**COMMONWEALTH OF KENTUCKY**

**BEFORE THE PUBLIC SERVICE COMMISSION**

In the Matter of:

| | | |
|---|---|---|
| AN ELECTRONIC EXAMINATION OF THE APPLICATION OF THE FUEL ADJUSTMENT CLAUSE OF KENTUCKY POWER COMPANY FROM NOVEMBER 1, 2022 THROUGH OCTOBER 31, 2024 | )<br>)<br>)<br>)<br>) | Case No. 2025-00338 |

**DIRECT TESTIMONY OF**

**LERAH M. KAHN**

**ON BEHALF OF KENTUCKY POWER COMPANY**

**DIRECT TESTIMONY OF**
**LERAH M. KAHN ON BEHALF OF**
**KENTUCKY POWER COMPANY**
**BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY**

**CASE NO. 2025-00338**

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## EXHIBITS

| Exhibit | Description |
|---|---|
| EXHIBIT LMK-1 | Supporting excel for Tables LMK-1 and LMK-2 |
| EXHIBIT LMK-2 | The Brattle Group final study |

# DIRECT TESTIMONY OF LERAH M. KAHN ON BEHALF OF KENTUCKY POWER COMPANY BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

**CASE NO. 2025-00338**

## I. INTRODUCTION

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

A. My name is Lerah M. Kahn, and my position is Manager of Regulatory Services, Kentucky Power Company ("Kentucky Power" or the "Company"). My business address is 1645 Winchester Avenue, Ashland, Kentucky 41101.

## II. BACKGROUND

**Q. PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND BUSINESS EXPERIENCES.**

A. In 2009, I earned a Bachelor of Arts degree in History from the University of Guelph in Guelph, Ontario, Canada. Additionally, in 2010 I received a Paralegal diploma from Algonquin Careers Academy in Mississauga, Ontario, Canada.

From 2013 through 2018, I worked at Sogefi Group Inc., a global supplier for the automotive industry, as a material planner and accounting specialist. I accepted the position of Regulatory Consultant with Kentucky Power Company in July 2018, and I was promoted to my current position as Manager of Regulatory Services in February 2023.

**Q. WHAT ARE YOUR PRINCIPAL AREAS OF RESPONSIBILITY WITH KENTUCKY POWER?**

A. As Manager of Regulatory Services, I am responsible for the supervision and direction of Kentucky Power's Regulatory Services Department, which has responsibility for all rate and regulatory matters involving the Company.

**Q. HAVE YOU PREVIOUSLY TESTIFIED IN ANY REGULATORY PROCEEDINGS?**

A. Yes. I have submitted testimony before this Commission in Case No. 2019-00389 (application for approval of the Company's 2019 Environmental Compliance Plan ("ECP")), Case No. 2020-00133 (Commission's examination of the Company's Environmental Surcharge mechanism for the two-year billing period ending June 30, 2019), Case No. 2020-00174 (base rate case), Case No. 2021-00004 (application for approval of the Company's 2021 ECP), Case No. 2022-00387 (application for a special contract), Case No. 2023-00159 (base rate case), Case No. 2023-00372 (Commission's examination of the Company's Environmental Surcharge mechanism for the four-year billing period ending June 30, 2023), Case No. 2024-00136 (Commission's examination of the Company's Fuel Adjustment Clause mechanism for the six-month period ending April 30, 2023), Case No. 2024-00344 (Application for Advanced Metering Infrastructure), and Case No. 2025-00175 (Application for approval to make the capital investments necessary to continue receiving capacity and energy from the Mitchell Generating Station).

## III. PURPOSE OF TESTIMONY

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

A. The purpose of my testimony is to support the Company's decision to maintain the current base fuel rate. I also explain the major terms of the Settlement Agreement in the Company's last two-year fuel adjustment clause ("FAC") case, Case No. 2023-00008, and how it did not affect the calculation of the FAC during the period under review (November 1, 2022 through October 31, 2024, the "Review Period"). Additionally, I address, at a high level, any cost-benefit analysis the Company has performed regarding its participation in PJM Interconnection, LLC ("PJM").

The remaining subjects identified in the Commission's December 19, 2025 Order are addressed by Company Witnesses Chilcote, Stutler, Mell, Snodgrass, and Stegall as follows:

| Witness | Ordering Paragraph Item 6 Topic (if applicable) | Description |
|---|---|---|
| Kimberly K. Chilcote | | Overview of the coal market during the Review Period; |
| | a. | The reasonableness of Kentucky Power's coal procurement practices during the Review Period; |
| | b. | Coal suppliers' adherence to contract delivery schedules during the Review Period; |
| | c. | Kentucky Power's efforts to ensure coal suppliers' adherence to contract delivery schedules during the Review Period; |
| | d. | Kentucky Power's efforts to maintain the adequacy of its coal supplies in light of any coal supplier's inability or unwillingness to make contract coal deliveries; |
| | e. | Any changes in coal market conditions that occurred during the Review Period or that Kentucky Power expects to occur within the next |

| | | |
|---|---|---|
| | | two years that have significantly affected or will significantly affect Kentucky Power's coal procurement practices; and |
| | g. | Actions taken by Kentucky Power to mitigate high fuel or purchased power related costs for its customers. |

| | | |
|---|---|---|
| Clinton M. Stutler | | Overview of the natural gas market during the Review Period; |
| | a. | The reasonableness of Kentucky Power's natural gas procurement practices during the Review Period; and |
| | g. | Actions taken by Kentucky Power to mitigate high fuel or purchased power related costs for its customers. |

| | | |
|---|---|---|
| Jason M. Stegall | f. | Any changes in the wholesale electric power market that occurred during the Review Period or that Kentucky Power expects to occur within the next two years that have significantly affected or will significantly affect Kentucky Power's electric power procurement practices; |
| | g. | Actions taken by Kentucky Power to mitigate high fuel or purchased power related costs for its customers; |
| | h. | Any planned outages that extended beyond the estimated time of the outage and how Kentucky Power addressed the extended outage, and any resulting capacity and energy shortfalls; |
| | i. | Whether Kentucky Power engaged in any off systems sales or intersystem sales to offset high fuel or power costs during the period under review; |
| | j. | How Kentucky Power bids its generating units into PJM energy markets, including, but not limited to the following: how Kentucky Power determines the manner in which individual generating units are offered into PJM's day ahead market (must run, economic dispatch etc.); who makes those decisions; and what level of control PJM has over the dispatch of Kentucky Power's generating units; and |
| | k. | How coal consumption is recorded for a unit that is in reserve shutdown. |

| | | |
|---|---|---|
| Joshua D. Snodgrass | h. | Any planned outages at the Mitchell Plant that extended beyond the estimated time of the outage and how Kentucky Power addressed the extended outage. |

| | | |
|---|---|---|
| David L. Mell | h. | Any planned outages at the Big Sandy Plant that extended beyond the estimated time of the outage and how Kentucky Power addressed the extended outage. |

| | | |
|---|---|---|
| Lerah M. Kahn | l. | Any cost-benefit analysis Kentucky Power has performed regarding its participation in PJM; and |
| | m. | Explain in depth how the Stipulation in Case No. 2023-00008 impacted Kentucky Power's calculation of its FAC during the period under review. |

**Q. ARE YOU SPONSORING ANY EXHIBITS?**

A. Yes, I am sponsoring the following exhibits:

- Exhibit LMK-1: Supporting excel file for Tables LMK-1 and LMK-2
- Exhibit LMK-2: The Brattle Group final study

**Q. WERE THESE EXHIBITS PREPARED BY YOU OR UNDER YOUR DIRECTION?**

A. Yes.

## IV. BASE FUEL RATE

**Q. WHAT IS THE COMPANY'S CURRENT BASE FUEL RATE, AND WHEN DID THE COMPANY LAST MODIFY IT?**

A. In its December 13, 2024 Order in Case No. 2023-00008, the Commission approved the Company's current base fuel rate of 3.380 cents per kilowatt-hour ("kWh"), which was an increase from the previously-approved rate of 2.612 cents per kWh. The current base fuel rate of 3.380 cents per kWh was placed into effect for service rendered on or after December 31, 2024.

**Q. WHAT BASE FUEL RATE IS THE COMPANY PROPOSING IN THIS CASE?**

A. The Company is proposing to maintain the current base fuel rate at 3.380 cents per kWh.

**Q. PLEASE DESCRIBE THE PROCESS THE COMPANY USED IN REACHING ITS RECOMMENDATION TO MAINTAIN THE CURRENT BASE FUEL RATE OF 3.380 CENTS PER KWH.**

A. The Company employed its typical practice in determining whether to modify the current base fuel rate, including examining both historical fuel costs during the Review Period and projected fuel costs for the years 2026, 2027, and 2028. Table LMK-1 provides the Company's historical fuel costs during the Review Period and compares them to the base fuel rate in effect during each month of the Review Period, as well as to the Company's current base fuel rate. The average fuel rate for the two-year Review Period was 3.778 cents per kWh, which was 0.398 cents greater than the current base fuel rate. During the Review Period, the cost of fuel fluctuated between a high of 6.368 cents per kWh (January 2022) to a low of 3.051 cents per kWh (May 2024), as demonstrated on Table LMK-1.

| Table LMK-1 | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| Year | Month | Final Cost Pg 5 | Total Sales Pg 3 | Monthly Fuel Rate in Cents per kWh (3) / (4) | % Change from Nov22-Oct24 Avg | Base Fuel Rate in Cents per kWh Pg 1 | Cents per kWh Above or (Below) Base Fuel Rate (5) - (6) | Current Base Fuel Rate in Cents per kWh Per 2023-00008 | Cents per kWh Above or (Below) Current Base Fuel Rate (5) - (8) |
| (1) | (2) | (3) | (4) | (5) | | (6) | (7) | (8) | (9) |
| 2022 | November | $ 28,062,246 | 440,706,130 | 6.368 | 69% | 2.612 | 3.756 | 3.380 | 2.988 |
| 2022 | December | $ 32,296,542 | 530,871,212 | 6.084 | 61% | 2.612 | 3.472 | 3.380 | 2.704 |
| 2023 | January | $ 20,863,053 | 499,846,850 | 4.174 | 10% | 2.612 | 1.562 | 3.380 | 0.794 |
| 2023 | February | $ 14,588,781 | 421,121,053 | 3.464 | -8% | 2.612 | 0.852 | 3.380 | 0.084 |
| 2023 | March | $ 14,261,261 | 451,733,027 | 3.157 | -16% | 2.612 | 0.545 | 3.380 | -0.223 |
| 2023 | April | $ 13,597,999 | 388,944,272 | 3.496 | -7% | 2.612 | 0.884 | 3.380 | 0.116 |
| 2023 | May | $ 12,336,153 | 398,514,364 | 3.096 | -18% | 2.612 | 0.484 | 3.380 | -0.284 |
| 2023 | June | $ 13,457,845 | 417,684,971 | 3.222 | -15% | 2.612 | 0.610 | 3.380 | -0.158 |
| 2023 | July | $ 16,391,425 | 478,933,865 | 3.422 | -9% | 2.612 | 0.810 | 3.380 | 0.042 |
| 2023 | August | $ 16,708,140 | 467,128,731 | 3.577 | -5% | 2.612 | 0.965 | 3.380 | 0.197 |
| 2023 | September | $ 13,661,588 | 411,034,614 | 3.324 | -12% | 2.612 | 0.712 | 3.380 | -0.056 |
| 2023 | October | $ 13,451,852 | 385,659,292 | 3.488 | -8% | 2.612 | 0.876 | 3.380 | 0.108 |
| 2023 | November | $ 16,265,612 | 443,997,586 | 3.663 | -3% | 2.612 | 1.051 | 3.380 | 0.283 |
| 2023 | December | $ 17,795,663 | 463,175,334 | 3.842 | 2% | 2.612 | 1.230 | 3.380 | 0.462 |
| 2024 | January | $ 24,185,079 | 617,468,853 | 3.917 | 4% | 2.612 | 1.305 | 3.380 | 0.537 |
| 2024 | February | $ 18,502,948 | 436,331,073 | 4.241 | 12% | 2.612 | 1.629 | 3.380 | 0.861 |
| 2024 | March | $ 15,124,068 | 425,311,577 | 3.556 | -6% | 2.612 | 0.944 | 3.380 | 0.176 |
| 2024 | April | $ 12,657,058 | 397,483,028 | 3.184 | -16% | 2.612 | 0.572 | 3.380 | -0.196 |
| 2024 | May | $ 12,566,487 | 411,878,407 | 3.051 | -19% | 2.612 | 0.439 | 3.380 | -0.329 |
| 2024 | June | $ 16,824,281 | 457,765,100 | 3.675 | -3% | 2.612 | 1.063 | 3.380 | 0.295 |
| 2024 | July | $ 18,576,640 | 477,823,165 | 3.888 | 3% | 2.612 | 1.276 | 3.380 | 0.508 |
| 2024 | August | $ 16,584,826 | 463,052,563 | 3.582 | -5% | 2.612 | 0.970 | 3.380 | 0.202 |
| 2024 | September | $ 13,306,331 | 399,193,129 | 3.333 | -12% | 2.612 | 0.721 | 3.380 | -0.047 |
| 2024 | October | $ 15,436,148 | 399,930,296 | 3.860 | 2% | 2.612 | 1.248 | 3.380 | 0.480 |
| **Average Nov 2022 - Oct 2024** | | | | **3.778** | | | **1.166** | | **0.398** |
| **Median Nov 2022 - October 2024** | | | | **3.566** | | | **0.954** | | **0.186** |

Table LMK-2 below provides the Company's projected fuel costs for calendar years 2026, 2027, and 2028. The projected fuel cost on a per kWh basis for each of those years (3.640, 3.710, and 3.780, respectively) is close to the Company's current base fuel rate of 3.380 cents per kWh. The average of the projected fuel costs (3.710 cents per kWh) also is similar to the historical average of 3.778 cents per kWh for the Review Period.

| **Table LMK-2<br>Fuel Cost and Sales Projections** | | | | | |
|---|---|---|---|---|---|
| **Year of Projection** | **Projected Fuel Cost** | **Projected kWh Sales** | **Projected Fuel Cost in cents/kWh** | **Fuel Cost in Current Base Rates in cents/kWh** | **Difference in Fuel Cost in cents/kWh** |
| 2026 | $206,065,417 | 5,656,497,000 | 3.640 | 3.380 | 0.260 |
| 2027 | $209,214,565 | 5,634,756,000 | 3.710 | 3.380 | 0.330 |
| 2028 | $212,132,132 | 5,613,181,000 | 3.780 | 3.380 | 0.400 |
| Average | | | 3.710 | 3.380 | 0.330 |

Exhibit LMK-1 is comprised of the excel file supporting both Tables LMK-1 and LMK-2.

**Q. IS IT REASONABLE TO MAINTAIN THE CURRENT BASE FUEL RATE OF 3.380 CENTS PER KWH?**

A. Yes. The current base fuel rate is only 0.398 cents per kWh less than the average fuel cost during the Review Period, and only 0.330 cents per kWh less than the projected average fuel cost for the years 2026 through 2028. Given how close the current base fuel rate is to these metrics, it is reasonable to maintain the current base fuel rate. Maintaining the current base fuel rate promotes rate continuity for customers and minimizes the administrative burden on Kentucky Power and the Commission that would result from changing the base fuel rate. Maintaining the *status quo* means that customers will continue to be billed using the current base fuel rate that has been in effect for more than a year and that they have come to expect. Kentucky Power also would not be required to file, and the Commission would not be required to review and approve, additional tariff sheets, as all rates and terms and conditions of service in the current version of Tariff F.A.C. would remain the same. Moreover, because fuel costs are pass-through costs and the FAC is trued-up every month, customers will pay no more and no less than the fuel costs actually incurred by Kentucky Power, regardless of where the base fuel rate is set. The cons or burdens of modifying the base fuel rate in this proceeding by a nominal amount of approximately 0.3 or 0.4 cents per kWh in order to more closely conform to either the historical monthly fuel cost during the

Review Period, or the projected fuel costs for 2026 through 2028, outweigh the potential pros or benefits of doing so.

For these reasons, it is reasonable to maintain the current base fuel rate of 3.380 cents per kWh.

## V. SETTLEMENT AGREEMENT IN CASE NO. 2023-00008

**Q. PLEASE PROVIDE AN OVERVIEW OF THE TERMS OF THE SETTLEMENT AGREEMENT APPROVED IN CASE NO. 2023-00008.**

A. In Case No. 2023-00008, Kentucky Power entered into a full Settlement Agreement with both of the intervenors in that case, including the Attorney General and Kentucky Industrial Utility Customers, Inc. The Commission approved that Settlement Agreement by its Order dated December 13, 2024. Generally, the Settlement Agreement provided that the Company would 1) prospectively modify the peaking unit equivalent ("PUE") calculation to use a startup cost component of $4.62 per MWh and 2) provide a total $16.9 million in credits to customers to reduce the cost of fuel over the winter months of 2025 (January through April) and 2026 (January through April). Company Witness Stegall provides additional detail regarding the PUE and how the Settlement Agreement modifications to the startup cost component affect its calculation.

Upon the Commission's approval of the Settlement Agreement in Case No. 2023-00008, the Company agreed to provide to customers half of the $16.9 million fuel credit over four consecutive months beginning with January 2025 billing. Upon the Commission's approval of a settlement agreement in this case, the Company agreed to provide to customers the remaining half of the $16.9 million fuel credit over four consecutive months beginning with January 2026 billing.

Kentucky Power, the Attorney General, and KIUC recently moved the Commission for leave to amend the Settlement Agreement ("Amended Settlement Agreement") to account for the fact that the Commission had not yet opened nor concluded this proceeding and so that Kentucky Power could go ahead and provide the remaining fuel credits beginning with January 2026 billing to provide rate relief to customers during the winter heating months.[1] The Commission granted that motion. Pursuant to the Amended Settlement Agreement, the fuel credit to customers that began with January 2026 billing is still contingent upon the Commission's approval, without modification, of a settlement agreement to be entered into in this proceeding. If that settlement agreement is not approved without modification, then Kentucky Power is entitled under the Amended Settlement Agreement to recoup those credits from customers under terms to be established by subsequent Commission order.

**Q. DOES THE AMENDED SETTLEMENT AGREEMENT IMPACT KENTUCKY POWER'S CALCULATION OF THE FAC DURING THE REVIEW PERIOD?**

A. No. Because the fuel credits did not begin until January 2025 billing, they did not impact the calculation of the FAC during the Review Period, which ended October 31, 2024. Further, because the startup cost component of the PUE calculation was not

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[1] Joint Motion, *In The Matter Of: An Electronic Examination Of The Application Of The Fuel Adjustment Clause Of Kentucky Power Company From November 1, 2020 Through October 31, 2022*, Case No. 2023-00008 (December 12, 2025).

modified until after the Commission's December 13, 2024 Order in Case No. 2023-00008, it also did not impact the calculation of the FAC during the Review Period.

## VI. COST-BENEFIT ANALYSIS FOR PARTICIPATION IN PJM

**Q. HAS THE COMPANY CONDUCTED ANY COST-BENEFIT ANALYSES REGARDING ITS PARTICIPATION IN PJM?**

A. Yes. The Brattle Group was engaged to provide a review of various potential cost allocation methodologies in response to concerns raised over apportionment of AEP's transmission costs to Kentucky Power in 2023. Exhibit LMK-2 provides the final Brattle Group report resulting from that engagement.[2] It is my understanding that the issue of transmission cost allocation by PJM to Kentucky Power and its AEP affiliates is currently the subject of an open complaint at the Federal Energy Regulatory Commission.

## VII. CONCLUSION

**Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?**

A. Yes, it does.

[2] Kentucky Power also provided a description of the benefits of PJM membership in the Direct Testimony of Joshua D. Burkholder in Case No. 2023-00008.

# AEP Transmission Cost Allocations to Kentucky

**PREPARED BY**

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**PREPARED FOR**

American Electric Power

**JUNE 2024**

Brattle

## NOTICE

This report was prepared for American Electric Power (AEP) in accordance with The Brattle Group's engagement terms. It is intended to be read and used as a whole and not in parts.

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# Executive Summary

This report is intended to provide a review of various potential cost allocation methodologies in response to concerns raised over the apportionment of American Electric Power's ("AEP's") transmission costs to Kentucky Power Company ("Kentucky Power"), one of AEP's utility operating companies ("Opco") within the PJM Interconnection LLC ("PJM") region. In response to the need to refurbish transmission infrastructure and address other grid reliability needs, significant transmission investments have been necessary in the PJM portion of AEP's system ("AEP East"), resulting in a level of investments that is expected to continue at least over the next five years. However, the share of projected investments among the AEP Opcos (and AEP East transmission affiliates, or "Transcos") will likely differ from historically observed patterns, partially because of differences in load growth and because investment needs will be shifting from Opcos that already went through significant refurbishment (such as Ohio Power Company) to Opcos that have not yet done so, including Kentucky Power.

Kentucky Power uses a significant amount of transmission facilities across AEP East, including facilities constructed and owned by other AEP East Opcos and their Transcos. Kentucky Power derives much of its generation and resource adequacy requirements from the facilities that are located beyond the service territory of Kentucky Power. To assess the degree to which Kentucky Power utilizes the balance of the AEP East transmission system, this report discusses each Opco's contribution to transmission use of the larger AEP East transmission system based on power-flow modeling. This flow-based usage analysis uses a summer peak case that provides a measure of transmission use against which the reasonableness of AEP's current and various alternative cost allocation options can be evaluated.

The report also examines alternative cost allocation methods.[1] While these alternative methods also allocate costs that are roughly commensurate with transmission-related benefits received by Kentucky Power and the other AEP East Opcos, a number of considerations support retaining AEP's existing cost allocation method. When compared against fundamental ratemaking principals, many of the evaluated alternative methods revealed disadvantages such as higher volatility, complexity, and a lack of relation to the underlying Opco use of the AEP transmission facilities, compared to the current method implemented by AEP East.

[1] FERC recently issued its new transmission and cost allocation rule, Order 1920, which could impact the cost allocation approaches going forward. Consideration of Order 1920 is outside the scope of this report.

In addition, this report assesses the feasibility of Kentucky Power attempting to become its own standalone PJM transmission zone or join a neighboring PJM zone (outside of the AEP footprint). Reviewing the current PJM rules and agreements indicate this will entail significant challenges and a high degree of regulatory uncertainty. In addition, Kentucky Power leaving PJM's AEP zone would likely result in higher PJM regional transmission cost allocations and an increase in resource adequacy costs. Beyond the feasibility under PJM's processes and agreements, important aspects of this option remain unclear, including the potentially significant costs associated with departing PJM's AEP zone, and whether a standalone Kentucky Power zone would be able to participate in PJM's Fixed Resource Requirement ("FRR") option for resource adequacy.

With these observations, we suggest that maintaining the current cost allocation method within the AEP East pool is the most optimal option going forward for Kentucky Power. The payoffs for the select alternatives, including changing the cost allocation method, and Kentucky Power exiting the AEP East pool, do not appear to be attractive.

This Kentucky-focused report relies on a more extensive report covering all of AEP-East ("AEP Report"), which is presented in the Appendix.

# I. Introduction

## A. Report Scope

AEP has retained The Brattle Group[2] to review and analyze allocations of transmission costs to Kentucky Power as a part of a broader analysis of transmission cost allocation within AEP East. Kentucky Power is one of eleven AEP East operating and transmission companies.[3]

This report discusses a number of questions that have been raised. First, it identifies the issues raised by the Kentucky Public Service Commission ("Commission") related to the allocation of AEP East-wide costs as compared to the cost of transmission owned by Kentucky Power within

[2] The Brattle Group's contributors to this report include Johannes P. Pfeifenberger, T. Bruce Tsuchida, Joe DeLosa III, and Jadon Grove. The views expressed in this report are strictly those of the authors and do not necessarily state or reflect the views of The Brattle Group, Inc. or its clients.

[3] Of the eleven AEP transmission owning and load serving subsidiaries, there are six Opcos (Appalachian Power, Indiana Michigan Power, Kentucky Power, Kingsport Power, Ohio Power, and Wheeling Power) and five Transcos (Appalachian Transmission Company, Indiana Michigan Transmission Company, Kentucky Transmission Company, Ohio Transmission Company, and West Virginia Transmission Company).

its footprint. Second, it reviews the past and projected future Kentucky Power and AEP East system transmission investments and compares the observed trend to AEP East as a whole and the nation broadly. The transmission investments then are compared against the historic and projected future transmission cost allocation percentages among AEP Opcos under the AEP Transmission Agreement ("TA").

Building up on these findings, the report further analyzes how Kentucky Power utilizes the AEP East transmission system. To approximate Kentucky Power's use of AEP's system, we present a flow-based usage analysis that provides a snapshot of each Opco's contribution to the power flowing on AEP East transmission facilities to serve AEP East loads. Other specific drivers of Kentucky Power's use of the AEP East system are reviewed and discussed.

Finally, the report proceeds to summarize the impacts, benefits, and drawbacks of various alternative transmission cost allocation methodologies. The report also evaluates the challenges encountered and cost implications if Kentucky Power were to create its own standalone PJM zone or join a neighboring zone outside the current AEP East footprint.

## B. Concerns Raised before the Kentucky Public Service Commission

In recent rate proceedings before the Commission, commenters have raised concerns that the amounts of AEP East transmission costs assigned to Kentucky Power have exceeded the costs of AEP's transmission owned by AEP's Kentucky affiliates.[4] The Commission repeated these concerns in its Order on Kentucky Power's 2020 base rate case, mentioning the Attorney General's recommendation that "the Commission open an investigation into whether Kentucky Power should remain in the AEP East Transmission Agreement because Kentucky Power is allocated significantly greater expenses from the AEP East Transmission zone than what Kentucky Power would pay as a standalone transmission zone in AEP."[5] The Commission raised similar concerns regarding wholesale transmission expenses in its recent Order on Kentucky Power's 2023 base rate case.[6]

In addition, the Commission has expressed several other concerns that are beyond the scope of this report. As part of the 2021 Order, the Commission noted certain investments occurring under the auspices of the Kentucky Transco that had previously been under the functional and

[4] Kentucky Public Service Commission, Order, Case No. 2020-00174 (January 13, 2021) at 59.

[5] Ibid.

[6] Kentucky Public Service Commission, Order, Case No. 2023-00159 (January 19, 2024) at 35.

construction responsibility of Kentucky Power. Recently, AEP has clarified in response to the Commission's concerns that it no longer involves the Kentucky Transco in projects related to Kentucky Power's transmission assets.[7]

# II. Analysis of Kentucky Cost Allocation

## A. Kentucky Transmission Investments

### 1. Historical Transmission Investments

As described more fully in the AEP Report, AEP's investment in transmission infrastructure has accelerated in the last decade. This trend is observed across the U.S., motivated by emerging transmission needs, such as the refurbishment of the nation's aging transmission infrastructure. Transmission assets typically have a useful life of approximately 70 years after which they require refurbishment or replacement.[8] However, many of AEP's transmission facilities continue to operate well beyond this life expectancy.[9]

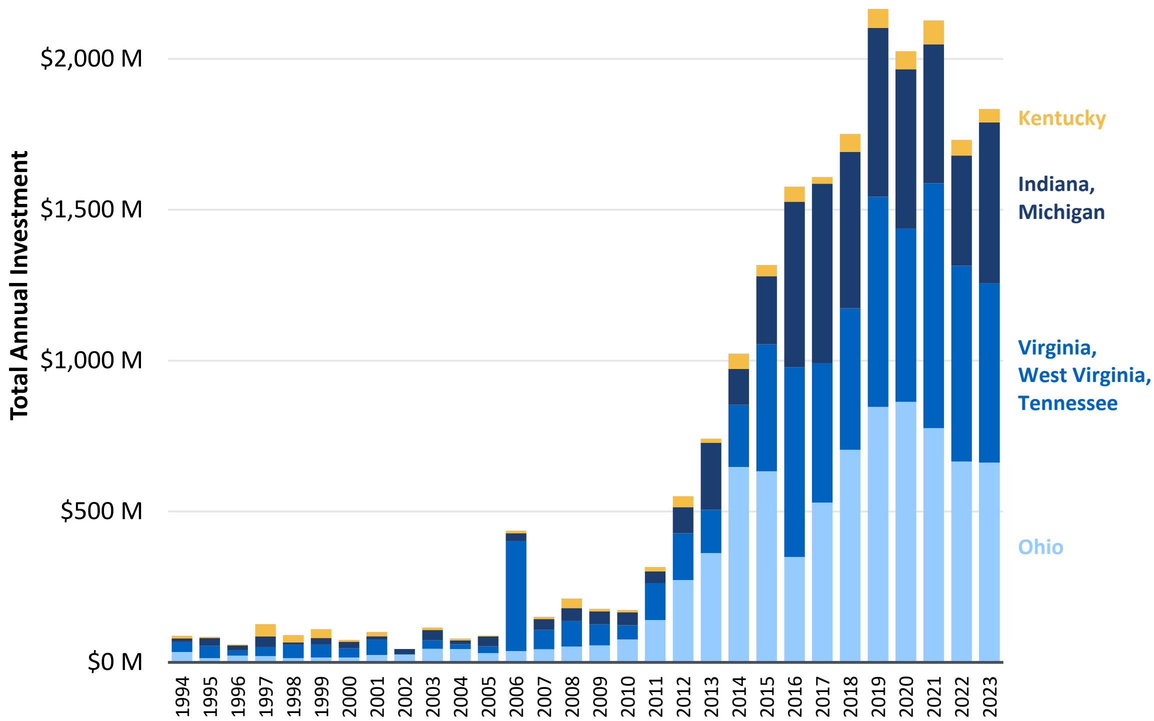
Continued transmission investments in individual states reflect AEP's assessment of system-wide needs. AEP's transmission investments located in individual states therefore do not capture the drivers or beneficiaries of these AEP system-wide investments, as discussed further in Section II.D of this report. As shown in Figure 1, state-specific shares of annual transmission investment vary widely across the years, reflecting in part AEP's assessment of specific asset management needs in its system and in part PJM's identification of regional system needs within the AEP footprint that PJM assigns to be constructed by an AEP affiliate.

7 See Direct Testimony of Joshua Burkholder, KY PSC Case No. 2023-00159 (June 21, 2023) at 12:10-16.

8 See AEP Report at Section II.C.1.

9 See AEP Report at Figure 3.

**FIGURE 1: ANNUAL ADDITIONS TO PLANT IN SERVICE—AEP EAST STATES**




Note: Kingsport Company and Wheeling Power Company, along with West Virginia Transmission Company are included with Appalachian Power Company and Appalachian Transmission Company as part of Virginia, West Virginia, Tennessee. State investment includes Opco and Transco.
Source: AEP Report, Figure 7; The Brattle Group analysis of historical transmission plant additions filed in FERC Form 1s.

Table 1 below summarizes for 2015 to 2023 the states' shares of annual AEP East investments shown in Figure 1 above. Since 2015, Kentucky Power's portion of annual investment shares has remained between 2.5% and 3.7%, with an outlier in 2017, when investment decreased to under $25 million (or 1.4%, as shown in the table). Kentucky Power's share of total AEP East transmission investment during this period was about $468 million, or 3% of the AEP East total investments.

**TABLE 1: ANNUAL SHARES OF AEP TRANSMISSION ADDITIONS BY STATE**

| Year | Virginia, Tennessee, West Virginia | Indiana, Michigan | Kentucky | Ohio |
|---|---|---|---|---|
| **2014** | 20.1% | 11.7% | 4.9% | 63.3% |
| **2015** | 32.0% | 17.1% | 2.8% | 48.0% |
| **2016** | 39.9% | 34.8% | 3.2% | 22.2% |
| **2017** | 28.7% | 37.0% | 1.4% | 32.9% |
| **2018** | 26.8% | 29.6% | 3.4% | 40.2% |
| **2019** | 32.1% | 25.9% | 2.9% | 39.1% |
| **2020** | 28.4% | 26.0% | 3.0% | 42.6% |
| **2021** | 38.1% | 21.7% | 3.7% | 36.5% |
| **2022** | 37.5% | 21.1% | 3.0% | 38.4% |
| **2023** | 32.4% | 29.0% | 2.5% | 36.1% |

Note: Kingsport Company and Wheeling Power Company, along with West Virginia Transmission Company are included with Appalachian Power Company and Appalachian Transmission Company as part of Virginia, West Virginia, Tennessee. State investment includes Opco and Transco.
Source: AEP Report, Table 1. Based on historical transmission plant additions filed in FERC Form 1s.

## 2. Projected Transmission Investments

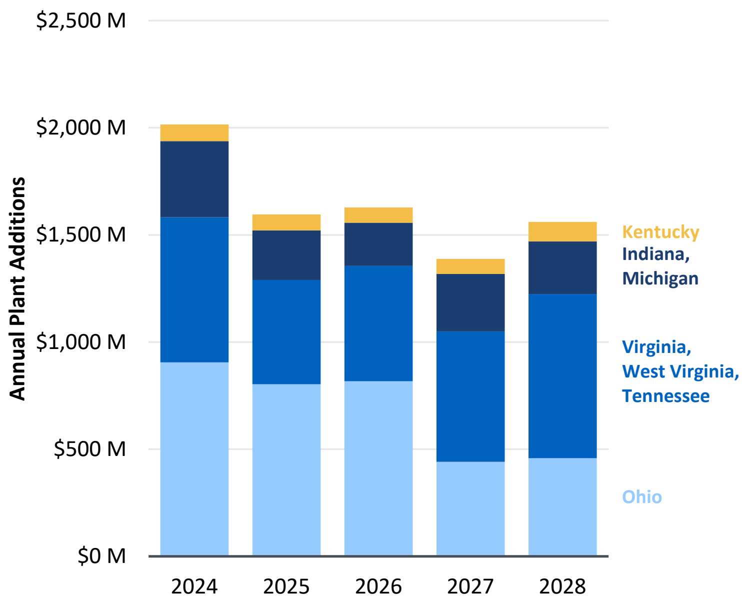
As the increase in transmission investments over the last decade shows, AEP East is currently in the midst of a significant wave of investment driven by the need to refurbish transmission infrastructure and support reliability. As we show in the AEP Report, the current investments wave is a necessary transmission investment cycle driven by high levels of grid investments made during the 1950s and 1960s—a pattern seen across the U.S.[10] Current rules provide AEP East with the obligation to address "asset management" needs within its service territory that are similar to those of other PJM Transmission Owners ("TO").[11] The increasing number of transmission assets reaching their end-of-service life will continue to drive AEP transmission investment needs, including in Kentucky.

Recent testimonies filed by AEP witnesses have highlighted the age of Kentucky's asset fleet and emphasized the need for investments in grid enhancements or expansions to reliability challenges associated with aging transmission facilities. As AEP witnesses have recently explained, "at present, Kentucky Power's average conductor age is roughly 51.1 years of

[10] AEP Report at Section II.C.2.
[11] AEP Report at Section I.B.1.

service. Additionally, over 358 line miles are 60 years of age or older, and of these line miles, over 274 are over 70 years old."[12] Said differently, 274 of 1,263 Kentucky Power's circuit miles, or over 20%, are already beyond their useful life while the system continues to age.[13] This trend supports AEP's forecasts of growing transmission investment needs in Kentucky. As shown in Figure 2, over the course of the current 5-year forecast, projected transmission investment for AEP East are at or above $1.5 billion per year. Kentucky's share of that investment is projected to grow from 2.5% in 2023 to 5.9% by 2028, as summarized in Table 2.

**FIGURE 2: PROJECTED ANNUAL TRANSMISSION ADDITIONS—AEP EAST STATES**




Note: Kingsport Company and Wheeling Power Company, along with West Virginia Transmission Company are included with Appalachian Power Company and Appalachian Transmission Company as part of Virginia, West Virginia, Tennessee. State investment includes Opco and Transco. The company's expectation is that additional transmission investment may be required to meet changing outlooks for load growth, currently driven by proposed new data centers.
Source: AEP Report, Figure 8. Projections as of December 2023.

[12] Direct Testimony of Kamran Ali, KY PSC Case No. 2023-00159 (June 22, 2023) at 6-11:16.

[13] See Direct Testimony of Kamran Ali, KY PSC Case No. 2023-00159 (June 22, 2023) at 3:17, for approximate KP number of circuit miles.

**TABLE 2: STATE SHARES OF PROJECTED ANNUAL TRANSMISSION INVESTMENTS (2024 TO 2028)**

| Year | Virginia, Tennessee, West Virginia | Indiana, Michigan | Kentucky | Ohio |
|---|---|---|---|---|
| **2024** | 33.6% | 17.6% | 3.9% | 44.9% |
| **2025** | 30.5% | 14.5% | 4.6% | 50.4% |
| **2026** | 33.0% | 12.4% | 4.4% | 50.2% |
| **2027** | 43.8% | 19.3% | 5.0% | 31.8% |
| **2028** | 49.1% | 15.7% | 5.9% | 29.4% |

Note: Kingsport Company and Wheeling Power Company, along with West Virginia Transmission Company are included with Appalachian Power Company and Appalachian Transmission Company as part of Virginia, West Virginia, Tennessee. State investment includes Opco and Transco.
Source: AEP Report, Table 2. Projections as of December 2023.

The projected transmission additions for AEP East demonstrate that sustained investments will continue over the next five years. While the overall scale of investment in Kentucky is relatively smaller, projections show an increase in Kentucky Power's share of AEP East's annual investments. Compared with under $35 million of average annual Kentucky transmission investments between 2012 to 2015, and $54 million between 2016 and 2023, the forecast of Kentucky Power's transmission investments exceeds $76 million annually between 2024 and 2028.

## B. Transmission Cost Allocations to Kentucky

AEP East allocates the costs of its transmission investments to its Opcos based on the 12-month average of each Opco's load during AEP East's monthly peak-load hour. This 12 Coincident Peak ("12 CP") method is discussed in further detail in the AEP Report.[14] AEP's transmission cost allocation starts with its transmission revenue requirements and zonal transmission rate for all AEP East companies, then removes the transmission charges collected from unaffiliated transmission customers and apportions the remaining revenue requirements between Kentucky Power and other Opcos based on 12 CP shares. As shown in Figure 3 and Table 3, Kentucky Power's 12 CP share has decreased from 6.5% in 2015 to 5.6% in 2023.

[14] See AEP Report at Section II.C.3, IV.A.1, VI.

**FIGURE 3: HISTORICAL 12 CP SHARE OF KENTUCKY POWER**

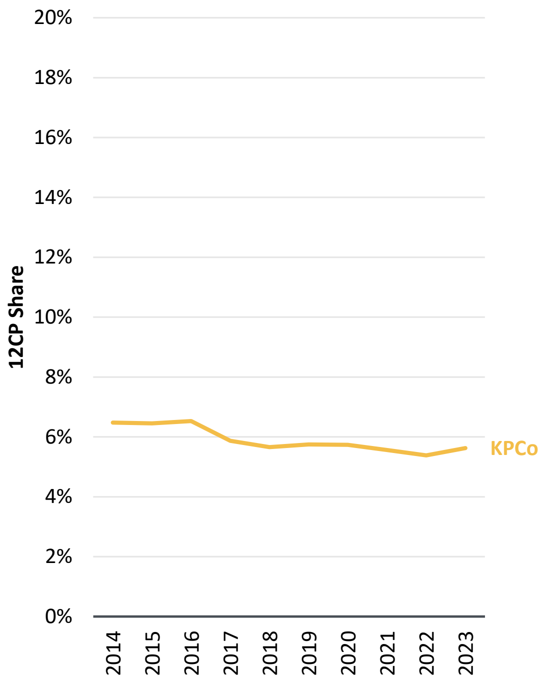



**TABLE 3: HISTORICAL 12 CP SHARES OF AEP-EAST OPERATING COMPANIES**

| Year | APCo | I&M | KPCo | OPCo |
|---|---|---|---|---|
| **2014** | 34.2% | 17.2% | 6.5% | 42.2% |
| **2015** | 34.8% | 17.2% | 6.5% | 41.5% |
| **2016** | 35.6% | 16.9% | 6.5% | 41.0% |
| **2017** | 34.6% | 17.6% | 5.9% | 41.9% |
| **2018** | 34.7% | 17.6% | 5.7% | 42.1% |
| **2019** | 34.2% | 17.6% | 5.7% | 42.4% |
| **2020** | 34.7% | 17.0% | 5.7% | 42.6% |
| **2021** | 34.0% | 17.4% | 5.6% | 43.1% |
| **2022** | 33.8% | 17.4% | 5.4% | 43.4% |
| **2023** | 34.2% | 17.0% | 5.6% | 43.1% |

Note: Appalachian Power includes the loads of Kingsport Power and Wheeling Power.
Source: AEP Report, Figure 10, Table 6.

According to AEP projections, the forecast 12 CP shares of the AEP East Opcos will continue to change slowly over time, reflecting the expected load growth that differs by Opco. As shown in Figure 4 and Table 4 below, Kentucky Power's 12 CP share is anticipated to decline from its current level of 5.6% in 2023 to 5.3% in 2028, despite increasing forecasted investment in the state. At the same time when Kentucky's 12 CP shares are declining, its share of annual transmission investments is more than doubling from 2.5% in 2023 to 5.9% in 2028, as discussed earlier in Table 1 and Table 2.

**FIGURE 4: PROJECTED 12 CP SHARES**

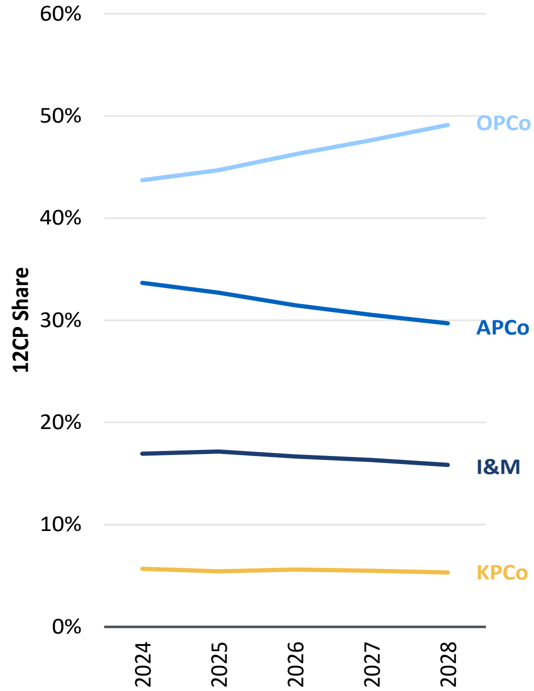



**TABLE 4: PROJECTED 12 CP SHARES**

| Year | APCo | I&M | KPCo | OPCo |
|---|---|---|---|---|
| **2024** | 33.7% | 16.9% | 5.7% | 43.7% |
| **2025** | 32.7% | 17.2% | 5.4% | 44.7% |
| **2026** | 31.5% | 16.7% | 5.6% | 46.2% |
| **2027** | 30.5% | 16.3% | 5.5% | 47.6% |
| **2028** | 29.7% | 15.9% | 5.3% | 49.1% |

Note: 12 CP load shares of Appalachian Power include the loads of Kingsport Power and Wheeling Power.
Source: AEP Report, Figure 11, Table 8. Projections as of November 2023.

## C. Comparing Allocations with the Cost of Kentucky-owned Transmission

As noted earlier, the Commission has raised concerns about the apparent mismatch between historical cost allocations and the levels of investment in each Opco. Table 5 below compares the annual Transmission Revenue Requirement ("TRR") of Opco and Transco transmission facilities in Kentucky and other states with the AEP transmission costs allocated to these states.[15] As shown, the Kentucky share of AEP East's annual TRR has declined from 6.4% in 2015 to 3.9% in 2023. At the same time the 12 CP allocation of AEP East transmission cost has decreased from 6.5% in 2015 to only 5.6% in 2023.

While the 12 CP share allocated to Kentucky Power does in fact currently exceed Kentucky's share of total AEP East transmission investments and associated TRRs, concerns regarding this mismatch require additional context regarding reasonable transmission cost allocation, including how Kentucky uses the AEP East transmission system, as we discuss below.

[15] Further information on development of TRRs is available in the AEP Report at Section III.A.

**TABLE 5: COMPARISON OF OPCO TRR SHARES AND 12 CP COST ALLOCATION SHARES**

| | APCo | | I&M | | KPCo | | OPCo | |
|---|---|---|---|---|---|---|---|---|
| Year | TRR Share | 12CP | TRR Share | 12CP | TRR Share | 12CP | TRR Share | 12CP |
| **2014** | 27.2% | 34.2% | 18.1% | 17.2% | 7.4% | 6.5% | 47.2% | 42.2% |
| **2015** | 26.8% | 34.8% | 18.3% | 17.2% | 6.4% | 6.5% | 48.5% | 41.5% |
| **2016** | 24.3% | 35.6% | 20.1% | 16.9% | 5.5% | 6.5% | 50.0% | 41.0% |
| **2017** | 27.5% | 34.6% | 18.5% | 17.6% | 5.5% | 5.9% | 48.6% | 41.9% |
| **2018** | 26.5% | 34.7% | 20.1% | 17.6% | 5.0% | 5.7% | 48.4% | 42.1% |
| **2019** | 25.6% | 34.2% | 21.2% | 17.6% | 4.7% | 5.7% | 48.5% | 42.4% |
| **2020** | 25.9% | 34.7% | 21.7% | 17.0% | 4.1% | 5.7% | 48.2% | 42.6% |
| **2021** | 25.9% | 34.0% | 23.1% | 17.4% | 4.0% | 5.6% | 46.9% | 43.1% |
| **2022** | 27.0% | 33.8% | 22.5% | 17.4% | 4.0% | 5.4% | 46.5% | 43.4% |
| **2023** | 27.7% | 34.2% | 22.5% | 17.0% | 3.9% | 5.6% | 45.9% | 43.1% |

Note: Plant addition data based on historical FERC Form 1 filings; 12 CP data provided by AEP.
Source: AEP Report, Table 7.

Neither the drivers of nor the benefit from AEP East transmission investment can be reflected by Opco-specific transmission ownerships. Accordingly, utilizing shares of AEP East TRR would not provide a reasonable cost allocation option that would yield costs allocations that are roughly commensurate with benefits received for Kentucky or other AEP East states. Similarly, the widely varying shares of plant additions over time reflect AEP's effort to address system-wide needs as they arise, which is not correlated with how Opcos use the AEP East transmission system and, if used as the basis for cost allocations, would yield more unpredictable variations in the allocations over time.

# D. Kentucky's Use of the AEP Transmission System

## 1. Flow-Based Transmission System Use Analysis

To identify Kentucky's use of the AEP East system, and whether that use supports the difference between investment shares and 12 CP cost assignments, a flow-based usage analysis using a summer peak power-flow case was requested and directed by Brattle and performed by

AEP. This analysis enables identification of the approximate shares of AEP's transmission system use attributable to each Opco from facilities outside its own footprint. By studying the flows on AEP's transmission system attributable to serving each Opco's summer peak load, this analysis roughly estimates usage-based benefits received by each Opco. This analytical proxy provides a useful data point for evaluating whether various potential cost allocation approaches roughly reflect transmission facility use and so that they are roughly commensurate with benefits received. The detailed methodology employed for this analysis is discussed in the AEP Report.[16]

## 2. Opco Flow-based Transmission Use Results

The flow-based usage analysis shows that each AEP East Opco significantly uses facilities that are owned by other AEP East Opcos and Transcos. As shown in Table 6, this flow-based usage analysis estimates that Kentucky Power (as a User Opco) uses 8.9% of AEP's transmission system in Virginia, Tennessee, and West Virginia, 2.8% of Indiana and Michigan's transmission, and 3.3% of AEP's Ohio facilities. Conversely, Appalachian Power, Indiana Michigan, and Ohio Power utilize (as User Opcos) 35.3%, 10.2%, and 18.1% of AEP's Kentucky facilities (as a Host Opco), respectively. [17] These usage-shares demonstrate Kentucky's significant use and resulting benefit from other AEP Opco and Transco systems, with implications for ultimate assignment of transmission costs. As the table shows, while Kentucky accounts for only 36.3% of power flowing on its transmission facilities, it also uses significant shares of the much larger neighboring systems. These results demonstrate the integrated nature of all AEP East Opcos in the AEP East transmission system, which is the basis for the current cost sharing arrangement set out in the AEP Transmission Agreement.[18]

[16] AEP Report, Section V.

[17] We note that the flow-based usage analysis results may change by season within a given year, and over time as the system evolves and new investments are made.

[18] See AEP Report at Section III.A.5.

**TABLE 6: FLOW-BASED TRANSMISSION USE OF OPCO+TRANSCO FACILITIES BY OPCOs**

| | Opco and Transco Owners | | | |
|---|---|---|---|---|
| **User Opcos** | **Virginia, Tennessee, West Virginia** | **Indiana, Michigan** | **Kentucky** | **Ohio** |
| **Appalachian Power Company** | 64.3% | 13.9% | 35.3% | 12.1% |
| **Indiana Michigan Power Company** | 6.0% | 50.6% | 10.2% | 15.3% |
| **Kentucky Power Company** | 8.9% | 2.8% | 36.3% | 3.3% |
| **Ohio Power Company** | 20.8% | 32.8% | 18.1% | 69.3% |
| **Total** | 100% | 100% | 100% | 100% |

Source: Brattle analysis of AEP power flow studies. AEP Report, Table 15.

To determine the appropriate cost share of the contributions resulting from this use of other "host" Opco systems, we assigned to each "user" Opco a percentage share of the host Opco's TRR equal to the user Opco's flow share of the host Opco's facilities as shown in Table 6 above.[19] This approach recognizes the large differences in host Opco revenue requirement, which means that Kentucky's 3.3% use of AEP's Ohio system accounts for a much larger cost share than its 2.8% use of the facilities in Indiana and Michigan.[20] Another way to illustrate this point is in terms of revenue requirement: even though Kentucky Power's percentage use of AEP's Ohio transmission system (3.3%) is much smaller than Ohio Power's percentage use of Kentucky's system (18.1%), Kentucky's $41 million usage share of Ohio system is greater than Ohio Power's $19 million usage share of Kentucky's system—simply because AEP's Ohio transmission system and revenue requirement is so much larger.

Ultimately, each Opco's external and internal TRR usage shares are added to create a proxy for transmission cost sharing that reflects the estimated flow-based utilization of AEP East transmission facilities, as shown in Table 7 below. Compared to both the 12 CP cost allocation shares and Kentucky's ownership share of AEP East's total transmission costs, the result of this illustrative transmission use analysis shows that Kentucky Power's flow-based usage of AEP East transmission facilities would yield a cost allocation of $162 million or 7.0% of AEP East's total TRR. Kentucky's current 12 CP share of 5.6% is much more closely reflective of the flow-based system use calculated than Kentucky's 3.9% share of AEP East's TRR, even when accounting for

[19] See AEP Report at Section V.A. Note this is called the "external share" that each 'user' Opco is calculated as contributing to the 'host' Opcos. The remaining revenue requirement from each Opco, after netting out external contributions from the other three user Opcos, is the 'internal share.'

[20] AEP Report at Section V.

the expected future increase in Kentucky's share of TRR due to the higher shares of Kentucky transmission investments looking forward.

**TABLE 7: CALCULATION OF OPCO FLOW-BASED SHARES OF OPCO+TRANSCO TRRs**

| | | Opco and Transco Owners | | | | | |
|---|---|---|---|---|---|---|---|
| | 2023 TRR ($Million) → | Virginia, Tennessee, West Virginia | Indiana, Michigan | Kentucky | Ohio | Total | |
| **User Opcos** | | $756 | $613 | $106 | $1,254 | $2,729 | As % |
| **Appalachian Power Company** | | $418* | $85 | $37 | $152 | $692 | 29.8% |
| **Indiana Michigan Power Company** | | $46 | $175* | $11 | $191 | $423 | 18.2% |
| **Kentucky Power Company** | | $67 | $17 | $36* | $41 | $162 | 7.0% |
| **Ohio Power Company** | | $157 | $201 | $19 | $667* | $1,044 | 45.0% |
| **Total Opco + Transco TRR Recovered from Affiliates** | | **$687** | **$478** | **$104** | **$1,051** | **$2,320** | **100%** |
| **Opco TRR Recovered from Embedded Non-Affiliates*** | | **$69** | **$135** | **$2** | **$202** | **$408** | |

Note: Reported TRRs (in $ millions) are based on AEP's 2023 FERC Formula Rate, consistent with the 2023 series RTEP case used for the Power Flow analysis. Allocation of Host Opco + Transco TRR to other User Opcos based on percentage of flow-based usage as shown in Table 15 of the AEP Report.
* TRRs reduced by revenues from AEP NITS transmission service charged to its embedded non-affiliated transmission users.
Source: AEP Report, Table 16.

# 3. Implications for Kentucky Transmission Cost Allocation

The identified usage-based cost share of the AEP system attributable to Kentucky is consistent with known uses of the AEP East transmission system for supplying Kentucky Power loads, which relies heavily on importing generation from the rest of the AEP East footprint. It supports the current allocation of AEP transmission costs among Opcos as reasonable and roughly commensurate with usage-based benefits received by the Opcos. Ultimately, this power flow analysis supports AEP's previous testimony which concludes that Kentucky uses more of other Opco's transmission systems than the other Opco's use of Kentucky's system.[21] Although the absolute dollar value of Kentucky's contribution is lower than that of other Opcos (at $124 million, in Table 7), Kentucky Power's calculated usage-based cost share of the other (much larger) neighboring systems as a percentage of its overall revenue requirements is significantly

[21] See Direct Testimony of Joshua Burkholder, KY PSC Case No. 2023-00159 (June 21, 2023) at 10-2:5.

greater than that of the other Opcos, resulting in external usage-based cost shares more than double the amount received from other Opco's use of Kentucky's (much smaller) own system.[22]

In other words, Kentucky Power's higher usage-based cost allocation is consistent with the current understanding of Kentucky's significant reliance on the larger AEP East transmission system. As previously explained by AEP before the Commission, Kentucky Power is a net importer of energy with significant reliance on AEP East and PJM transmission for resource adequacy needs.[23] This is reflected in this illustrative summer-peak-based transmission system usage analysis. Given that Kentucky Power is a winter peaking system while AEP East as a whole can be summer or winter peaking, Kentucky Power's shares may be higher if similar analyses were done for other seasons. Locating additional generation in Kentucky would impact these results, slightly reducing Kentucky's use of the larger AEP East transmission network.

In addition, higher investments are expected in Kentucky Power's territory looking forward, in part to ensure system reliability after Kentucky Power ceases using capacity and energy from the Mitchell Generation facility to serve internal load after 2028.[24] Additional Kentucky imports may be required from within the AEP East system or the broader PJM footprint.[25] Due to its location at the edge of the AEP zone, Kentucky Power does not typically benefit from counterflows like the rest of AEP Opcos. This minimizes the netting effect experienced when identifying the future need for new transmission lines and increases Kentucky Power's relative use of the AEP East transmission system as reflected in the power-flow analysis summarized above and described in more detail in the AEP Report.[26]

# III. Assessment of Alternative Cost Allocation Approaches

There are various potential allocation alternatives to the 12 CP approach currently used to apportion transmission costs of the AEP East system to the Opcos, as explained in the AEP

[22] Compare $124 million Kentucky Power's contribution to other Opcos as compared with $54 million contribution from other Opcos. Note that other Opco's external contribution and contributions from Other Opco's are roughly aligned. For example, Ohio Power's contribution to other Opcos of $336 million is roughly aligned with its $358 million in received contributions from other Opcos.

[23] Direct Testimony of Kamran Ali, KY PSC Case No. 2023-00159 (June 22, 2023) at 7:13-15.

[24] Direct Testimony of Kamran Ali, KY PSC Case No. 2023-00159 (June 22, 2023) at 7:20-22.

[25] Direct Testimony of Kamran Ali, KY PSC Case No. 2023-00159 (June 22, 2023) at 7:16-19.

[26] AEP Report, Section V.

Report.[27] In determining the reasonableness of an allocation method, including whether its allocation results are roughly commensurate with benefits received, it is useful to compare it to a range of alternative approaches. For The AEP Report evaluates six cost allocation approaches and finds that several of the cost allocation methodologies yield similar outcomes, suggesting that a variety of methods offer cost allocations that are roughly commensurate with benefits received. However, when evaluating the various allocation approaches against other rate design principles, the findings of the AEP Report support retaining the status-quo 12 CP allocation method for apportioning AEP East transmission investment costs among Opcos.

Table 8 presents 2023 data for the 12 CP allocation methodology, six alternative allocations approaches, the states' share of AEP's Opco and Transco TRRs, and the usage-based allocations discussed above. Evaluating a range of allocation methodologies provides a useful comparison among the alternatives. The six cost allocation approaches (labeled rows A through F in the table), although relying on widely varying methods of apportioning the cost, result in a relatively narrow range of different allocations to Opcos.

From Kentucky Power's perspective, the range of 2023 estimated TRR shares is within 1% (ranging from 4.9% to 5.6%) across these first six allocation options. It is our assessment that each of these methods are likely to allocate costs in a way that is roughly commensurate with benefits received from associated transmission investments. The final two rows (labeled rows G and H in the table) are provided for comparison purposes. Regarding row G, relying on Opco investments as an allocation metric does not yield allocations that roughly correlate with the use of the system, the benefit received, or the transmission projects caused by an Opco, and therefore should not be relied on as an allocation option.[28] The illustrative flow-based analysis (row H), while a useful indicator of system use and benefits, is not sufficiently developed to implement it directly as a cost allocation methodology.[29]

27 AEP Report, Section IV.

28 AEP Report, Section VI.

29 As noted in the AEP Report, the flow-based transmission use analysis is illustrative as it is based solely on a single summer peak load case and calculates the use of an Opco's and affiliated Transco's facilities as a simple average of the MW-based shares (not cost-weighted shares) across all of the Opco and Transco facilities, irrespective of the size, length, or cost of individual facilities.

**TABLE 8: SUMMARY OF TRANSMISSION COST ALLOCATION RESULTS FOR 2023**

| # | Methodology | Estimated Cost Share (Based on 2023 data) | | | |
|---|---|---|---|---|---|
| | | Appalachian Power Company | Indiana Michigan Power Company | Kentucky Power Company | Ohio Power Company |
| A | 12CP | 34.2% | 17.0% | 5.6% | 43.1% |
| B | 1CP | 30.7% | 17.2% | 5.1% | 46.9% |
| C | NCP | 33.7% | 20.0% | 5.5% | 40.8% |
| D | Energy-Based | 33.1% | 20.6% | 5.0% | 41.3% |
| E | Highway/Byway | 31.3% | 19.1% | 5.1% | 44.5% |
| F | Two-Tier Voltage Split | 30.9% | 19.6% | 4.9% | 44.5% |
| G | Opco + Transco TRR | 27.7% | 22.5% | 3.9% | 45.9% |
| H | Transmission Usage Analysis | 29.8% | 18.2% | 7.0% | 45.0% |

Note: Allocation percentages reflect share of AEP affiliate costs.
Source: AEP Report, Table 17.

When the cost allocation approaches are reviewed against other ratemaking principles, certain options stand out favorably. To do so, we turn to the ratemaking principles outlined in Bonbright's *Principles of Public Utility Rates.*[30] While Bonbright understood that an "ideal" rate was not feasible in practice, he provided several objectives that would lead rate designers toward more "reasonable" and "workable" designs.[31] These objectives include developing rates that are:[32]

- **Stable and Predictable** with a "minimum of unexpected changes seriously adverse to existing customers;"
- **Cost-reflective** so they exhibit "fairness of the specific rates in the apportionment of total costs of service among the different consumers;"
- **Simple** to foster "understandability, public acceptability, and feasibility of application;"
- **Fair** to avoid "undue discrimination in rate relationships;" and
- **Efficient** to "discourag[e] wasteful use of service while promoting all justified types and amounts of use."

[30] Bonbright, J., *Principles of Public Utility Rates* [1st ed.], (Columbia University Press, 1961).

[31] Bonbright, J., *Principles of Public Utility Rates* [1st ed.], (Columbia University Press, 1961) at 35 ("Satisfactory results, not ideal or optimum results, are all that can be expected of the ablest group of ratemakers").

[32] Quotes in this list of bullets from Bonbright, J., *Principles of Public Utility Rates* [1st ed.], (Columbia University Press, 1961) at 291.

For assessing transmission cost allocations, several other objectives should be considered. Namely, the Federal Energy Regulatory Commission ("FERC") and the courts have set out the "cost causation" principle, which in part relies on the identification of transmission users as beneficiaries of transmission investments.[33] As discussed in more detail in the AEP Report, FERC has set out six cost allocation principles, consistent with Bonbright's work and building on court precedent.[34] One of the FERC's key cost allocation principles requires that transmission costs allocated should be "roughly commensurate" with benefits received.[35]

When evaluated against these principles, AEP's current 12 CP allocation methodology offers a number of attractive attributes with a limited number of disadvantages compared to the alternatives evaluated. As shown in Table 9 below, the 12 CP method is more stable and predictable over time, more reflective of the drivers of transmission costs spread across the year, and more reflective of transmission system use compared to the alternatives. Similarly attractive other methodologies include the two voltage-based methodologies (i.e., the Highway-Byway and 2-Tier Voltage-Based approaches), which also feature more stability and predictability over time and correlate more strongly to Opco system use relative to other cost allocation methodologies—although at the expense of a slightly more complex design. Energy-based allocations are simple and easily understood, but less reflective of the underlying drivers and beneficiaries of the AEP East transmission system. As shown in Figure 5 below, compared to the existing 12 CP approach, the allocations based on 1 CP and 1 NCP are less stable and predictable by relying on a single hour's load in each year—particularly the 1 CP option, which additionally creates uncertainty because, while Kentucky Power tends to be winter peaking, AEP East peak loads can occur during either the winter or summer season of the year, which heavily influences cost allocation.

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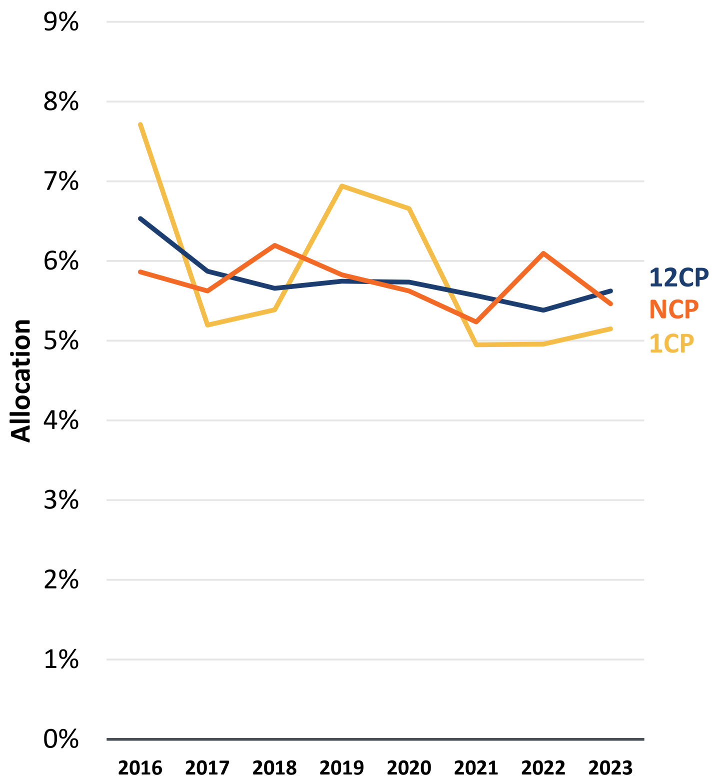
33 See *Illinois Commerce Commission v. FERC*, 576 F.3d 470 at 476 (7th Cir. 2009) ("FERC is not authorized to approve a pricing scheme that requires a group of utilities to pay for facilities from which its members derive no benefits, or benefits that are trivial in relation to the costs sought to be shifted to its members … To the extent that a utility benefits from the costs of new facilities, it may be said to have "caused" a part of those costs to be incurred, as without the expectation of its contributions the facilities might not have been built, or might have been delayed); *Midwest ISO Transmission Owners v. FERC*, 373 F.3d 1361, 1368 (D.C. Cir. 2004)("[W]e evaluate compliance with this unremarkable principle by comparing the costs assessed against a party to the burdens imposed or benefits drawn by that party").

34 AEP Report, Section I.B.4.

35 *El Paso Elec. Co. v. FERC*, 832 F.3d 500 (5th Cir. 2016) ("A free rider is an entity that is subsidized by other entities because it refuses to invest in transmission development, allows other entities to pay for that development, and reaps the benefits").

**FIGURE 5: COMPARISON OF 1 CP AND 12 CP ALLOCATION OPTIONS FOR KENTUCKY OPCO**




Note: NCP shares are calculated by dividing an operating company's maximum demand during the year by the sum across all AEP Opcos' (not coincidental) maximum demands over the same year.
Source: AEP Report, Table 6, Table 10, and Table 11.

In addition, the 1 CP Option offers less cost-reflective, fair, and efficient rates because the allocation approach is not well-aligned with the drivers of AEP transmission investments in the PJM footprint. More detailed analyses of each of these rate design options are provided in the AEP Report.[36] Compared to these alternatives, AEP's current 12 CP methodology stands out favorably across most of the ratemaking principles evaluated.

[36] AEP Report, Section IV.A.

TABLE 9: EVALUATION OF ALTERNATIVE TRANSMISSION COST ALLOCATIONS FOR AEP EAST

| RATEMAKING PRINCIPLES | ALLOCATION METHOD | | | | | |
|---|---|---|---|---|---|---|
| | 12 CP | 1 CP | 1 NCP | Energy Based | Highway-Byway | 2-Tier Volt. Split |
| Stable and Predictable | ★★★ | ★ | ★★ | ★★★ | ★★★ | ★★★ |
| Cost-Reflective | ★★★★ | ★ | ★★ | ★★ | ★★★ | ★★ |
| Simple | ★★★ | ★★★ | ★★★★ | ★★★★ | ★★ | ★★★ |
| Fair | ★★★★ | ★ | ★★ | ★★ | ★★★ | ★★ |
| Efficient | ★★★ | ★ | ★★ | ★★ | ★★★ | ★★ |

Source: AEP Report, Table 18.

# IV. Limitations on Restructuring Kentucky Power as a New Zone within PJM

As noted, commenters before the Commission suggested that Kentucky Power could become its own PJM transmission zone.[37] This report identifies several practical, legal, procedural, and technical obstacles to this potential approach. Additional and significant uncertainties would need to be resolved prior to Kentucky Power joining another PJM Transmission Zone, such as East Kentucky Power Cooperative ("EKPC"). Additionally, if Kentucky Power were its own PJM zone, it would likely see increased PJM cost allocations and face higher resource adequacy costs by losing important benefits currently enjoyed by being part of the larger, more diverse AEP East system.

## A. The AEP Transmission Agreement

The AEP Transmission Agreement ("TA") is the foundational agreement between AEP affiliate Opcos with the goal of achieving "the full benefits and advantages available through the coordinated operation of their electric power supply facilities."[38] The TA includes an agreement

[37] Kentucky Public Service Commission, Order, Case No. 2020-00174 (January 13, 2021) at 59.

[38] See AEP Transmission Agreement at § 0.3 (August 4, 2010).

between Opcos setting out the allocation of all costs incurred by AEP in its role as a PJM Load Serving Entity ("LSE").[39] Notably, this agreement sets out processes to recover all transmission costs, including both Network Integration Transmission Service ("NITS") charges developed through AEP's formula rate process and the Transmission Enhancement Charges ("TECs") assigned by PJM for regional projects allocated through Schedule 12 of the PJM Tariff.[40] Both of these charges are recovered through the 12 CP method described above.[41] The TA provides separate provisions for the allocations of revenues between Opcos.[42] Other provisions of the TA are more fully described in the AEP Report at Sections I.B.1 and III.A.5.The Opcos reserve their FPA section 205 filing rights with respect to terms of service that may impact the AEP TA.[43] Any effort by an Opco to leave or modify the TA to facilitate joining another zone or creating a new zone would need to be approved by the FERC. In addition, if the departing Opco were to remain in the AEP Zone, the Opco would be subjected to the significant year-to-year volatility of 1 CP cost allocation for transmission customers which are not parties to the AEP TA inside the AEP Zone.

In addition to the AEP TA implications, Kentucky Power's participation within PJM as a new zone or attempts to join an existing zone would trigger the provisions set out under PJM's Consolidated Transmission Owners Agreement ("CTOA") as discussed further below.

## B. The PJM Consolidated Transmission Owners Agreement

Additional limitations under the PJM CTOA would also need to be overcome to create a standalone Kentucky Power PJM transmission zone. Notably, the CTOA specifically limits the creation of new zones within the boundaries of any existing PJM TO zone.[44] This provision would prohibit Kentucky Power from creating its own transmission zone within PJM. This provision may only be revised subject to the super-majority voting procedures of the CTOA described further within the AEP Report and subsequent FERC approval,[45] or through FERC finding the existing language unjust and unreasonable (likely through the filing of a complaint).

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[39] AEP Report, Section III.A.5.

[40] Including AEP's share of AEP's regional projects (constructed by the transmission companies or the operating companies), and AEP's share of other PJM TO's projects, as set out in the AEP Report at Figure 9.

[41] AEP Report, Section III.A.5.

[42] AEP Transmission Agreement at Appendix 1 (August 4, 2010).

[43] CTOA § 7.4.

[44] CTOA § 7.4.

[45] AEP Report, Section I.B.1.

As identified in previous testimony before the Kentucky Commission, once any change to the CTOA is approved, additional and significant questions would have to be addressed related to the implementation of a standalone zone including "planning, operations, and market impacts of such a change."[46]

## C. Technical Challenges

In addition to the administrative challenges associated with current provisions of the CTOA, several additional factors support Opcos remaining within the AEP zone. Creation of a standalone Kentucky Power zone would result in the smallest zone currently in PJM, with a peak load of "approximately 1,200 MW with the next smallest of the utility load serving zones being EKPC at approximately 2,400 MW."[47] This standalone zone would not contain much internal generation, creating additional resource adequacy and system planning impacts challenging the deliverability of sufficient generation to serve the new zone.[48] To evaluate these needs, PJM would evaluate the Capacity Emergency Transfer Objective ("CETO") of the potential new zone (i.e., the amount of resources outside of the new zone that must be available to serve load from a resource adequacy[49] perspective) and may initiate additional transmission projects to ensure reliability of the newly created zone.[50]

The benefit of partaking in AEP's resource adequacy margin through PJM's processes also extends to participation in the Fixed Resource Requirement ("FRR") alternative. Participation in FRR requires a zone to be able to "demonstrate[] the capability to satisfy the Unforced Capacity obligation for all load in an FRR Service Area, including all expected load growth in such area, for the term of such Party's participation in the FRR Alternative,"[51] a standard that a standalone Kentucky Power zone may struggle to achieve. It is unclear the administrative steps PJM would take related to the FRR should Kentucky Power seek to pursue the necessary rule changes

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[46] Direct Testimony of Steve Herling, KY PSC Case No. 2021-00481 (March 17, 2022) at 12:10-16.

[47] Direct Testimony of Steve Herling, KY PSC Case No. 2021-00481 (March 17, 2022) at 7:17–18.

[48] Direct Testimony of Steve Herling, KY PSC Case No. 2021-00481 (March 17, 2022) at 7:21–8:2.

[49] See PJM Manual 18 at § 2.2 ("Load Deliverability in the Reliability Pricing Model").

[50] Direct Testimony of Steve Herling, KY PSC Case No. 2021-00481 (March 17, 2022) at 8:6-11. Note that in addition to the CETO, PJM would also evaluate the Capacity Emergency Transfer Limit ("CETL") (i.e., the amount of zone-external energy that can be imported over the transmission system during specified emergency conditions) of the new, smaller zone. If the CETL/CETO balance were found to be insufficient, PJM would initiate transmission upgrades to ensure the newly created zone is resource adequate.

[51] PJM Reliability Assurance Agreement Schedule 8.1-B.

described above.[52] From a market perspective, a standalone zone could limit import capability, leading to a higher internal resource requirement, and greater price separation for a Kentucky Power standalone zone.[53]

Further, the potential negative cost implications would extend to Kentucky's cost allocation of PJM regional projects for two reasons. First, today's zone structure enables AEP-internal generation to reduce PJM cost allocations of regionally cost-shared projects. This is because PJM's "solution-based DFAX" methodology must determine geographic locations of generators assumed to serve system loads, with the locations of the selected generators materially impacting the observed use (and allocated cost) of each evaluated transmission facility. Given AEP's robust level of internal generation as compared to its load, PJM's solution-based DFAX analysis sources significant generation from AEP, which accordingly lowers the need for AEP load to rely on regional facilities in the model, reducing PJM's calculated cost assignments to the AEP zone.  A much smaller Kentucky standalone zone would be subject to its own generation dispatch in PJM's analysis, which would likely mean that Kentucky would see its contribution to regionally cost-shared projects increase materially.

Second, the solution-based DFAX analysis enables PJM zones to take advantage of the "netting" benefits of offsetting power flows in the resulting simulation. Due to the geographically dispersed footprint of the AEP zone, AEP and the member Opcos significantly benefit from these netting procedures. Further, when the calculated flows are measured to be beneath a certain threshold, the transmission zone receives no cost allocation under the *de minimis* threshold, as described more fully in the AEP Report.[54] A much smaller Kentucky transmission zone would therefore not enjoy the same degree of benefit from the netting and *de minimus* threshold, resulting in materially larger contributions to the cost of regional facilities. Each of these factors would likely increase customer costs in Kentucky should Kentucky Power be able to become a standalone PJM transmission zone. We have not attempted to assess the exact amount of increased costs, which would be based on detailed future PJM analyses. However, considering the administrative challenges and the likelihood of increased PJM cost allocations, we do not recommend seeking to create a standalone PJM transmission zone for Kentucky Power.

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[52] PJM's definition of a "State Regulatory Structural Change" focuses on the expansion or reduction of retail choice programs, and not the reformation of transmission zones. See Reliability Assurance Agreement Schedule 8.1-C.3.

[53] See e.g., Direct Testimony of Steve Herling, KY PSC Case No. 2021-00481 (March 17, 2022) at 9:4-6.

[54] AEP Report, Section III.A.2.

## D. East Kentucky Power Cooperative

Another potential reform option commenters have raised is the potential for Kentucky Power to join the EKPC PJM transmission zone. The current form of CTOA prevents the AEP zone from shrinking so that an Opco could either create a standalone zone as described above or join another zone, such as an existing, neighboring zone. The current CTOA also provides that Kentucky Power would not be able to be a sub-zone of EKPC,[55] which might require full integration depending on PJM's interpretation of the CTOA. This introduces significant uncertainty and litigation risk related to the CTOA provisions that currently would not permit Kentucky Power to join the EKPC zone. We do not anticipate these risks to be materially different regardless of the corporate transaction structure underlying Kentucky Power's integration into EKPC.

In addition, further provisions would need to be developed by the remaining AEP Opcos and PJM to assign any costs associated with facilities owned by the Kentucky Transco to the new EKPC zone. Kentucky Power would also shoulder part of the EKPC-assigned PJM Tariff charges under Schedule 12. For such regionally cost-shared PJM projects, it is further likely that the cost shares faced by Kentucky Power within EKPC would increase as compared to Kentucky Power within AEP, due to the loss of the significant netting and *de minimis* benefits associated with PJM's DFAX cost allocations to the large AEP East footprint as discussed above, and perhaps due to the fact that both EKPC and Kentucky Power are winter peaking systems.

In addition, Kentucky Power would be responsible on its own (or through sharing with EKPC) for the cost of its asset management and local transmission needs to maintain reliable service as its facilities continue to reach the end of their useful service life (which, as indicated in earlier sections of this report, is increasing). In other words, Kentucky would lose the benefit of sharing these costs across the AEP East footprint, under which Kentucky Power currently is responsible for only 5.6%. Being part of the EKPC zone would likely require Kentucky Power to additionally shoulder a share of the cost of EKPC transmission facilities under a future agreement similar to the AEP TA that would need to be developed and negotiated with EKPC.

[55] CTOA § 7.4 ("transmission rate Zones smaller than those shown in Attachment J to the PJM Tariff, or subzones of those Zones, shall not be permitted within the current boundaries of the PJM Region").

# List of Acronyms

| | |
|---|---|
| AEP | American Electric Power |
| CETL | Capacity Emergency Transfer Limit |
| CETO | Capacity Emergency Transfer Objective |
| CP | Coincident Peak |
| CTOA | Consolidated Transmission Owners Agreement |
| EKPC | East Kentucky Power Cooperative |
| FERC | Federal Energy Regulatory Commission |
| FRR | Fixed Resource Requirement |
| ISO | Independent System Operator |
| LSE | Load Serving Entity |
| NITS | Network Integration Transmission Service |
| Opco | Operating Company |
| PJM | PJM Interconnection Inc. |
| TA | Transmission Agreement |
| TEC | Transmission Enhancement Charge |
| TO | Transmission Owners |
| Transco | Transmission Company |
| TRR | Transmission Revenue Requirement |

# Attachments

## Transmission Cost Allocations Among AEP-East Operating Companies (June 2024)

# VERIFICATION

The undersigned, Lerah M. Kahn, being duly sworn, deposes and says she is the Manager of Regulatory Services for Kentucky Power, that she has personal knowledge of the matters set forth in the foregoing testimony and the information contained therein is true and correct to the best of her information, knowledge, and belief after reasonable inquiry.

Lerah Kahn

Lerah M. Kahn

| | | |
|---|---|---|
| Commonwealth of Kentucky | ) | |
| | ) | Case No. 2025-00338 |
| County of Boyd | ) | |

Subscribed and sworn to before me, a Notary Public in and before said County and State, by Lerah M. Kahn, on January 20, 2026.

Marilyn Michelle Caldwell

Notary Public

MARILYN MICHELLE CALDWELL
Notary Public
Commonwealth of Kentucky
Commission Number KYNP71841
My Commission Expires May 5, 2027

My Commission Expires May 5, 2027

Notary ID Number KYNP71841