38:1.
[108] Kollen Testimony at 37:2-3.
[109] *See* AG-KIUC Response to Staff's Data Requests, Item No. 13 and multiple attachments thereto.
[110] *See, e.g., In Re*: *Adjustment of Gas and Electric Rates of Louisville Gas & Electric Co.,* Case No. 10064, Order (July 1, 1988) at 58-60.
[111] Case No. 2003-00433, Order (June 30, 2004) at 51-52; Case No. 2003-00434, Order (June 30, 2004) at 44-45. *See also* AG-KIUC Response to Staff's Data Requests, Item No. 13.
[112] West Rebuttal at 16, Fig. 2.
[113] See Mr. Kollen's response to Staff's Data Requests to the AG-KIUC, item no. 13; and West Rebuttal at 16, Fig. 2.
[114] Kentucky Power Response to AG-KIUC Item No. 2-44, Attachment 1 at 3.

activities EEI engages in, yet notably fails to include any description of the regulatory advocacy and public relations activities in which EEI engages. Removing 45.35% of Kentucky Power's $88,164 share of EEI dues yields a figure of $40,000 that must be excluded from the base revenue requirement.

VI. COST OF CAPITAL ISSUES

A. The Commission Should Reject Kentucky Power's Preferential Allocation Of The Mitchell Coal Stock Pro Forma Adjustment.

Kentucky Power made a pro forma adjustment to capitalization of $13.084 million to reduce actual Mitchell coal inventories to target levels ("Mitchell Coal Stock Adjustment"), but allocated this adjustment first to short-term debt until it was reduced to $0 and then allocated the remainder between long-term debt and common equity.[115] This allocation of the Mitchell coal stock pro forma adjustment first to short-term debt was unreasonable.[116]

The Company does not finance long-term coal inventories solely with short-term debt, and any disallowance of the Mitchell coal inventories should not be preferentially assumed to be financed with low-cost, short-term debt with only minimal long-term debt or common equity. If there had been sufficient short-term debt, the Company would have allocated the entirety of the adjustment to short-term debt and none of it to long-term debt or common equity. This fact alone demonstrates the fallacy of the Company's approach because it rests not on any principle, but only on the amount of short-term debt outstanding at the end of the test year. If the test year had ended December 31, 2019, then the Company would have allocated the entirety of the adjustment to short-term debt simply because there was sufficient short-term debt for it to do, and not because it actually financed the excessive coal inventory at Mitchell with short-term debt.[117]

[115] Section V, Exhibit 1, Workpaper S-3 at 1 and 4.
[116] Kollen Testimony at 39:4-6.
[117] Kollen Testimony at 39:4-17.

Accordingly, the Commission should require Kentucky Power to allocate the Mitchell Coal Stock Adjustment proportionately across the capital structure, rather than preferentially allocating it first to short-term debt on the base revenue requirement. The effect is a reduction of $0.705 million in the base revenue requirement.[118]

B. The Commission Should Reject Kentucky Power's Proposed Capital Structure.

Kentucky Power proposes an unreasonable capital structure consisting of 0% short-term debt, 3.02% accounts receivables financing, 53.73% long-term debt, and 43.25% common equity. This structure reflects no short-term debt due to the Mitchell Coal Stock Adjustment despite the fact that the Company has a long history of using significant amounts of low-cost short-term debt to finance its utility and other investments. More specifically, the Company had an average monthly balance of short-term debt outstanding of $80.621 million in the test year.[119] In fact, it had a balance of short-term debt of $113.175 million at December 31, 2019 (6.42% of its capital structure) and increased that amount to $120.549 million at February 28, 2020.[120] Just before the end of the test year, Kentucky Power paid down this short-term debt to $10.536 million at March 31, 2020, or 0.595% of its capital structure, and then subsequently pro formed this amount to $0 for ratemaking purposes.[121]

A reasonable amount of short-term debt to include in the "per book" capital structure before pro forma adjustments and before allocations to Kentucky retail jurisdiction is the amount that the Company itself deemed reasonable and borrowed on average during the test year - $80.621 million.[122] And a reasonable interest rate on this short-term debt is 0.51% - the most recent interest rate on short-term debt incurred by the Company.[123] Adopting this approach would not change the total debt and common equity

[118] Kollen Testimony at 39:19-40:1.
[119] Section V, Schedule 3 Workpaper S-3 at 3, line 14.
[120] Exhibit LK-17; Kentucky Power Response to Staff Item No. 2-2, Attachment 1; Section V, Schedule 3, Workpaper S-3 at 3, line 11.
[121] Exhibit LK-17; Kentucky Power Response to Staff Item No. 2-2, Attachment 1; Kollen Testimony at 40:9-19.
[122] Kollen Testimony at 41:1-5.
[123] Kollen Testimony at 41:12-13; Exhibit LK-18 Kentucky Power Response to AG-KIUC Item No. 1-75.

capitalization proposed by Kentucky Power. It would only modify the debt component to reflect the additional short-term debt in lieu of a comparable amount and percentage of long-term debt.[124] Including the test year monthly average of short-term debt in the capital structure on the base revenue requirement would reduce the base revenue requirement by $2.512 million.[125]

C. The Commission Should Not Reflect Kentucky Power's Maturing 7.25% Long-Term Debt In The Base Revenue Requirement.

Kentucky Power has an outstanding $40 million in Senior Unsecured Notes – Series A that will mature on June 18, 2021 - less than six months after rates are reset in this proceeding.[126] The effective interest rate on this debt issue is 7.319%, which includes the interest on the principal plus the amortization of discount and issuance costs. The annualized cost of this debt issue is $2.928 million (total Company).[127]

Kentucky Power's practice has been to issue new debt to replace debt when it matures.[128] And the cost of the new debt will be substantially less than the effective 7.319% cost on the maturing debt. Interest rates are at historic lows, due in part to the federal government and the Federal Reserve's responses to the Covid-19 pandemic. 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. The effective interest rate typically increases with the length of the tenor. The effective interest rates on the Company's four separate debt issuances with different tenors issued on September 12, 2017 demonstrate this correlation. The seven-year tenor has an effective interest rate of 3.182%, the ten-year tenor has an effective interest rate of 3.388%, the twelve-year tenor has an effective interest rate of 3.483%, and the thirty-year tenor has an effective interest rate of 4.139%. Interest rates have declined since September 2017.[129]

[124] Kollen Testimony at 41:1-10.
[125] Kollen Testimony at 41:15-18.
[126] Exhibit LK-19; Kentucky Power Response to Staff Item No. 2-3, Attachment 1 at 2.
[127] Kollen Testimony at 42:1-5.
[128] Kollen Testimony at 42:7-8.
[129] Kollen Testimony at 42:10-43:2.

Due to the short period remaining (less than six months after rates are reset in this proceeding) during which this high-cost debt issue will remain outstanding, this cost should not be included in the base revenue requirement. Instead, the Commission should reflect a 4.0% cost for the new debt issue in the weighted cost of long-term debt and direct the Company to defer the difference in jurisdictional interest expense between this rate and the high-cost debt issue 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. At that time, the regulatory asset will be included in rates, and the Company will recover the deferred interest expense or repay the recovery in excess of the interest expense if there is either a regulatory asset or a regulatory liability at that date.[130]

The annualized reduction in annual interest expense when the high-cost issue is replaced with new lower-cost debt in June 2021 will be $1.3 million or more (total Company). In other words, by January 1, 2024 - three years from the date rates will be reset in this proceeding – Kentucky Power will have recovered approximately $3.3 million more than its actual interest expense after June 18, 2021 if the Commission does not act to protect customers in this proceeding.[131]

This recommendation will not harm Kentucky Power. It is fair to both the Company and its customers. Kentucky Power recovers its actual interest expense and the customers pay the Company only its actual interest expense. This recommendation to reduce revenue requirements through a known and measurable reduction to test year expenses is similar to the Company's proposed post-test year increase to revenue requirements related to the Rockport UPA demand expense increase. The effect is a reduction of $0.793 million in the base revenue requirement.[132]

[130] Kollen Testimony at 43:4-16.
[131] Kollen Testimony at 43:18-44:2.
[132] Kollen Testimony at 44:4-13.

D. The Commission Should Set Kentucky Power's After-Tax Return On Equity At 9.0%.

Kentucky Power's requested after-tax ROE of 10.0% is too high and fails to appropriately balance the impact on customers with a fair return to investors. A 10.0% after-tax ROE would inflate the Company's revenue requirement and contribute to an unnecessary additional rate increase for Kentucky customers, again exacerbating financial pressures in a service territory with diminishing load.[133] Compared to the AG-KIUC recommended after-tax ROE of 9.0% discussed below, an after-tax ROE of 10.0% would increase the revenue requirement by $8.33 million per year based on the Company's requested capital structure and rate base. This would be particularly harmful to customers in the current, difficult economic environment. Customers should support a fair rate of return to the Company, but they should not be burdened with excessive costs from an inflated after-tax 10.0% ROE.[134]

Kentucky Power witness McKenzie's assertion that an after-tax ROE of up to 10.3% would be reasonable significantly overstates the current investor-required return for the Company. As AG-KIUC witness Baudino explained, today's financial environment of low interest rates has been deliberately and methodically supported by Federal Reserve policy actions since 2009. An after-tax 10.3% ROE is inconsistent with investor-required returns for low-risk regulated utilities like Kentucky Power.[135]

A reasonable after-tax ROE range for Kentucky Power in this proceeding is 8.93% - 9.25%.[136] This range is supported by AG-KIUC witness Baudino's Discounted Cash Flow ("DCF") and Capital Asset Pricing Model ("CAPM") analyses, the results of which are set forth in the table below.[137]

[133] Stenographic Tr. (November 17, 2020) at 72:7-13 ("…And, Mr. Mattison, you understand, and I think you reflected in your testimony, that as rate base continues to shrink in our territory, that fewer customers are going to be asked to pay more simply because there are fewer available to pay your cost; is that correct?" Company witness Mattison: "That would be correct.").
[134] Baudino Testimony at 4:9-20.
[135] Direct Testimony of Richard A. Baudino ("Baudino Testimony") at 4:2-7 and 37:4-10.
[136] Baudino Testimony at 3:2-13.
[137] Baudino Testimony at 3:21-24; Baudino Testimony at 35:1.

TABLE 3
SUMMARY OF ROE ESTIMATES

DCF Methodology	
Average Growth Rates	
- High	9.05%
- Low	8.75%
- Average	8.93%
Median Growth Rates:	
- High	9.63%
- Low	8.61%
- Average	9.25%
CAPM Methodology	
Forward-lookng Market Return:	
- Current 30-Year Treasury	9.80%
- D&P Normalized Risk-free Rate	9.95%
Historical Risk Premium:	
- Current 30-Year Treasury	6.73% - 7.65%
- D&P Normalized Risk-free Rate	7.85% - 8.77%

Within this range of reasonableness, AG-KIUC recommend an after-tax ROE of 9.0%. A 9.0% ROE represents a reduction of 25 basis points from the upper level of the range recommended by Mr. Baudino, approximately the same reduction proposed by the Company itself.[138] Further, many of the same policy factors that Kentucky Power cites when explaining its choice to seek a 10.0% ROE rather than a 10.3% ROE support AG-KIUC's ROE recommendation.[139] As Kentucky Power witness Mattison states:

> Company Witness McKenzie's analysis demonstrates that an ROE of 10.3% is warranted for the Company. Although Mr. McKenzie's analysis supports a higher ROE, Kentucky Power is requesting an ROE of 10.0% as a third way to mitigate the rate increase in this case. Each of these measures represents a one-time proposal that Kentucky Power is making, without prejudice to the Company's positions in future rate cases, in recognition of the unique economic and financial challenges that customers in the Company's service territory are facing as a result of COVID-19.[140]

In addition to the economic and financial challenges that customers are currently facing, setting ROE at or near the lower end of the range determined reasonable would be consistent with the Commission's Order in Case No. 2017-00179, wherein it stated:

[138] Kollen Testimony at 45:10-12.
[139] Kollen Testimony at 44:18-24.
[140] Direct Testimony of D. Brett Mattison at 8.

> The Commission is cognizant of the risk inherent to Kentucky Power's service territory and load profile. The Commission notes the Attorney General's position that Eastern Kentucky has been economically depressed for the past decade and that the Commission should consider the economic conditions of the region in evaluating the overall rates and rate design. Therefore, given the adverse economic situation of the service territory of high unemployment, low earnings, and high poverty rates, the Commission finds a lower ROE will allow Kentucky Power to earn a fair return while reflecting the situation of its customers.[141]

And since the Commission issued its Order in the last case, economic conditions in Eastern Kentucky have deteriorated further.[142]

Adoption of a 9.0% after-tax ROE is fair to Kentucky Power. The Company will be guaranteed its authorized return in the base revenue requirement in 2023 pursuant to the settlement term approved by the Commission in Case No. 2017-00179. Under that settlement term, the Company will use the $57.4 fixed cost reduction in the Rockport UPA revenue requirement in 2023 to recover any earnings deficiency calculated on a per books basis in 2023. After the Company meets its authorized return, the remainder will flow through to customers in the PPA rider.[143]

Further, the ROE established in this proceeding will be applied in the Company's riders that include rate base amounts, including the ES, Decommissioning Rider, and the PPA rider (return on deferral of Rockport UPA costs through December 7, 2022 and current return thereafter). These riders all provide the Company guaranteed recovery of approved costs and thus, have less regulatory and financial risk than the costs recovered through base rates.[144]

The effect of adopting AG-KIUC's ROE recommendation is a reduction of $7.576 million in the base revenue requirement.[145] This reduction is incremental to the other cost of capital reductions discussed above. The effects of the AG-KIUC cost of capital recommendations, including the 9.0% after-tax ROE,

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[141] Case No. 2017-00179, Order (January 18, 2018) at 29.
[142] Kollen Testimony at 46:13-14.
[143] Kollen Testimony and Corrected Pages to Kollen Testimony at 45:13-19.
[144] Kollen Testimony at 45:20-25.
[145] Kollen Testimony at 44:12-13.

will also reduce the ES revenue requirement by $3.420 million in the ES revenue requirement and will reduce the Decommissioning Rider revenue requirement by $1.267 million.[146]

The authorized rate of return established by a state regulator sends a message to Wall Street. A high return signals that the Commission is pleased with the direction of the utility and its parent company.

E. The Commission Should Extend The Rockport 2 SCR Depreciation Expense In The Environmental Surcharge To Reflect A Ten-Year Amortization Period.

Kentucky Power's extreme proposal in its direct case to recover its $40.6 million share of the Rockport 2 selective catalytic recovery ("SCR") system for NOX reduction through the ES over three years merely because the Rockport contract extends for three years was only slightly revised in rebuttal to four years.[147] Both proposals should be rejected.[148] Recovering the Rockport 2 SCR over ten years will much more closely track its actual service life, will lower the initial rate shock on customers, and through the use of deferral accounting, will not adversely affect the Company's earnings (even though cash flow will be reduced). This is a $15.953 million issue.

AEP Generating Company ("AEGCo") chose to incur $135.373 million to install a new SCR on Rockport Unit 2 in 2020 despite the fact that AEGCo's Rockport 2 lease and the Rockport UPA both terminate on December 7, 2022. Although the Commission cannot force AEGCo to reverse this decision, the Commission can protect Kentucky Power's customers from paying the unreasonably high rates that would result from recovering the Company's share of the SCR costs over only four years.

Contrary to Kentucky Power's insinuations, the KRS 278.183 requirement for the "current recovery" of "reasonable operating expenses" including "depreciation" does not mandate four-year cost recovery for the SCR. With respect to capital assets that are part of an approved environmental compliance

[146] Kollen Testimony at 46:21-28.
[147] Rebuttal Testimony of Alex E. Vaughn at 8.
[148] Kollen Testimony at 50:13-17.

plan, the term "current" within the statute simply authorizes the recovery of a return on CWIP once construction begins, not current recovery of the CWIP as it is incurred. After the project goes into commercial operation, the recovery of depreciation starts. The Commission's typical practice under the ES is to allow utilities to recover the depreciation costs of a given environmental compliance asset over the useful life of that asset. The useful life of the SCR is far longer than four years. Even though the Rockport 2 SCR has a useful life of 20 to 30 years, the AG-KIUC recommendation is to adopt a ten-year depreciation/amortization period.

The Indiana Utility Regulatory Commission ("IURC") recently addressed the Rockport 2 SCR depreciation issue. In IURC Cause No. 44871, I&M proposed and the IURC authorized a ten-year depreciation period.[149] That is the same ten-year period proposed by the AG and KIUC here. It is not clear why AEP proposed ten years in Indiana and only four in Kentucky. It is the same piece of equipment.

This Commission can and should modify the recovery of the SCR depreciation expense in the ES to reflect an extended depreciation/amortization period. It should direct Kentucky Power to defer the difference in the depreciation expense from January 2021 through December 7, 2022 and begin to amortize the deferral starting December 8, 2022 through the end of the amortization period.[150] This recommendation is revenue-neutral to the Company and is an easy way to mitigate the impact of the proposed rate increase on Kentucky Power's customers. Because of the functioning of the ES, the Company will receive its weighted average cost of capital carrying charge on the unamortized balance. The effect is a $15.953 million reduction in the ES revenue requirement.[151]

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[149] Kollen Testimony at 51:7-16.
[150] Kollen Testimony at 50:19-51:5.
[151] Kollen Testimony at 51:18-52:2.

F. The Commission Should Deny Recovery Of Incremental OATT LSE Net Expenses Through The PPA Rider And Should Instead Revert To Full Base Rate Recovery.

The Company seeks to recover 100% of incremental increases in the OATT LSE net expenses incurred after the test year (which reflect a 10.35% FERC-approved ROE and 55% equity capitalization for the transcos) through the PPA Rider.[152] This is unreasonable. Consistent with the Commission's practice for years prior to the Company's last rate case, all of Kentucky Power's transmission costs should be recovered through base rates. Base rate recovery is in full compliance with all legal requirements and will give Kentucky Power an incentive to manage and reduce its transmission costs, as well as the transmission costs allocated to it under the AEP Transmission Agreement.

The primary driver of increases in Kentucky Power's OATT LSE net expenses is transmission capital expenditures by other AEP utilities and AEP state transmission companies ("transcos") in Ohio, Indiana, Michigan, Virginia, West Virginia and Tennessee, not in Kentucky. This is how the AEP Transmission Agreement works. All PJM transmission revenues and expenses run thorough AEPSC. Each transmission owner (including Kentucky Power) is paid by AEPSC for its revenue requirement based on its individual transmission investment. But as a transmission user, or Load Serving Entity ("LSE"), each utility (including Kentucky Power) is allocated its 12 CP share of all transmission costs throughout the AEP East zone. Under this system, there are winners and losers. Because of explosive transmission spending in other states, Kentucky loses. And that loss grows each year.

More than 90 percent of the base amount of PJM LSE OATT expenses in Kentucky Power's test year are affiliate expenses.[153] Additionally, as shown in AG-KIUC witness Baron's updated Table 3, the annual growth rate in transmission revenue requirement from 2017-2021 was only 2.75% in Kentucky

[152] Stenographic Tr. (November 17, 2020) at 59:14-22 and 60:18-25.
[153] Stenographic Tr. (November 17, 2020) at 199:25-200:7.

compared to annual growth rates of 11.47% in West Virginia/Virginia/Tennessee, 15.19% in Indiana/Michigan, and 10.47% in Ohio over the same period.

Kentucky Power's allocated share of AEP transmission costs has significantly increased in recent years, and that increase is projected to continue. From Kentucky Power's 2014 rate case (Case No. 2014-00396) to the current case, the Company's allocated share of AEP net PJM LSE OATT charges and credits has increased by 80% (from $53.8 million to $96.9 million).

In 2021, the difference in total revenue requirements between Kentucky Power's actual transmission costs (including the Kentucky transco) on a standalone basis and the amount allocated to it under the AEP Transmission Agreement will be $27.689 million. That $27.689 million is about 25% above Kentucky Power's standalone transmission costs.

In other words, customers in the severely depressed eastern Kentucky region are subsidizing customers from Michigan to Virginia. Authorizing the automatic recovery of this subsidy through the PPA rider is absolutely the wrong policy as it provides no incentive for Kentucky Power to control these costs. Because of the federal nature of the AEP Transmission Agreement, the Commission's options are limited. But requiring base rate recovery is absolutely within the Commission's jurisdiction and is necessary. Allowing PPA rider recovery means an automatic rate increase of $14 million beginning January 1, 2021.[154]

If the Commission reverts to its prior practice of providing full recovery of the FERC-approved transmission expenses through base rates, then it will have fulfilled its obligation to provide recovery consistent with federal and state law. Until the last rate case, Kentucky Power was not authorized to recover any post-test year increases in these expenses through the PPA rider. Thus, terminating rider recovery of such expenses when base rates are reset in this proceeding simply represents a reversion to

[154] Rebuttal Testimony of Alex E. Vaughn at 15.

the same recovery process as existed for decades.[155] If recovery of Kentucky Power's incremental OATT LSE net expenses through base rates creates earnings erosion between rate cases, then the Company should address this issue with its affiliate utilities and affiliate state transcos. This is not a problem created by customers and should not be resolved by imposing automatic increases on customers through the PPA rider between base rate proceedings.[156]

G. The Commission Should Terminate the Capacity Charge Tariff Regardless Of Any Change To The Requested Base Rate Increase.

As part of a 2004 Commission-approved Settlement Agreement between Kentucky Power, the AG, and KIUC that included an 18-year extension of the Rockport UPA until December 7, 2022, Kentucky Power was permitted to recover a premium over and above cost of service for Rockport. For the first five years of the 18-year extension, Kentucky Power recovered a $5.1 million premium per year and for the next 13 years, Kentucky Power was to recover a $6.2 premium per year.[157] Hence, under present circumstances, Kentucky Power will continue to recover the $6.2 million premium annually through the CC tariff through December 7, 2022 when the Rockport 2 lease is terminated and the Rockport UPA is terminated. Over the entire 18 year extension, the premium would be $106 million (nominal) and $173 million (NPV at an 8% carrying charge).

In this case, however, Kentucky Power puts that portion of the Settlement Agreement in play again, proposing to terminate the CC tariff effective when base rates are reset in this proceeding subject to the condition that the Commission make no changes to its requested base rate increase.[158] But the Commission could terminate the CC tariff when base rates are reset in this proceeding regardless of

[155] Kollen Testimony at 53:1-9.
[156] Kollen Testimony at 54:14-20.
[157] Kollen Testimony at 55:20-56:5.
[158] Application at 8, P. 13(a).

Kentucky Power's condition. The CC tariff is a retail rate and is not a cost imposed on the Company through a FERC tariff, unlike the costs imposed pursuant to the Rockport UPA itself.

The Commission adopted the CC tariff through a Settlement Agreement as an incentive to renew the Rockport UPA for an additional 18 years. But the Commission has an ongoing statutory obligation to ensure the rates remain just and reasonable. As it recently explained:

> The Commission's statutory obligation when reviewing a rate application is to determine whether the proposed rates are "fair, just, and reasonable." Even though [the utility] and the Attorney General have filed a Joint Stipulation that purports to resolve all of the issues in the pending application, the Commission cannot defer to the parties as to what constitutes fair, just, and reasonable rates. The Commission must review the record in its entirety, including the Joint Stipulation, and apply its expertise to make an independent decision as to the level of rates, including terms and conditions of service, that should be approved.[159]

Since 2004, circumstances have changed significantly and the CC tariff is no longer reasonable.[160] First, the 12.16% ROE that Kentucky Power pays AEGCo for AEGCo's investment in the Rockport plant is excessive under current market conditions. And that very high ROE is being applied to a smaller rate base as the Rockport plant is depreciated. When the $6.2 million of "free" money recovered through the CC tariff is added to AEGCo's contractual 12.16% equity return recovered through base rates and the ES, then AEP's realized return is much greater than 12.16%. For the period August 2019 through July 2020, when the $6.2 million CC revenue is added to the FERC-approved 12.16% ROE, AEP earned an effective ROE of 33.81% on its Rockport investment.[161]

Second, the litigation between AEP and EPA surrounding environmental compliance throughout the entire AEP East System has forced Kentucky Power customers to pay for significant new capital investments at Rockport through the environmental surcharge over a short period of time. As discussed above, Kentucky Power's cost of the Unit 2 SCR is $40.6 million. And the capital cost of the recent

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[159] *In the Matter of Electronic Application of Duke Energy Kentucky, Inc. to Amend Its Demand Side Management Programs*, Case NO. 2019-00277 (April 27, 2020) at 13-14.
[160] Kollen Testimony at 57:10-17.
[161] Kollen Testimony at 57:18-58:3.

enhanced Dry Sorbent Injection on Unit 2 will only increase the operating costs of both Rockport Units. These environmental costs paid for by customers through the ES may have been necessary to meet the requirements of an EPA Consent Decree, but they also reduced AEP's litigation risk.[162]

Finally, load growth, or the lack thereof, has changed. Kentucky Power places great emphasis on its weather-normalized sales decline of 23.4% from 2008-2019, and AG-KIUC agree that is important.[163] Updated with the 2020 sales decline of (-6.4%) and the 2021 sales decline of (-1.6%), the 2008-2021 weather-normalized sales reduction will be (-31.4%).[164] In contrast, when the 18-year Rockport UPA extension was approved in 2004, sales for Kentucky Power were projected to increase in the range of 1.1%-1.6% annually.[165] In today's environment, only the cost-based Rockport UPA should be recovered in rates, but no premium.

Paying a premium over and above cost-of-service for 16 years has been long enough. The CC tariff should be terminated two years early when new rates take effect in this case. The CC currently costs the average residential customer $1.66 per month. If the CC premium continues from the effective date of new rates in this case until December 7, 2022, then the average residential customer will pay an additional $38.[166] Asking residential customers to continue paying a premium of $1.66 per month under current economic conditions is unreasonable. Nor should residential and business customers pay AEP an effective ROE of 33.81% on its Rockport investment.[167]

The 2004 Rockport Settlement contemplated that recovery of the premium might be cut short by the Commission, and the Settlement provided Kentucky Power a remedy. Its remedy is to terminate the

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[162] Kollen Testimony at 58:4-15.
[163] Kentucky Power Post-Hearing Brief at 5.
[164] AG-KIUC Hearing Exhibit 1 at 79.
[165] Staff Report on the 2009 Integrated Resource Plan of Kentucky Power Company, Case No. 2009-00339 at 16 "The 1999 forecast projected total internal energy requirements for Kentucky Power of 9,688 GWH in 2016 and an average annual growth rate of 1.6%. The 2009 forecast projects total internal energy requirements of 8,596 GWH for 2016 and an average annual growth rate of only 1.1%."
[166] Kollen Testimony at 56:6-8.
[167] Kollen Testimony at 58:16-21.

18-year UPA extension.[168] In the unlikely event that the Company would exercise that right, then customers would benefit greatly through the early termination of the UPA and the receipt of $57.4 million in annual Rockport fixed cost savings.

H. The Commission Should Reject the Company's Proposed Grid Modernization Rider.

Kentucky Power proposes a new GMR "to recover the capital and incremental operation and maintenance expenses associated with projects to modernize the distribution grid or to improve the Company's reliability and resiliency, including the Company's AMI deployment proposed in this case."[169]

The Commission should reject the proposed GMR. First, there is no need for the proposed GMR to recover the costs of AMI meters and the related infrastructure if the Commission denies a CPCN. Second, there is no evident or compelling need for the GMR to provide recovery of unknown future distribution modernization projects. Third, the costs of new distribution investments historically have not been carved out for special ratemaking recovery through riders between base rate proceedings. This also has been true for gas utilities, except where it was necessary to incur significant costs to accelerate the replacement of pipelines and services assets due to safety issues. Fourth, Kentucky Power has not demonstrated any special financial or other need to recover incremental distribution costs through a rider rather than base rates when they are periodically reset.[170] Fifth, Kentucky Power has proposed no offsets to the incremental costs recoverable through the proposed GMR for the decrements in costs that will occur when new distribution assets are placed in service, such as the proposed AMI and related infrastructure.[171] In the case of the AMI and related infrastructure, there will be some savings that should be offset against

[168] Case 2004-00420 Settlement Agreement at Section VI.3. "If at any time prior to the expiration of the extension of the UPSA under this Stipulation and Settlement Agreement the Kentucky PSC or its successor enters an Order that prevent Kentucky Power from charging rates consistent with the provisions of …this Stipulation and Settlement Agreement Kentucky Power may…begin legal or regulatory proceedings necessary to terminate the extension of the UPSA and withdraw from all obligations under this Agreement."

[169] Application at 10, P 18(a).

[170] Kollen Testimony at 59:1-21.

[171] Exhibit LK-21; Kentucky Power Response to AG-KIUC Item No. 1-90. The Company provided its estimate of incremental O&M expense. There were no decrements or offsets for savings.

the costs of the new investments and operating expenses. The Company will achieve maintenance expense savings due to lower failure rates and due to the ability to remotely turn on and turn off service.[172] Also in that case, 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 GAAP and the FERC USOA.[173] Additionally, in that case, Kentucky Power will no longer incur ad valorem tax expense on the retired AMR meters and related infrastructure.[174] Finally, Kentucky Power has proposed no offsets for the reductions in rate base on existing distribution investments to reflect increases in accumulated depreciation and ADIT, which are sources of funds for new investment between base rate proceedings.[175]

If the Commission ultimately approves a GMR, then it should at minimum, modify the costs recovered through the proposed rider to reflect all savings in O&M expense, depreciation expense, ad valorem tax expense, and other expenses as reductions in the GMR revenue requirement. The Commission should also modify the proposed rider to reflect the decrements in costs on existing distribution plant due to increases in accumulated depreciation and ADIT.[176]

I. The Commission Should Reject The Proposed CPCN For AMI Meters and Infrastructure.

Kentucky Power requests a CPCN to replace its existing AMR meters and related infrastructure with new AMI meters and related infrastructure over the four-year period 2021-2025. The Company plans to spend $36.960 million over those four years, consisting of $34.494 million in capital expenditures and $2.466 million in O&M expense.[177] Kentucky Power's proposed AMI and related infrastructure is a

[172] Direct Testimony of Stephen Blankenship at 13 ("the Company expects the transition to AMI meters to result in a reduction in fleet costs and other savings from streamlining of departments."). The Company provided estimated savings in Account 902 Meter Reading of $0.623 million.
[173] Exhibit LK-22; Kentucky Power Response to AG-KIUC Item No. 1-63. The Company provided estimated reduction in AMR meter depreciation expense of $0.889 million.
[174] Kollen Testimony at 59:22-60:11.
[175] Kollen Testimony at 60:12-15.
[176] Kollen Testimony at 60:18-61:5.
[177] Direct Testimony of Stephen Blankenship at 17.

significant cost and it is *discretionary*. It will impose an unnecessary cost on its customers in a difficult economic environment - a fact that the Company has acknowledged.[178]

Critically, Kentucky Power has not performed a cost/benefit study to justify the replacement of its AMR meters and related infrastructure. The Company simply claims that an economic study is not necessary, would provide "only limited utility,"[179] and that it has no intention to perform one.[180] These claims are suspect. In lieu of a comprehensive cost-benefit study, the Company has submitted only vague, unverifiable information bereft of empirical data, instead submitting mere generalized studies illustrating categories of savings that customers might realize, and even satisfaction surveys.[181] Moreover, the value of any such benefits is made even more illusive in the Company's acknowledgement that many benefits have already been achieved in its current AMR metering system.[182] Indeed, it appears that rather than following the Commission's guidance that utilities should *maximize* benefits that AMI technology can bring,[183] Kentucky Power has gone out of its way to *minimize* them.

Furthermore, the Application fails to identify the types and models of AMI infrastructure Kentucky Power would deploy. Instead, the Company bases its claims of ratepayer benefits upon AMI infrastructure deployed in *affiliates'* service territories, thus making it impossible to determine whether any savings *at all* could be achieved. The Commission should not grant a multi-million dollar CPCN based on alleged data not of record in the instant proceeding purportedly derived from infrastructure deployed in foreign jurisdictions.

Additionally, while the Company asserts that its current metering system is "technologically obsole[te]," nonetheless it acknowledges that it has available supplies of retired, but still functional, AMR

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[178] Kollen Testimony at 62:1-5.
[179] Response to AG-KIUC DR 1-89.
[180] Exhibit LK-23; Kentucky Power Response to AG-KIUC Item No. 1-95.
[181] Blankenship direct testimony at 9:14.
[182] Blankenship rebuttal 6:11-14: ". . . 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."
[183] *In Re*: Electronic Application Of Duke Energy Kentucky, Inc. To Amend Its Demand Side Management Programs, Case No. 2019-00277, Final Order issued April 27, 2020, at 14-15.

meters from its sister utilities that it can use to replace AMR meters or components, such as communication modules, if and when the meters or components fail.[184]Additionally, at least one vendor continues to manufacture the type of meter it currently uses.[185] There is thus no reason to conclude that the existing AMR system is about to fall apart. It can continue operating at least until such time as the Company is able to file a more reasoned application founded upon a thorough cost-benefit analysis, and which identifies and guarantees all savings customers will experience.

Accordingly, the Commission should deny the requested CPCN without prejudice. The proposed retirement of AMR meters and infrastructure with AMI meters and infrastructure is not necessary at this time, nor is it economic. Since Kentucky Power has refused to submit any cost-benefit analyses with the current application, there is no way for the Commission to determine whether the cited "benefits" of the proposed AMI meters are accurate in any manner. Most importantly, this is not the right time to impose discretionary costs on a declining customer base that is suffering economically.[186] The Commission should also require that if and when the Company re-files its petition for a CPCN for AMI, that it also: (i) conduct a thorough cost-benefit analysis identifying all potential savings AMI could bring, together with a net present value analysis; and (ii) ensure that customers will actually receive the slated benefits, through transparent and verifiable accounting measures.

J. The Commission Should Use Unprotected Excess ADIT To Offset Both 100% Of The First Year And 50% of the Second Year Of the Allowed Requested Base Rate Increase.

Kentucky Power's proposal to use excess unprotected ADIT – money that it owes to customers for prior tax overcollections - to mitigate the effects of the allowed net rate increase is reasonable. It accelerates the refund already due to customers in order to provide much-needed relief.[187] However, given the current financial needs of customers within Kentucky Power's service territory, as well as the size of

[184] Exhibit LK-24; Kentucky Power Response to AG-KIUC Item No. 1-117; and Blankenship Direct at 4:22 – 5:2.
[185] Direct Testimony of Stephen Blankenship at 3-4.
[186] Kollen Testimony at 62:19-63:5.
[187] Kollen Testimony at 47:19-48:2.

the rate increase requested by the Company, the Commission should not limit the EDIT offset to the first year of the proposed rate increase. Rather, the Commission should use an additional amount of the EDIT remaining at the end of 2021 to mitigate 50% of the net increase that otherwise will occur in 2022. This will provide additional mitigation using the customers' own funds and phase-in the net rate increase to its full level in 2023.

Beginning on December 8, 2022, there will be $57.4 million in annual Rockport fixed costs savings available for further rate mitigation, and as approved in the last rate case to bring the Company's ROE up to its authorized level for calendar year 2023. This 2023 ROE make whole provision is a significant benefit to the Company that should be factored into the rate calculus of this case.

Sufficient EDIT exists to support this additional mitigation in 2022. Kentucky Power had a revenue equivalent of $113.5 million in EDIT at April 30, 2020.[188] The Company also continues to amortize the EDIT through the FTC Tariff. This will have a revenue equivalent remaining balance of approximately $96-$107 million at the end of this year, depending on whether the Commission uses a portion of the balance to relieve outstanding uncollectible accounts.[189] Accordingly, it is reasonable to provide Kentucky Power's residential and business customers the benefits of the money owed to them sooner rather than later.

AG-KIUC also support Kentucky Power's proposal to continue the test year level of the FTC Tariff until the EDIT is fully utilized. Because the EDIT constitutes funds that are owed to customers, giving those funds back to customers in the amounts contained in the current FTC Tariff is reasonable. Reducing the FTC Tariff would effectively be a rate increase, which should be avoided.[190]

Finally, the AG and KIUC support using $10.8 million of EDIT to eliminate all customer balances

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[188] Direct Testimony of Brian West at 8.
[189] Kollen Testimony at 49:1-10.
[190] Kollen Testimony at 49:12-17.

that were more than 30 days past due as of May 28, 2020 as specified in Case No. 2020-00176. It will be a welcome relief for thousands of families and businesses to learn that their bad debt is forgiven. But we must point out that Kentucky Power will also benefit. The $10.8 million will go directly to it.

K. The Commission Should Adopt Kentucky Power's Proposed Cost Allocation.

Kentucky Power developed a class cost of service study for the test year ending March 31, 2020 using a traditional 12 coincident peak methodology ("12 CP") to allocate production and transmission costs to rate classes. While alternative methodologies for production cost allocation that focus more extensively on the summer system peak, which drives the need for capacity on the Kentucky Power system, could be considered, the 12 CP study filed by the Company is appropriate in this case to assess the reasonableness of class rates, relative to the cost of providing service.[191]

Kentucky Power's cost of service study shows that there is a significant amount of cross-subsidization between rate classes. Table 1 below summarizes the current rate of return at present rates, the relative rate of return and the dollar subsidies paid or received by each rate class at present rates.[192]

[191] Direct Testimony of Stephen J. Baron ("Baron Testimony") at 5:3-14.
[192] Baron Testimony at 8:4-10.

Table 1
Class Cost of Service Results - Present Rates

Class	Rate of Return %	Relative ROR Index	Current Subsidy*
RS	-0.11	-0.04	31,803,815
GS	7.25	2.53	(11,162,192)
LGS	6.38	2.23	(7,185,639)
IGS	5.62	1.97	(9,447,749)
MW	9.51	3.33	(35,229)
OL	15.21	5.32	(3,396,449)
SL	17.35	6.07	(576,557)
Total	2.86	1.00	0

* Positive value indicates that a subsidy is being received;
negative value indicates subsidy is being paid.

All of the non-residential rate classes are paying subsidies to the residential class. For instance, Rate IGS, which serves large industrial manufacturing customers, is paying $9.4 million in subsidies. This means that these industrial customers are paying over $9.4 million a year more in electric power rates than KPCo's cost to actually provide the power.[193]

In the last Kentucky Power base rate case, the Commission eliminated the subsidies paid by Rate IGS. The subsidy elimination for industrial customers that compete nationally and internationally was justified on cost of service and economic development grounds. Notwithstanding this, as shown in Table 1, Rate IGS is once again paying substantial subsidies.[194]

Nevertheless, Kentucky Power proposes to maintain these current inter-class subsidies in its rates. In other words, the Company has calculated its proposed rates by: 1) first determining the revenue increases for each rate class that is needed to produce an equal rate of return (the Company's proposed rate of return of

[193] Baron Testimony at 9:1-5.
[194] Baron Testimony at 9:7-18.

6.54%); and then 2) increasing or decreasing these cost based revenue increases using the current level of subsidies shown in Table 1. For example, the current residential class subsidy is $31.8 million. This is also the residential class subsidy at proposed rates. Similarly, the current IGS subsidy is $9.4 million and that is maintained at proposed rates.[195]

KIUC continues to believe that for industrial manufacturers subsidies should be reduced and ultimately eliminated in the long-term. Competitive electric rates are critical to the economic health of Kentucky industrial customers who compete both nationally and internationally. And such industrial customers are critical to the economic health of the Commonwealth, providing high-paying jobs with multiplier benefits that local commercial business cannot provide.

However, given the unique facts at issue in this case, Kentucky Power's proposal to maintain current subsidies in its proposed rates is reasonable. The AG supports maintenance of the current subsidies. This case is occurring during an unprecedented pandemic and economic disruption that the U.S. and Kentucky have not experienced since the 1930s. Given the unique and unprecedented economic environment in Kentucky, and the fact that any base rate increase may be suspended through the use of EDIT, the Commission should adopt the Company's proposed revenue allocation, which maintains current subsides at proposed rates.[196]

For the same reasons, in the event that the final Commission approved overall revenue increase is less than the Company's requested $70.1 million increase, the reduction should be applied on a uniform percentage basis to the Company's proposed revenue increases. For example, if the Commission awards the Company 60% of its requested increase, then the Company's proposed increase to all rate schedules should be reduced by 40%.[197]

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[195] Baron Testimony at 10:1-9.
[196] Baron Testimony at 10:11-11:2.
[197] Baron Testimony at 11:4-19.

L. The Commission Should Approve Kentucky Power's Proposed Net Metering Service Tariff.

Kentucky Power proposes to close its current Net Metering Service tariff to new customers on January 1, 2021 and replace it with a Net Metering Service tariff ("NMS II"), which would modify the rate that net metering customers are paid for their excess energy that is exported to the grid. The Company says that its proposal is consistent with Kentucky SB 100 ("the Net Metering Act"). AG-KIUC generally agree with Kentucky Power's request.

The current price paid for such exported energy is not consistent with the value of this energy or avoided cost and therefore represents a subsidy that is paid by non-participating Kentucky Power customers to solar customers.[198] In short, the current net metering scheme provides a subsidy to customers who take service under that tariff and other solar interests; this subsidy is at the expense of traditional utility customers. Further, those who take service under the net metering tariff are likely wealthier than traditional customers given that a substantial outlay is required to fund the installation of distributed generation on one's home. Thus, the current net metering tariff not only provides a subsidy, that subsidy is highly regressive to boot.

The current payment rate reflects the embedded cost of providing full service to residential customers, including the full fixed costs of generation, transmission, distribution, and general plant, such as Kentucky Power office buildings. Exported solar energy clearly does not avoid all such costs, but that is what is assumed in the current payment rate to solar customers for their excess energy. Even under the Company's proposed tariff, solar customers are able to use their solar generation to fully offset the customer's own usage, which means that the solar customer is being paid, implicitly, at the full residential tariff rate for this portion of their solar generation. Kentucky Power's proposed tariff only changes the payment rate for the excess portion of the customer's solar generation. It is very likely that substantial subsidies would still continue even if the Company's proposal in this case is adopted.[199]

[198] Baron Testimony at 21:17-22:2.
[199] Baron Testimony at 22:4-18.

Under an ideal non-subsidized rooftop solar rate, a solar customer would have a 100% buy/sell rate. The customer would pay the full residential tariff rate for 100% of the customer's energy usage and receive Kentucky Power's avoided cost for 100% of the customer's solar generation. Even under the Company's revised net metering tariff, the customer will implicitly continue to receive the residential tariff rate as payment for solar generation that is available to offset the customer's own household usage each month (i.e., the portion of a customer's total solar generation that is netted against a customer's usage).[200]

Kentucky Power's proposed excess energy payment rate include estimates of both avoided energy cost and avoided capacity cost that are based on an analysis of an estimate of net excess solar energy by hour.[201] The Company bases its avoided energy cost value on a weighted on-peak/off-peak calculation of PJM locational marginal prices, as used in the Company's Cogen SPP rate calculation. The on-peak weighting, reflecting an estimate of solar output, is 71% and the off-peak weighting is 29%. To calculate avoided generation and transmission cost, Kentucky Power has estimated the coincidence of solar excess energy with a probability weighted 5 CP demand (generation) and 12 CP demand (transmission).[202]

Kentucky Power's proposed excess energy payment is a reasonable estimate of the value of netted excess rooftop solar energy. While there certainly could be more detailed and comprehensive methodologies used to develop an excess energy avoided cost rate, the Company's calculation is reasonable and provides solar customers a fair compensation for their excess energy. The proposed rate represents a more reasonable payment for excess energy than the current rate, which pays customers at the same tariff rate at which they purchase energy from the Company.[203]

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[200] Baron Testimony at 23:1-8.
[201] Vaughan Exhibit AEV-R5.
[202] Baron Testimony at 23:10-24:2.
[203] Baron Testimony at 24:4-12.

M. The Commission Should Initiate An Investigation Of Kentucky Power's PJM Transmission Charges, Including Whether The Company Should Continue In The Current AEP East Transmission Agreement.

Kentucky Power currently participates in PJM pursuant to the AEP East Transmission Agreement ("Transmission Agreement") among the AEP East Operating Companies, which include Kentucky Power, Appalachian Power Company, Wheeling Power Company, Kingsport Power Company, Ohio Power Company and Indiana Michigan Power Company. As agent for these Operating Companies, AEP receives a bill from PJM for the combined transmission charges incurred by all of the Operating Company LSEs under the AEP OATT. These charges are then allocated to AEP on the basis of the AEP East Companies' contribution to the combined 1 CP demand of the Operating Companies. They are then reallocated to each Operating Company on a 12 CP basis pursuant to the Transmission Agreement.[204]

Kentucky Power's PJM transmission expenses are growing rapidly, as Company witness Vaughan confirms in his testimony, stating:

> …The adjusted test year Kentucky retail jurisdictional total of net PJM LSE OATT charges and credits included in base rates is $96,896,495. This amount has grown from $74,377,364 in Case No. 2017-00179, and from $53,779,456 in Case No. 2014-00396. <u>This single expense is now 16% of the Company's total proposed revenues</u>. (emphasis added).[205]

As shown in Table 2 below, PJM NITS charges comprise over 90% of Kentucky Power's PJM transmission expenses.[206]

[204] Baron Testimony at 12:1-13.
[205] Vaughan Testimony at 33.
[206] Baron Testimony at 13:18-14:2.

Table 2

Total costs charged to KPCo for the most recent 12 month period available

Account		Total	
4561002	RTO Formation Cost Recovery	$	112,115
4561005	PJM Point to Point Trans Svc	$	(1,075,140)
4561035	PJM Affiliated Trans NITS Cost	$	40,768,053
4561036	PJM Affiliated Trans TO Cost	$	166,952
4561060	Aff PJM Trans Enhancement Cost	$	931,594
5650012	PJM Trans Enhancement Charge	$	1,245,983
5650015	PJM TO Serv Exp - Aff/ inc. Transco	$	199,951
5650016	PJM NITS Expense - Affiliated/ inc. Transco	$	41,062,857
5650019	Aff PJM Trans Enhancement Exps	$	5,585,557
5650021	PJM NITS Expense - Non-Affiliated	$	307,683
Grand Total		$	89,305,604
	NITS Charges (Affiliate, Non-Affiliate)	$	81,830,909

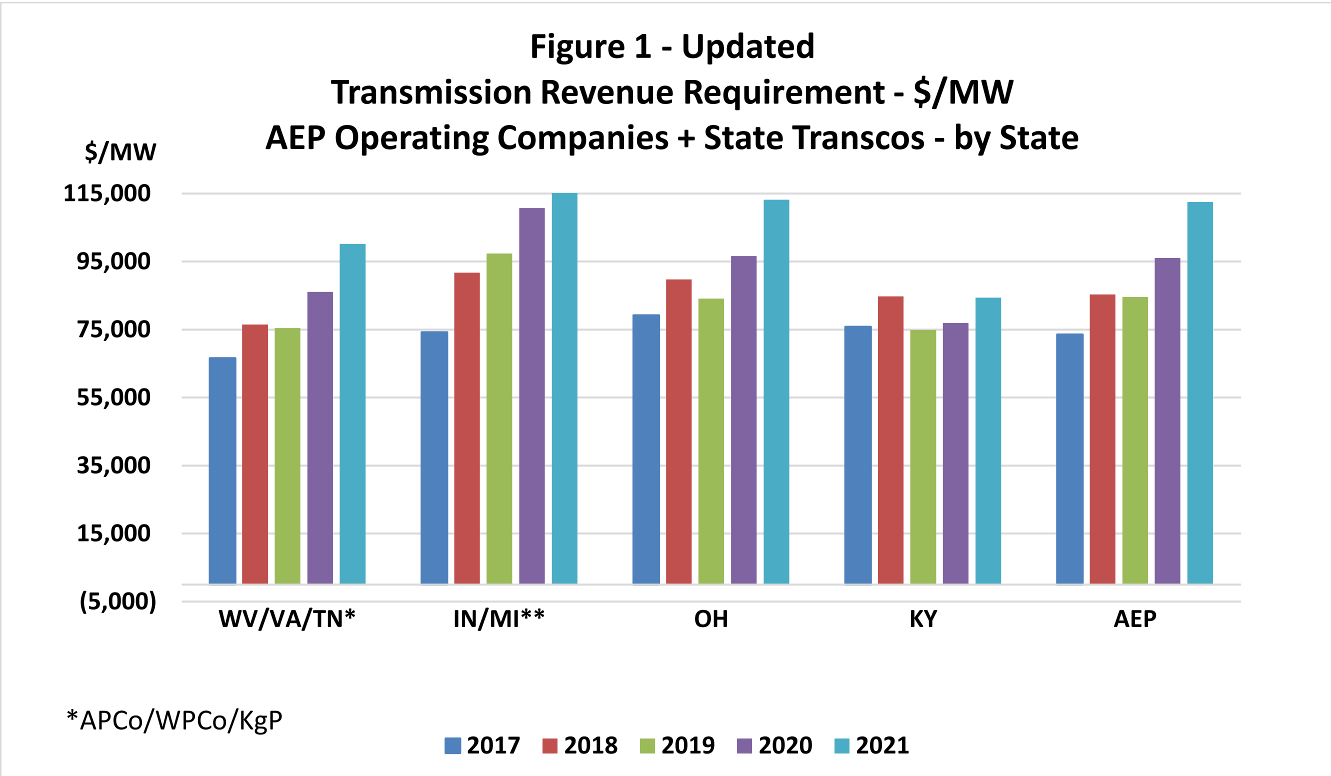
Source: KPCO_R_KIUC_AG_1_45_Attachment_1

Kentucky Power's share of the AEP East PJM NITS transmission charges is not consistent with the Company's transmission investment. Kentucky Power is being allocated a substantially greater share of the AEP East pooled PJM NITS charges than it would pay if it were a standalone Company. The total AEP transmission zone NITS charges are comprised of the revenue requirements associated with transmission investment of the AEP East Operating Companies plus each State Transco. About 85% of these Operating Company and State Transco revenue requirements are allocated to the AEP LSE and 15% are allocated to other non-AEP network service customers (primarily municipal utilities) in the AEP PJM Zone. Kentucky Power's 12 CP share of these costs are currently about 5.6% of the total AEP LSE amount.[207]

AG-KIUC witness Baron's Updated Figure 1 provides a graphic comparison for the years 2017 through 2021 for KPCo and each of the other AEP Companies,[208] normalizing the total revenue requirements charged to each Company by its 12 CP MW, which is the allocation basis for these costs. As can be seen

[207] Baron Testimony at 15:1-12.
[208] For graphic clarity, the APCo, WPCo and Kingsport Power costs are grouped together.

from the chart, Kentucky Power's average transmission revenue requirement per MW based on its own costs plus the costs of the Kentucky Transmission Company are substantially lower than the costs that KPCo is charged under the Transmission Agreement allocation.[209]



In 2021, the difference in total revenue requirements between Kentucky Power's actual costs (including the Kentucky Transco revenue requirements) and the amount allocated to the Company under the Transmission Agreement will be about $27.689 million. This is 25% above the Kentucky Power standalone transmission costs. This means that other AEP Operating Companies are being allocated much lower costs under the Transmission Agreement than would be the case if they were charged their standalone revenue requirements.[210] In other words, there are winners and losers and Kentucky Power is a loser.

Based upon AEP's earnings presentations, significant growth in transmission rate base is expected to continue. AEP's 2020-2024 capital budget forecast for new transmission spending in PJM is $9.772

[209] Baron Testimony at 15:14-16:10.
[210] Baron Testimony at 17:1-7.

Billion. Approximately 5.6% of the AEP LSE 85% share of these expenditures [approximately 15% is paid for by municipal load in the AEP zone], or $465 million, will be allocated to Kentucky Power.[211] Therefore, the 2021 $27.689 million annual premium charged to Kentucky under the Transmission Agreement is likely to increase.[212]

Table 3 Updated shows the annual growth rates for each AEP Company in both 12 CP demand and transmission revenue requirements over the period 2017 to 2021. For example, I&M has had an annualized decline in its 12 CP share of AEP LSE costs, while its transmission revenue requirements have been growing by 15.19% per year. In comparison, Kentucky Power has had almost no change in its 12 CP demand and has increased its transmission revenue requirements by a much lower 2.75% per year. This has resulted in Kentucky Power receiving a disparate share of AEP system-wide NITS costs relative to its standalone transmission revenue requirements.[213]

Table 3-Updated
Annual Growth in Transmission Revenue Requirements and 12 CP Demand - 2017 to 2021

	WV/VA/TN	IN/MI	OH	KY	AEP LSE
12 CP	0.84%	-0.33%	1.37%	0.04%	0.82%
Transmission Rev. Req.	11.47%	15.19%	10.47%	2.75%	11.87%

Kentucky Power could withdraw from the AEP East Transmission Agreement. The Company has the right to withdraw from the AEP East Transmission Agreement upon three years notice. In that event, Kentucky Power would become a standalone PJM member within the AEP zone. But that won't fix the problem. It would only change Kentucky Power's allocated share of total AEP transmission costs from 12 CP to 1 CP.

To fix the problem of Kentucky customers unreasonably subsidizing customers in other states, Kentucky Power must be responsible for only its own transmission costs. Since the allocation of these

[211] Direct Testimony of Stephen J. Baron at 17.
[212] Baron Testimony at 17:9-14.
[213] Baron Testimony at 17:19-18:14.

transmission costs is governed by a FERC approved PJM tariff, addressing the disparity would likely require approval by the FERC. PJM tariffs and agreements can be modified if the FERC determines that the current provisions are not just and reasonable.

In Kentucky Power's last rate case the Commission recognized that the multi-state AEP system may not be serving Kentucky's interests, stating, "…the Commission recognizes that Kentucky Power's interests may not be aligned with the interests of other AEP operating companies. The Commission is aware that PJM bills AEP based on a one-coincident peak methodology, and that AEP subsequently allocates those costs to its operating companies using a twelve-coincident peak methodology. The Commission finds that Kentucky Power should file an annual report with the supporting calculations used by AEP to allocate these costs."[214] Additionally, the Commission "…strongly encourage[d] Kentucky Power to recognize that it must make a determination regarding its participation in PJM that aligns with the interests of Kentucky Power and its ratepayers."[215]

Kentucky Power has not conducted any economic analyses on its own to determine if it should continue participating in the AEP Transmission Agreement.[216] However, that issue should be explored by the Commission. As such, AG-KIUC recommend that the Commission initiate an investigation following completion of this rate case. This investigation should consider whether, in the long-term, it is in the public interest for Kentucky Power to continue participating in the AEP East Transmission Agreement or whether Kentucky Power should seek to become an individual member of PJM or form a combined zone with another Kentucky utility (e.g. East Kentucky Power Cooperative). The Company should be required to present economic analyses and testimony which demonstrates that continued participation in the Transmission Agreement is in the public interest.[217] Explosive transmission growth in other states that is allocated to

[214] Order, Case No. 2017-00179 (January 18, 2018) at 74.
[215] Id. at 74.
[216] Exhibit SJB-3; Kentucky Power Response to AG-KIUC Item No. 1-43.
[217] Baron Testimony at 20:5-17.

Kentucky is a problem. Therefore, active Commission involvement is appropriate.

Unsuprisingly, Kentucky Power opposes AG-KIUC's request for an investigation of transmission. Kentucky Power argues that "AG/KIUC's request [for an investigation] is unlawful."[218] Contrary to Kentucky Power's assertions, a Commission investigation is not preempted by federal law; nor would it violate the filed rate doctrine.

AG-KIUC are not asking the Commission to open an investigation so that this Commission may unilaterally change the FERC approved Transmission Agreement. That would be preempted. Instead, we are primarily seeking a Commission review of whether grounds exist to request that FERC amend its prior approval of the Transmission Agreement. That is exactly how the process is supposed to work. FERC approved the Transmission Agreement under Section 205 of the Federal Power Act in Docket No. ER09-1279, and FERC has authority to amend that approval.

In addition to the Commission or AG-KIUC requesting that FERC amend its approval of the the Transmission Agreement, a second and related issue for investigation is whether Kentucky Power has the right to lower its costs under the existing Transmission Agreement as currently approved.

Section 10.2 of the Transmission Agreement provides that "it is expressly understood that any Member [Kentucky Power] … shall be entitled, at any time and from time to time, unilaterally to make application to the FERC for a change in rates, charges, classification of service, or any rule, regulation or contract relating thereto, or to make any change in or supersede in whole or in part any provision of this Agreement, under Section 205 of the Federal Power Act." Kentucky Power's heretofore undefined options regarding participation in the FERC-approved Transmission Agreement are worthy of investigation. Whether and to what extent Kentucky Power has grounds to take specific actions to reduce those expenses are within the Commission's authority to review.

[218] See Kentucky Power's Post-Hearing Brief at 61.

VII. CONCLUSION

WHEREFORE, for the reasons discussed above, the Commission should adopt the AG-KIUC recommendations in this proceeding.

Respectfully submitted,

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