UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Kentucky Public Service Commission, Attorney General of the Commonwealth of Kentucky	)	
Complainants	)	
v.	)	Docket No. EL25-___-000
American Electric Power Service Corporation, Appalachian Power Company, Columbus Southern Power Company, Indiana Michigan Power Company, Kentucky Power Company, Kingsport Power Company, Ohio Power Company, and Wheeling Power Company	)	
Respondents		

COMPLAINT OF KENTUCKY PUBLIC SERVICE COMMISSION AND THE ATTORNEY GENERAL OF THE COMMONWEALTH OF KENTUCKY AGAINST THE TRANSMISSION AGREEMENT AMONG RESPONDENTS REGARDING THE ALLOCATION OF COSTS FOR SELF-PLANNED TRANSMISSION DEVELOPMENT

Pursuant to Sections 206, 306, and 309 of the Federal Power Act ("FPA")[1] and Rule 206 of the Rules of Practice and Procedure of the Federal Energy

[1] 16 U.S.C. §§ 824e, 825e, and 825h.

Regulatory Commission ("FERC" or the "Commission"),[2] the Kentucky Public Service Commission ("Kentucky PSC") and the Attorney General of the Commonwealth of Kentucky ("Attorney General"; together "Complainants") submit this Complaint demonstrating that the Transmission Agreement[3] by and among the Respondents, American Electric Power Service Corporation ("AEP"), Appalachian Power Company, Columbus Southern Power Company, Indiana Michigan Power Company, Kentucky Power Company ("Kentucky Power"), Kingsport Power Company, Ohio Power Company, and Wheeling Power Company (collectively the "AEP Retail Companies") is unjust, unreasonable, unduly discriminatory or preferential in the manner it allocates costs to Kentucky Power, thus harming Kentucky consumers. As discussed more fully below, this Complaint challenges only the manner in which the Transmission Agreement allocates the costs for transmission projects self-planned by AEP. As demonstrated in the Complaint and accompanying testimony, AEP self-planned transmission projects outside of the Kentucky Power service territory cannot be shown to be sufficiently connected to serving Kentucky Power customers to allocate costs for far-flung transmission projects geared to serve the customers of other AEP retail distribution companies.

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2 18 C.F.R. § 385.206.

3 *See American Elec. Power Serv. Corp.*, 28 FERC ¶ 61,228 (1984).

I. EXECUTIVE SUMMARY

The Kentucky PSC is charged by statute with fostering the provision of safe and reliable service at reasonable prices to the retail customers of utilities subject to Kentucky PSC's jurisdiction.[4] The approximately 164,000 customers of Kentucky Power Company ("Kentucky Power"), an American Electric Power Company retail operating company, are among those relying on the Kentucky PSC for reasonable electric prices. The Kentucky PSC acting alone in this context, with the central issue outside of its purview, cannot ensure just, reasonable, not unduly discriminatory, or non-preferential rates to Kentucky electricity consumers as certain of the costs impacting Kentucky consumers arise through rates within the exclusive jurisdiction of the Commission. The Attorney General is charged with representing and advocating on behalf of Kentucky consumers before not only the Kentucky PSC but also other state and federal regulatory agencies.[5] The Attorney General cannot protect Kentucky consumers at the Kentucky PSC when the rates at issue are exclusively Commission jurisdictional. Accordingly, FERC must take action as sought in this Complaint to ensure that Kentucky consumers are protected from transmission rates that are unjust, unreasonable, unduly discriminatory or preferential.

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4 *See generally* Kentucky Revised Statutes ("KRS") Chapter 278.

5 KRS 367.150(8).

The allocation of FERC jurisdictional transmission rates to Kentucky consumers for the transmission additions of other AEP Retail Companies and AEP Transcos[6] is addressed in the Transmission Agreement. As described herein, the Transmission Agreement provides for a load ratio share allocation across the entire AEP East seven-state zone ("AEP Zone") for all AEP self-planned transmission projects regardless of the identified planning need for the project. The Transmission Agreement's allocation for AEP's self-planned transmission is unjust, unreasonable, preferential or unduly discriminatory under Section 206 of the Federal Power Act[7] and must be revised.

AEP has retail electric customers in seven states within the PJM Interconnection, L.L.C. ("PJM") region. Since joining PJM, AEP has had a single pricing zone covering its seven-state area, stretching from Michigan to Tennessee.[8] Billions of dollars of transmission ratebase additions have been self-planned by

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6 AEP Appalachian Transmission Company, Inc., AEP Indiana Michigan Transmission Company, Inc., AEP Kentucky Transmission Company, Inc., AEP Ohio Transmission Company, Inc., and AEP West Virginia Transmission Company, Inc. (generally referred to as the AEP Transcos, and collectively with the AEP Retail Companies, "AEP East").

7 16 U.S.C. § 824e.

8 The PJM transmission owners agreed among themselves to prohibit a smaller zone than the AEP Zone existing at the time of integration. *See* Consolidated Transmission Owner Agreement Rate Schedule No. 42, Section 7.4; PJM Open Access Transmission Tariff ("OATT"), Attachment J.

AEP, either as "Supplemental Projects"[9] or under PJM's Attachment M-3[10] within the AEP Zone and allocated to Kentucky retail customers through the Transmission Agreement. Those self-planned AEP projects directly impact Kentucky ratepayers because Attachment M-3 Projects are allocated solely to the transmission zone of the entity planning the transmission, i.e., AEP's seven-state zone. Thus, notwithstanding that Attachment M-3 Projects are supposed to address "local" transmission needs, Kentucky Power is allocated costs for projects hundreds of miles away that arise through the need to serve retail customers in other AEP retail jurisdictions.[11]

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[9] Supplemental Projects are defined in the Amended and Restated Operating Agreement of PJM ("Operating Agreement") as

> a transmission expansion or enhancement that is not required for compliance with the following PJM criteria: system reliability, operational performance or economic criteria, pursuant to a determination by the Office of the Interconnection and is not a state public policy project pursuant to Operating Agreement, Schedule 6, section 1.5.9(a)(ii). Any system upgrades required to maintain the reliability of the system that are driven by a Supplemental Project are considered part of that Supplemental Project and are the responsibility of the entity sponsoring that Supplemental Project.

[10] Attachment M-3 of the PJM OATT sets forth the procedures that PJM transmission owners follow when planning "Asset Management Projects;" Supplemental Projects, and certain other projects described in Attachment M-3 Section (a).

[11] *See infra* pp 13-39.

Given the myriad changes in both AEP's transmission and generation system and the electric grid generally in the 40 years since the Transmission Agreement was entered into, it is no longer the case that AEP self-planned transmission projects outside Kentucky Power's service territory are sufficiently focused on serving Kentucky customers for those Kentucky customers to be allocated costs through the Transmission Agreement as projects needed to serve Kentucky consumers. Nor do the projects benefit those Kentucky consumers in a manner commensurate with the costs allocated to Kentucky Power because, as a result of the required single zone allocation, other similarly situated PJM users of AEP's transmission system are not allocated costs based on benefits received. Yet, as described in this Complaint, through the Transmission Agreement, Kentuckians have been, and will continue to be, allocated millions of dollars in excess transmission rates for projects built to serve the needs of AEP's retail consumers in other states.

When AEP self-plans a transmission project in Kentucky, the Kentucky PSC has the ability to review the proposed transmission project to ensure that the proposed project cost-effectively meets the transmission needs to serve Kentucky consumers before the transmission project is approved for siting.[12] When, however, AEP plans such projects to address the localized needs of electric customers in

[12] *See* KRS 278.020(2).

AEP's other retail states within its multi-state PJM pricing zone, the Kentucky PSC has no effective mechanism to ensure that the projects are needed to serve Kentuckians, or that the projects provide benefits commensurate with the costs allocated when benefits of all system users are measured. More importantly the Kentucky PSC has NO ability to reject an AEP local transmission project outside Kentucky that fails to meet either of those two tests. Further, as reflected in the Complaint filed by the Office of the Ohio Consumers' Counsel, to the extent AEP's self-planned projects are in Ohio, many of those projects and their FERC jurisdictional transmission rates are not reviewed by any regulatory body.[13] Perversely, any denial of an AEP self-planned project in Kentucky by the Kentucky PSC, would only worsen the status quo for Kentucky consumers since the impetus for AEP to build self-planned projects would continue to shift to other states in the AEP Zone without the same level of regulatory oversight.

Through the means available to it as a retail regulator, the Kentucky PSC has sought to engage AEP in voluntarily reforming the costs allocated to Kentuckians as

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13 *The Office of the Ohio Consumers' Counsel v. PJM Interconnection, L.L.C., et al.*, Complaint of the Office of the Ohio Consumers' Counsel to Protect Ohio Consumers under the PJM Tariff from the Failures of Multiple Agencies to Regulate Hundreds of Millions of Dollars in Monopoly Electric Transmission Charges for "Supplemental Projects" Planned by AEP, AES, Duke, and FirstEnergy and Request for Fast-Track Processing at 3, filed September 28, 2023 in Docket No. EL23-105-000 ("OCC Complaint").

a result of AEP's self-planned projects built to support retail consumers in jurisdictions other than Kentucky.[14] A recent proposed sale of Kentucky Power by AEP to Liberty Utilities was conditionally approved by the Kentucky PSC, in part based upon required mitigation of AEP's underinvestment in the Kentucky Power service territory while investing significantly in transmission facilities related to other retail distribution service territories.[15] That transaction was later rejected by FERC, which cited to the Applicants' failure to demonstrate that the proposed

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[14] *See, e.g.*, Kentucky Public Service Commission, Order, Case No. 2020-00174 (January 13, 2021), available at https://psc.ky.gov/pscscf/2020%20Cases/2020-00174/20210113_PSC_ORDER.pdf (last accessed March 12, 2025); Kentucky Public Service Commission, Order, Case No. 2023-00159 (January 19, 2024), available at https://psc.ky.gov/pscscf/2023%20Cases/2023-00159/20240119_PSC_ORDER.pdf (last accessed March 12, 2025).

[15] Kentucky Public Service Commission, Order, Case No. 2021-00481 (May 4, 2022), available at https://psc.ky.gov/pscscf/2021%20Cases/2021-00481/20220504_PSC_ORDER.pdf (last accessed March 12, 2025)("… there is substantial evidence of record, including AEP's admission, that Kentucky Power ratepayers have paid more in transmission costs through the allocation than ratepayers would have paid for only Kentucky Power's transmission investment … [a]s far back as 2018 this Commission noted that Kentucky Power's and AEP's interests are not aligned when it comes to transmission investment and its costs recovery and allocation … [t]he substantial evidence of record also reflects that AEP underinvested in Kentucky Power's distribution system. Liberty's own due diligence discussed that … system investment was beneath industry standards) at 50–51.

transaction would not have an adverse effect on rates.[16] The Kentucky PSC's efforts to engage AEP have not been fruitful, in large part because the rates at issue are FERC jurisdictional transmission rates and the Kentucky PSC thus has limited effective leverage to encourage AEP to treat Kentucky consumers fairly in the planning of transmission projects outside of Kentucky, or in encouraging appropriate allocation of costs for such projects. Even if other states in the AEP Zone wished to pursue a solution along with the Complainants and AEP, the rates at issue remain in a FERC tariff, and so the remedy must be determined by the Commission.

As demonstrated below, the allocation of costs to Kentucky electric consumers through the Transmission Agreement for AEP self-planned transmission in AEP's retail service territories outside of Kentucky is unjust, unreasonable, preferential or unduly discriminatory under Sections 206, 306, and 309 of the Federal Power Act. FERC is obligated under Section 206 to address the unjust, unreasonable, preferential, or discriminatory rates. Although the Commission has the responsibility to establish the replacement rate, Section 206 requires that a Complainant propose a replacement rate to the Commission.[17] The Complainants

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[16] *Liberty Utils. Co.*, Order, 181 FERC ¶ 61,212 (2022) (Following the Commission's Order Denying the Application in EC22-26-000, the Applicants refiled in EC23-56-000, but then later withdrew the new Application prior to the Commission issuing a ruling).

[17] *FirstEnergy Serv. Co. v. FERC*, 758 F.3d 346, 353 (D.C. Cir. 2014) *quoting Md. Pub. Serv. Comm'n v. FERC*, 632 F.3d 1283, 1285 n. 1 (D.C. Cir.2011).

believe that the appropriate mechanism to address the unjust rates is to require amendment of the AEP Transmission Agreement to ensure that the costs for self-planned transmission projects remain exclusively in the retail distribution service territory causing the need for the project, absent an AEP filing with the Commission to establish, on an individual project specific basis, that a broader allocation is appropriate.

II. PARTIES

A. Complainants Kentucky PSC and the Attorney General of the Commonwealth of Kentucky

The Kentucky PSC is a three-member administrative body with quasi-legislative and quasi-judicial duties and powers.[18] The Kentucky PSC was created in 1934 by the Kentucky General Assembly and currently regulates the intrastate rates and services of investor-owned electric, natural gas, telephone, water and sewage utilities, customer-owned electric and telephone cooperatives, water districts and associations, and certain aspects of gas pipelines.[19]

In 2002 the Kentucky General Assembly created the Kentucky State Board on Electric Generation and Transmission Siting.[20] The Board considers requests

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18 *See* KRS Chapter 278 *supra*.

19 *Id*.

20 *See* KRS 278.700–718; *see also* Kentucky PSC About Page, History, https://psc.ky.gov/Home/About#AbtComm (last accessed March 12, 2025).

for the construction of non-jurisdictional (merchant) power plants and transmission lines, and all three Kentucky PSC commissioners are *ex officio* members of the Board. In 2004 legislation placed under Kentucky PSC jurisdiction the construction of any electric transmission lines of more than 138 kilovolts and more than a mile in length.[21]

The Attorney General of the Commonwealth of Kentucky, by and through his Office of Rate Intervention, pursuant to Kentucky Revised Statutes 367.150(8), is given the right and obligation to appear before local, state, and federal regulatory agencies to represent Kentucky consumers' interests.

B. Respondents

American Electric Power is a multi-state utility holding company, coordinated through respondent American Electric Power Service Corporation. AEP has multiple retail distribution service territories in PJM and transmission owning entities without direct retail service obligations. The AEP entities in PJM include Appalachian Power Company, Indiana Michigan Power Company, Kentucky Power Company, Kingsport Power Company, Ohio Power Company, Wheeling Power Company, AEP Appalachian Transmission Company, Inc., AEP Indiana Michigan Transmission Company, Inc., AEP Kentucky Transmission Company, Inc., AEP Ohio Transmission Company, Inc., and AEP West Virginia

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21 *Id*.

Transmission Company, Inc. (generally referred to as the AEP Transcos and collectively with the AEP Retail Companies, "AEP East").

The AEP Retail Companies are members of a Transmission Agreement that allocates transmission-related costs and revenues among the AEP Retail Companies. The Transmission Agreement, originally entered into in 1984, remained in place as the AEP companies transitioned certain transmission facilities to PJM's operational control.[22] In 2009, a settlement was entered into in which the settling parties agreed to a revised allocation of transmission costs among the AEP companies and transmission customers.[23] With certain minor modifications that Transmission Agreement remains in effect today.

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22 *See New PJM Companies, et al.*, 105 FERC ¶ 61,251 at P 107 (2003).

23 *See American Elec. Power Serv. Corp.*, 133 FERC ¶ 61,112 (2010) (letter order).

III. COMMUNICATIONS

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IV. AEP'S ZONAL ALLOCATION AMONG RETAIL OPERATING COMPANIES FOR 'LOCAL' TRANSMISSION PROJECTS IS UNJUST, UNREASONABLE, UNDULY DISCRIMINATORY OR PREFERENTIAL UNDER SECTION 206 OF THE FEDERAL POWER ACT

The AEP Retail Companies and AEP Transcos are part of the AEP Zone in PJM and, therefore, the costs of owning and operating their respective transmission facilities are combined into a single zonal rate for transmission service. Pursuant to the Consolidated Transmission Owners Agreement ("CTOA") among PJM and its transmission owners,[24] the AEP seven-state Zone cannot be divided up among retail operating companies or otherwise absent new parties joining PJM.[25] Obviously if Kentucky Power were its own zone, this issue would not arise but because the CTOA prohibits Kentucky Power from moving to a smaller zone, the only appropriate avenue to achieve the needed rate relief is through the Complaint challenging the allocation among AEP Retail Companies within the Transmission Agreement.

PJM determines the AEP zonal transmission rate by adding the AEP Zonal charges from PJM together with the annual transmission revenue requirements of the AEP Retail Companies and AEP Transcos calculated consistent with the AEP Retail Companies' transmission formula rate found in PJM Open Access Transmission Tariff ("OATT") Attachment H-14 and the AEP Transcos' transmission formula rate found in Attachment H-20.[26] The formula rates for the AEP Retail Companies and Transcos include their investment in the ballooning Attachment M-

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24 https://www.pjm.com/-/media/DotCom/documents/agreements/toa.ashx (last accessed March 12, 2025).

25 *See* Article 7.4 of the CTOA, providing: **Transmission Rate Zone Size**. For purposes of developing rates for service under the PJM Tariff, transmission rate Zones smaller than those shown in Attachment J to the PJM Tariff, or subzones of those Zones, shall not be permitted within the current boundaries of the PJM Region; provided, however, that additional Zones may be established if the current boundaries of the PJM Region is expanded to accommodate new Parties to this Agreement.

26 Attachment H-14 is the formula rate for the AEP Retail Companies and Attachment H-20 is the formula rate for the AEP East Transmission Companies.

3 Project category. PJM charges transmission customers within the AEP Zone the AEP zonal transmission rate.

Since 2019 AEP entities have added $3.4 billion in self-planned transmission to the AEP ratebase in PJM. In that period, more than $75 million has been allocated to Kentucky electricity consumers, yet few, if any, of the self-planned projects have any relationship to serving Kentucky Power retail or wholesale customers. Instead, as discussed below, and in the Affidavit of Rao Konidena, AEP's own statements make it clear that those projects are needed to support retail electricity customers in AEP's various retail distribution service territories in states other than Kentucky. It is unjust, unreasonable, preferential or unduly discriminatory to allocate costs to electricity consumers in Kentucky for AEP self-planned transmission outside of Kentucky without a definitive showing that such projects were specifically required to serve Kentucky customers.

A. History of AEP's Existing Zonal Allocation

1. Initial Transmission Agreement

As noted above, in 1984 the AEP Retail Companies entered into a Transmission Agreement.[27] At the time of that agreement, AEP East planned the generation needs of its retail operating companies on a holistic basis and delivered that generation through an Interconnection Agreement among those AEP Retail

[27] *See supra* note 3.

Companies. Until the Transmission Agreement, notwithstanding that generation was planned on a holistic basis for AEP Retail Companies, transmission, regardless of how it was planned, was developed and owned within individual retail operating companies with the cost allocated solely to the operating company in which the transmission was built.[28] However, industry changes in the 1970s resulted in a significant imbalance of transmission costs as a result of the investment in new 345 kV and 765 kV transmission facilities, with some AEP Operating Companies investing more in transmission facilities than the other AEP Operating Companies relative to their use of the AEP system.[29] The Commission noted that

> Prior to about 1973, AEP simply rotated capacity additions among the operating companies. Because costs remained relatively stable, no one AEP company bore a disproportionate share of the burden of supplying the System's generation. Since that time, however, the "calculus of equitably distributing capacity additions has become more complex, due to the building of larger generating units, slower load growth and inflation." Because of these factors, "AEP has resorted to mechanisms such as unit power sales and joint ownership to accomplish a rotation and sharing of responsibilities."[30]

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28 *See* Opinion No. 311, 44 FERC ¶ 61,206 at 61,741 (1988).

29 *See id.* at 61,744.

30 *Id*. (footnotes omitted).

As AEP began planning extra-high voltage transmission[31] to allow for wider use of the centrally planned larger generating units, the Kentucky PSC, among others, raised cost causation concerns that local retail consumers were being improperly allocated costs for extra high voltage transmission to serve the needs of diverse electric customers.[32] The Transmission Agreement was the result.

Under the Transmission Agreement as initially proposed in 1984, costs for only EHV transmission would be shared among the AEP Retail Companies based on each retail company's actual investment in EHV lines compared to its system investment obligation.[33] As reflected in the Initial Decision, the proposed Transmission Agreement for EHV transmission contained a revised transmission cost obligation "computed by multiplying the total of all five operating companies'

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31 Extra-high voltage transmission included 345 kV, 500 kV, and 765 kV transmission ("EHV"). *American Elec. Power Serv. Corp.*, 37 FERC ¶ 63,032 at 3 (1986) ("Initial Decision").

32 Kentucky Public Service Commission Order, Case No. 8904 (providing history of the 765 kV Hanging Rock to Jefferson transmission line. In the late 1970's AEP planned a 765 kV transmission line originating in Ohio and terminating in Indiana but running 155 miles through Kentucky. Although Kentucky Power and AEP initially testified before the Kentucky PSC that 95% of the costs for the project's estimated $55 million price tag would be reimbursed by other AEP operating companies, by 1983 they asserted that the prior testimony was "erroneous" and that under AEP's cost allocation framework applicable at the time, 100% of the then $123 million in costs were to be allocated solely to Kentucky Power.) *Id*. at 2-3, available at https://psc.ky.gov/order_vault/Orders_1980-1988/Orders_1984/19008904_08031984.pdf (last accessed March 12, 2025).

33 Initial Decision, 37 FERC ¶ 63,032 at 3.

EHV investments at the end of the preceding year by the ratio of the particular company's maximum electric demand in the preceding year to the total of all the operating companies' maximum electric demands in that preceding year. This ratio is called MLR—for Member Load Ratio."[34] Payments would be made from or to transmission owning AEP Retail Companies based on the outcome of the MLR calculation.[35]

AEP submitted the Transmission Agreement for Commission approval.[36] Following protests from several parties, the Commission set the matter for hearing.[37] Among relevant changes ordered in the Initial Decision was that the sharing of costs would apply to all transmission down to 138 kV instead of just EHV facilities.[38] The Initial Decision made this determination on the basis that "the inclusion of 138 kV and above facilities would reduce the total payment to be made among the AEP operating companies, [and thus] AEP Service was obligated to prove that the

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34 *Id*.

35 This allocation method is referred to herein as the "MLR Method."

36 American Elec. Power Serv. Corp. Filing, Docket No. ER84-348-000 (filed on June 22, 1984). Certain parties argued that the Transmission Agreement was not subject to Commission jurisdiction, but the Commission rejected those arguments. Opinion No. 311, 44 FERC ¶ 61,206 at 61742.

37 *American Elec. Power Serv. Corp.*, 28 FERC ¶ 61,228 (1984), *order on clarification*, 32 FERC ¶ 61,110 (1985).

38 Initial Decision, 37 FERC ¶ 63,032 at 13.

exclusion of 138 kV and above facilities is just and reasonable."[39] The Commission upheld this determination, albeit on different grounds.[40] The Commission required the inclusion of 138 kV and above facilities on the basis that:

> It is likewise undisputed that all of these facilities are part of the integrated AEP transmission system that serves all of the native load customers of the AEP System. This Commission has a strong policy of requiring "rolled-in costing when any degree of integration of facilities has been shown."[fn] The conclusion is undisputed that the [high voltage] facilities serve a system transmission function.[41]

The Commission approved the MLR Method.[42] Under the MLR method, AEP would calculate each member's MLR based on the non-coincident peak demands of the AEP Operating Companies during the previous twelve months.[43] The highest peak demand of each AEP Operating Company would be summed, and each Member's MLR calculated as its peak demand in the previous twelve months divided by the sum of the (then) five Operating Companies' non-coincident peaks.[44]

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39 Order No. 311, 44 FERC ¶ 61,206 at 61747.

40 *Id*. at 61748 (finding that "the presiding judge has described the issue incorrectly. The question is whether the Transmission Agreement is just and reasonable as filed, and if such an agreement is not just and reasonable, whether the Transmission Agreement is just and reasonable if it is extended to include all facilities 138 kV and above.")

41 *Id*.

42 *Id*.

43 *Id*.

44 *Id*.

If an AEP Operating Company's transmission investment was deficit relative to its MLR share of the total system investment, then it would make monthly settlement payments distributed to the AEP Operating Companies with an investment surplus.[45]

2. AEP East Joins PJM

Effective October 1, 2004 the AEP Retail Companies placed their respective 22,300 miles of transmission facilities under the functional control of PJM.[46] The AEP Retail Companies placed under PJM functional control all transmission 69 kV and above meeting the PJM definition of Transmission Facilities, meaning the AEP transmission was integrated with the PJM transmission system.[47] Thereafter, in

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45 *Id*.

46 *See* Press Release, AEP's Eastern Grid Integrated Into PJM Interconnection RTO, Oct. 1, 2004, *available at* https://www.appalachianpower.com/company/news/view?releaseID=1674

47 The PJM Operating Agreement defines Transmission Facilities as: "'Transmission Facilities' shall mean facilities that: (i) are within the PJM Region; (ii) meet the definition of transmission facilities pursuant to FERC's Uniform System of Accounts or have been classified as transmission facilities in a ruling by FERC addressing such facilities; and (iii) have been demonstrated to the satisfaction of the Office of the Interconnection to be integrated with the PJM Region transmission system and integrated into the planning and operation of the PJM Region to serve all of the power and transmission customers within the PJM Region." https://agreements.pjm.com/oa/4539

2009, AEP created the AEP Transcos as additional members of PJM and though which AEP builds some Attachment M-3 projects.[48]

As a result of joining PJM, the transmission cost recovery for the AEP Retail Companies changed. The revenue requirement of all AEP East transmission under PJM operational control is submitted to PJM for collection through the PJM OATT. This includes 69 kV facilities, effectively lowering the voltage previously addressed by the Commission in Order No. 311. The AEP Retail Companies, as load-serving entities that take transmission service from PJM, pay the AEP zonal transmission rate. The charges allocated by PJM include both costs for regionally planned projects and those transmission projects self-planned by AEP as Supplemental Projects, or more recently under Attachment M-3 of the PJM OATT. PJM bills AEP for transmission service, including Network Integration Transmission Service ("NITS")[49] and other charges, used by the AEP Retail Companies, which AEP then allocates among customers in the AEP Zone. After unaffiliated customers in the AEP Zone are allocated certain costs, AEP Retail Companies allocate the remaining costs

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48 *See* American Elec. Power Serv. Corp. Filing, Docket No. ER10-355-000 (filed Dec. 1, 2009) (AEP's filing proposing formula rates for the PJM Transcos).

49 PJM bills on a 1 coincident peak ("1 CP") basis. PJM OATT, Section 34.1 (Monthly Demand Charge).

among themselves in a manner consistent with Appendix I of the AEP Transmission Agreement.[50]

The currently effective version of the AEP Transmission Agreement is reflected in a settlement agreement filed in 2010 in Docket No. ER09-1279-000.[51] PJM bills the AEP Zone on the 1 CP basis. Consistent with Appendix I of the AEP Transmission Agreement, AEP allocates the charge for NITS among the AEP Retail Companies on a 12 coincident peak ("12 CP") basis. Because the AEP zonal transmission rate includes the combined costs of the AEP Retail Companies' and Transcos' transmission investment, each of the AEP Retail Companies pay a share of all Supplemental and Attachment M-3 Projects located within the AEP Zone, which costs are currently allocated exclusively to the AEP seven-state zone consistent with Commission precedent.

B. History of Supplemental Projects and Attachment M-3

As noted above, prior to 2004, AEP centrally planned transmission to address AEP East transmission needs outside of any regional planning process. When AEP

50 American Electric Power Service Corporation, Settlement Filing, Docket No. ER09-1279-000 (Aug. 4, 2010). The AEP Transmission Agreement is not currently filed in eTariff. AEP filed a revised version of the Transmission Agreement in eTariff in 2022 in anticipation of AEP selling Kentucky Power and Kentucky Transco to another utility, but the filing was withdrawn after the Commission denied the application. Appalachian Power Company, Transmittal Letter, Docket No. ER22-1429-000 (Mar. 22, 2022).

51 *Id*.

joined PJM in 2004, PJM regionally planned most projects but had a category for Transmission Owner Initiated Projects.[52] In 2008, in an effort to decrease the latitude of individual transmission owner planning, PJM removed Transmission Owner Initiated Projects from its planning and added "Supplemental Projects."[53] A then existing PJM transmission owner, Baltimore Gas & Electric, supported the change because it "believe[d] that the elimination of the 'Transmission Owner Initiated' classification of projects will expand the category of projects that will be made subject to PJM Board approval, and that the introduction of the more limited category of 'Supplemental' projects that are affirmatively determined by PJM to fail to satisfy specified criteria identified . . . is also a significant improvement in the transparency and regional participation involved in PJM's transmission system planning processes under its Open Access Transmission Tariff."[54] A Supplemental Project is defined in PJM's Operating Agreement as

> a transmission expansion or enhancement that is not required for compliance with the following PJM criteria: system reliability, operational performance or economic criteria, pursuant to a determination by the Office of the Interconnection and is not a state public policy project pursuant to Operating Agreement, Schedule 6, section 1.5.9(a)(ii). Any system upgrades required to maintain the reliability of the system that are driven by a Supplemental

[52] *See generally* PJM's filing ins Docket No. OA08-32-000.

[53] *Id*.

[54] Baltimore Gas & Electric Company, Motion to Intervene and Statement in Support, filed Jan. 4, 2008 in Docket No. OA08-32-000, at 3.

> Project are considered part of that Supplemental Project and are the responsibility of the entity sponsoring that Supplemental Project.[55]

Baltimore Gas & Electric's expectation of limited local planning held true for a number of years as regional planning predominated and Supplemental Projects were a small percentage of transmission ratebase additions.[56]

In 2011 FERC sought to protect transmission rates by mandating competition for most regionally cost allocated projects.[57] While the results were lower rates for competed projects, the more significant result was an explosion of planning outside the regional process.[58] In PJM this meant an exponential increase in Supplemental Projects, which are cost allocated to a single zone regardless of beneficiaries,[59] planned in order for incumbent transmission to ensure that transmission additions in their service territories avoid the competition requirement.

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55 PJM Operating Agreement, Section 1 Definitions, available at https://agreements.pjm.com/oa/4539.

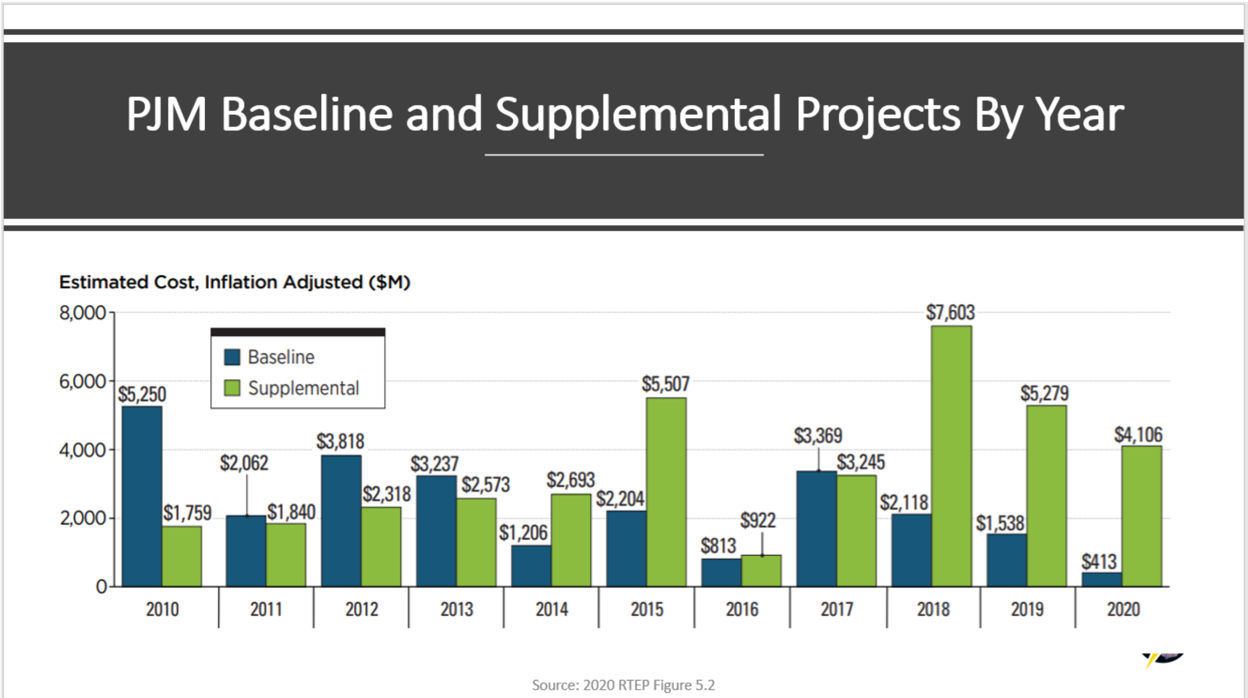
56 *See*, Figure 1, *infra*.

57 *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, Order No. 1000, 136 FERC ¶ 61,057 (2011), *order on reh'g*, Order No. 1000-A, 139 FERC ¶ 61,132, *order on reh'g*, Order No. 1000-B, 141 FERC ¶ 61,044 (2012).

58 *See*, https://rmi.org/increased-spending-on-transmission-in-pjm-is-it-the-right-type-of-line/.

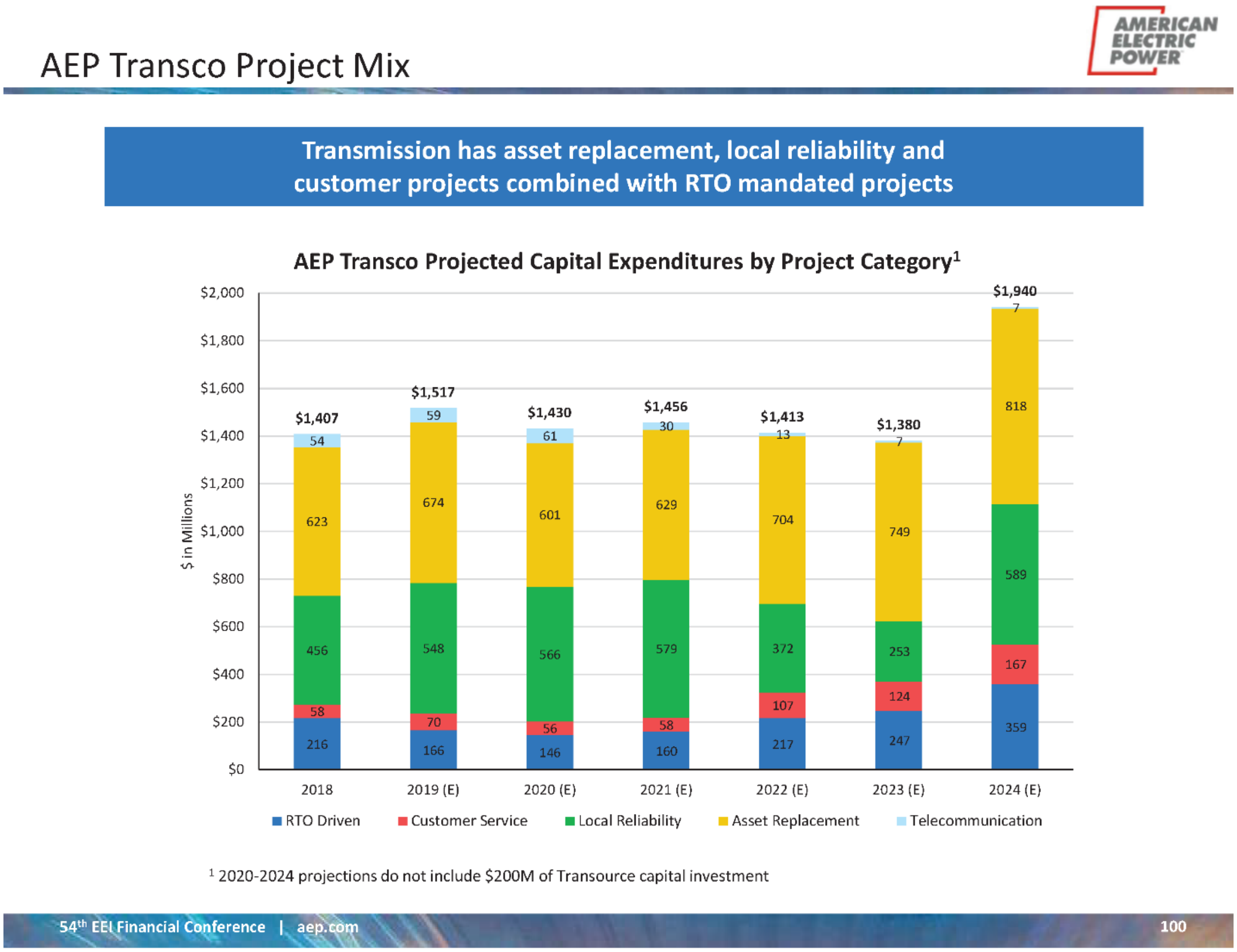
59 PJM Intra-PJM Tariffs, Schedule 12, OATT Schedule 12, 12.0.0, (14.0.0).

Figure 1:



AEP East was among the transmission owners increasing Supplemental Projects, a trend which has continued since 2020.

Figure 2:



On August 26, 2016, the Commission, pursuant to section 206 of the Federal Power Act, established a proceeding to determine whether the PJM transmission owners were complying with their Order No. 890[60] obligations related to openness, transparency, and information exchange with respect to planning Supplemental

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60 *Preventing Undue Discrimination and Preference in Transmission Service*, Order No. 890, 118 FERC ¶ 61,119 at P 3, *order on reh'g*, Order No. 890-A, 121 FERC ¶ 61,297 (2007), *order on reh'g*, Order No. 890-B, 123 FERC ¶ 61,299 (2008), *order on reh'g*, Order No. 890-C, 126 FERC ¶ 61,228 (2009).

Projects.[61] In their defense, the PJM transmission owners described Supplemental Projects as:

> projects that address reliability issues that do not rise to the level of a PJM Reliability Criteria violation, such as replacing equipment that has reached the end of its operational life, replacing failed equipment, transmission construction to address electrical topology and engineering issues within the PJM Transmission Owner's zone, maintain or improve service to its local load, add new retail distribution customers and enhance system resiliency or security.[62]

The outcome of that case was the Commission's adoption of Attachment M-3 of the PJM Tariff regarding the planning of Supplemental Projects.[63]

In 2019, in response to a PJM stakeholder effort to require regional planning of projects intended to address transmission reaching the end of operational life,[64] the PJM transmission owners introduced an expansion of Attachment M-3.[65] The expansion of Attachment M-3 added additional project categories beyond

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61 *Monongahela Power Co.*, 156 FERC ¶ 61,134 (2016) ("Show Cause Order").

62 Response To Show Cause, PJM Transmission Owners, filed October 25, 2016, in Docket No. EL16-71-000.

63 *Monongahela Power Co.*, 164 FERC ¶ 61,217 (2018).

64 *See, e.g.*, PJM Interconnection, L.L.C. Filing, filed July 20, 2020 in Docket No. ER20-2308-000.

65 PJM Interconnection, L.L.C. Filing, filed June 12, 2020 in Docket No. ER20-2046-000 (On behalf of certain transmission owners, PJM filed revisions to Attachment M-3 of the PJM OATT.)

Supplemental Projects, although all were intended to address local issues. The expanded Attachment M-3 specifically covered projects to address transmission facilities that have reached the end of their useful life.[66]

C. Examples Of AEP projects In Ohio, Indiana & Michigan For Which There Is No Identified Kentucky Need

Since 2019 AEP East has planned dozens of Attachment M-3 Projects within the PJM region at a cost of over $3.4 billion. Those projects are largely, if not exclusively, outside the state of Kentucky and, despite continued concerns raised by the Kentucky PSC,[67] continue to be allocated to Kentucky consumers as a result of the combined impact of the required single zone cost allocation for self-planned transmission, the CTOA zone size restrictions, and the existing Appendix I to the Transmission Agreement.

As reflected in the testimony of Rao Konidena, AEP East identified many of its projects as addressing purely "local" needs related to serving the retail load of individual retail service territories. As AEP readily acknowledges, much of its system is more than 60 years old, built before cost sharing among the AEP Retail Companies and before AEP moved toward EHV transmission to support its centralized generation planning when that was still occurring. For example, Mr.

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66 *PJM Interconnection, L.L.C.*, 172 FERC ¶ 61,136 at P 17 (2020).

67 *See supra* footnotes 14-15.

Konidena identified eight 138 kV projects in Indiana, some of which were conversions of original 69 kV facilities.[68] The $560 million in transmission ratebase additions had identified project needs for Customer Service or Equipment Condition/Performance Risk. There is no evidence from AEP's explanation of the project drivers that these projects arose as a result of serving Kentucky Power customers or that Kentucky Power customers in some way caused the need for the projects. Further, other than simply being part of the AEP corporate family, there is no evidence that Kentucky Power benefits from the projects in a manner commensurate with the more than $31 million allocated to Kentucky consumers from those projects.

The ninth Indiana project identified by Mr. Konidena is a 51-mile double circuit 345 kV project at a cost of over $200 million.[69] The Commission has found that double circuit 345 kV projects benefit the entirety of PJM such that 50 percent of the costs of regionally planned double circuit 345 kV projects are allocated across all of PJM.[70] While that finding would suggest that Kentucky Power, like all of PJM, may benefit from the Indiana double circuit 345 kV project, the finding instead highlights the problem with the current allocation system within the Transmission

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68 Konidena Testimony at 9.

69 *Id*.

70 *Old Dominion Elec. Coop. v. FERC*, 898 F.3d 1254, 1257 (D.C. Cir. 2018) *citing PJM Interconnection, LLC*, 142 FERC ¶ 61,214, PP 412–26 (2013).

Agreement in that only the AEP Zone is allocated costs from the identified EHV project despite the regional benefits. This is solely because the double circuit 345 kV project was self-planned by AEP. As the U.S. Court of Appeals for the District of Columbia Circuit has stated, the cost causation principle "focuses on project benefits, not on how particular planning criteria were developed."[71] Thus, allocating the costs of EHV transmission solely to the AEP Zone, and by extension Kentucky Power, when such facilities benefit PJM as a whole, likewise violates cost causation principles. Because the Transmission Agreement mandates that Kentucky Power pay for a portion of AEP self-planned facilities outside of Kentucky Power's service territory without determining the full scope of benefiting parties, the Transmission Agreement is unjust, unreasonable, unduly discriminatory or preferential. The status quo cost allocation, in discouraging regional planning in favor of self-planned projects, also degrades the overall advantage of RTO membership.

Mr. Konidena identifies several projects in Ohio and Michigan that suffer from the same problems as the Indiana projects.[72] Those projects are geographically remote from Kentucky and are likewise justified as necessary to serve local needs. Particularly projects that are 69 kV or 138 kV, and which are not in geographical proximity to Kentucky, have no demonstrated relationship to serving customers of

[71] *Old Dominion Elec. Coop. v FERC*, 898 F.3d 1254, 1262 (2018).

[72] Konidena Testimony at 12-20.

Kentucky Power. With the recent announcement of AEP selling a 19.9% stake in both the Ohio and Indiana & Michigan Transcos for $2.82B to a consortium consisting of private equity firm KKR and Canada's Public Sector Pension Investment Board, there is reason to believe that AEP investment in these regions will only continue to increase, further compounding the disparity for Kentucky consumers.[73] Another recent announcement that AEP secured a conditional commitment in the amount of $1.6B at a preferred interest rate from the U.S. Department of Energy's Loan Program Office to upgrade and/or replace transmission lines for reliability and to facilitate future economic growth in Indiana, Michigan, Ohio, Oklahoma, and West Virginia simply underscores where AEP plans to continue its investment in transmission, and it is not in Kentucky.[74]

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[73] Ethan Howland, *AEP to sell stake in transmission companies to KKR-PSP consortium for $2.8B*, UTILITY DIVE, Jan. 10, 2025, https://www.utilitydive.com/news/aep-transmission-kkr-psp-investments-ohio-michigan/737005/ (last accessed March 12, 2025); AEP, *Ohio and I&M Transcos Minority Interest Acquisition*, January 9, 2025, https://docs.aep.com/docs/investors/eventspresentationsandwebcasts/Transcos_Minority_Interest_Acquisition_Presentation.pdf (last accessed March 12, 2025).

[74] US DOE Program Supports Transmission Upgrades, available at https://www.aep.com/news/stories/view/9971/ (last accessed March 12, 2025).

D. Self-Planned Transmission Projects Outside Kentucky Power Are Not Needed For Kentucky Power To Serve Kentucky Retail Consumers

As noted above, until 1984 transmission built within a retail distribution company's footprint was allocated exclusively to that retail distribution service territory. The Kentucky PSC challenged that approach as AEP East planned EHV transmission in Kentucky Power's territory that was allocated exclusively to Kentucky Power while intended to benefit all AEP Retail Companies.[75] Indeed, the 765 kV project that led to the Kentucky PSC challenging AEP cost allocation originated in Ohio and terminated in Indiana but ran more than 150 miles though Kentucky and thus was to be 100 % cost allocated to Kentucky.[76] The Kentucky PSC objected to Kentucky consumers bearing the majority of costs for an EHV project geared to benefit electricity consumers in AEP East's other retail distribution service territories. The Kentucky PSC's objection led to the Transmission Agreement of 1984. After 40 years, the problem identified in the early 1980s has reversed itself.

While the EHV projects of the 1970s and 1980s identified a flaw in the cost allocation scheme for holistically planned transmission within the AEP footprint, four decades later the problem is not too narrow of a cost allocation regime for

75 *See*, *supra*, FN 32.

76 *Id*.

projects serving the entire footprint, but a regime that spreads what should be localized costs too broadly across AEP East's seven state footprint given the changes in AEP operations and its membership in PJM. In reviewing the 1984 Transmission Agreement which, as filed, addressed only transmission facilities of 345 kV and above, built to deliver centrally planned generation to load, the Commission required that the cost for all transmission 138 kV and above be shared.[77] At the time of that determination, while AEP East was a multi-state transmission system, it was one that was increasingly built around holistically planned generation facilities intended to serve those multi-state retail distribution service territories.[78] The Initial Decision on the 1984 Transmission Agreement found that "Cost equalization is appropriate for the AEP system because single system planning presupposes that **the members of the system will plan and build bulk power facilities to meet the demands of the system rather than the demands of the individual subsidiaries.**"[79] As the Initial Decision noted, the AEP Retail Companies then were "part of a single integrated electrical system which is operated as an integrated whole and centrally dispatched. Generation built by one company within its own territory may be used to supply electrical power consumed by customers of one or more of the other

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77 Opinion No. 311, 44 FERC ¶ 61,206 at 61747.

78 *Id*. at 61744, 61747-48.

79 Initial Decision, 37 FERC ¶ 63,032 at 4 [emphasis added].

companies."[80] The Commission used this holistic generation planning process as the basis for broad allocation of transmission costs for even lower voltage facilities based on Commission rolled-in rate treatment.[81]

That paradigm is no longer true given AEP East's participation in PJM and the lack of centralized generation planning. As noted above, in 2004 AEP East joined PJM, turning over operational control of all transmission to PJM. Now the AEP system that may have once been "operated as an integrated whole" is operated by PJM as an integrated whole with all other PJM controlled transmission to the benefit of all of PJM. Further, the AEP centralized generation paradigm also changed as FERC approved the "separation of Ohio Power's generation and power marketing businesses from its transmission and distribution businesses."[82] Kentucky Power's generation needs are primarily addressed by Kentucky Power's own generation entitlements.

Based on the significant changes in the AEP system in the last 40 years, it is no longer just and reasonable for the AEP Retail Companies to continue sharing the costs for all AEP self-planned transmission, transmission that is determined for AEP parent company purposes rather than the needs of individual retail utility footprints.

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80 *Id*. at 2.

81 Opinion No. 311, 44 FERC ¶ 61,206 at 61747-48.

82 *Ohio Power Co.*, 143 FERC ¶ 61,075 at P 1 (2013).

There is no evidence that the determinations made at AEP headquarters in Ohio as to what self-planned transmission AEP undertakes in the various AEP Retail Companies, or the AEP Transcos, other than Kentucky Power, have any relationship to serving the electricity customers of Kentucky Power. In the Initial Decision accepting, with revisions, the original Transmission Agreement, the Commission specifically rejected the argument that it should not adjudicate the fairness of allocation among AEP's Retail Companies because AEP is supposedly "neutral as among the various operating companies and has no financial interest in the movement of money from one subsidiary to another; it is merely a transfer from one corporate pocket to another."[83] In the section captioned "The Father-Knows-Best Argument," the Commission ALJ held that:

> This agency cannot abandon its duty to determine just and reasonable rates by assuming that the parent company is sufficiently disinterested so that its allocations between the operating utilities, and its determination of what is fair to each of them, may be relied upon. In fact, the parent company is not disinterested at all, as substantial differences in the total AEP system income may arise from the rate determinations made by state regulatory bodies as a result of whatever equalization payments are approved here. Even if the parent were completely disinterested, it is not charged by law with responsibility to determine the justness and reasonableness of the Agreement. This Commission is.[84]

83 Initial Decision, 37 FERC ¶ 63,032 at 5.

84 *Id*.

As discussed in the Testimony of Mr. Konidena, if there are NERC reliability concerns arising related to serving Kentucky Power load, PJM plans those projects at the regional level as Baseline transmission projects, with the costs allocated accordingly.[85] PJM planned projects are cost allocated based on the expected beneficiaries of the projects, with single circuit 345 kV and below allocated based on a dFax analysis, and projects that are double circuit 345 kV and above allocated 50% across PJM as a whole and 50% based on a dFax analysis.[86] Yet, if those exact same projects are self-planned by AEP, either in advance of NERC violations or whether needed at all, the costs are allocated exclusively to the seven-state AEP Zone, including Kentucky Power. As the Commission is aware, analysis of self-planned projects, including several AEP self-planned projects, found several examples of the misallocation of costs as a result of the required single zone allocation for self-planned transmission projects.[87]

To be clear, the Complainants are not challenging the Commission precedent that self-planned transmission projects that do not seek regional cost allocation must

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85 Konidena Testimony at 4.

86 PJM Schedule 12 b., available at https://agreements.pjm.com/oatt/4424.

87 LSP Transmission Holdings II, LLC and Central Transmission, LLC Comments in Support of Stakeholder Approved Section 205 Filing, Pterra, LLC ("Pterra Analysis of Supplemental Projects") Attachment, filed July 23, 2020 in Docket No. ER20-2308-000; *see also* Comments of LS Power Grid, LLC in Response to the Commission's Advanced Notice of Proposed Rulemaking, filed Oct. 12, 2021 in Docket No. RM21-17-000, at 56.

be allocated exclusively to the retail distribution service territory, if it has one, otherwise to the footprint of the party self-planning the transmission.[88] Rather, the Complaint challenges only the allocation of those 'local' project costs within and among the AEP Retail Companies and the justness, reasonableness, unduly discriminatory or preferential nature of the Transmission Agreement in the manner it allocates those costs. The testimony of Mr. Konidena makes clear that AEP itself has identified the issues causing the need for the projects with such justification based on customer needs within the individual AEP Retail Companies other than Kentucky Power.[89] It is unjust, unreasonable, unduly discriminatory or preferential to allocate the cost more broadly that the retail company directly causing the need for the self-planned project.

E. Appropriate Replacement Rate Under Section 206 Second Prong

Section 206 of the Federal Power Act requires that when the Commission finds an existing rate unjust and unreasonable *the Commission* must establish a replacement rate. Although Section 206 requires that a complainant propose an

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88 Order No. 1000-A at P 429. *See also*, Order No. 1000 at P 63, providing that "A local transmission facility is a transmission facility located solely within a public utility transmission provider's retail distribution service territory or footprint that is not selected in the regional transmission plan for purposes of cost allocation." *See also* Order No. 1000-A at P 430.

89 *KN Energy, Inc. v. FERC*, 968 F.2d 1295, 1300 (D.C. Cir. 1992)(cost causation requires that rates "reflect to some degree the costs actually caused by the customer who must pay them.")

appropriate replacement rate, the obligation to establish a replacement rate is exclusively the Commission's.[90] The Complainants propose that the appropriate replacement rate is for any AEP East self-planned transmission the cost allocation under the Transmission Agreement should be revised such that the cost for individual transmission projects remains exclusively with the retail distribution service territory where the project is located, and where the need arose, unless AEP makes a specific filing with the Commission to establish a factual basis for a different cost allocation for a specific project.

As noted in the preceding section, analyzing self-planned projects in a manner consistent with regionally planned projects would lead to project cost allocation that is significantly different than allocating costs solely to the retail distribution service territory of the AEP Retail Company in which the project is located. That approach however forces regional consumers to bear the same burden that the Complainants challenge—allocation of costs for a project that was developed for ratebase purposes of an AEP Retail Company or Transco rather than regional purposes. For this reason, the Complainants believe that the proper approach for a company that chooses to self-plan, or a parent company that dictates the self-planning among multiple retail

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90 *FirstEnergy Serv. Co. v. FERC*, 758 F.3d 346, 353 (D.C. Cir. 2014), *quoting Md. Pub. Serv. Comm'n v. FERC*, 632 F.3d 1283, 1285 n. 1 (D.C. Cir.2011) ("It is 'the Commission's job—not the petitioner's—to find a just and reasonable rate.'")

service companies or transcos, is to allocate the costs of such transmission solely to the retail distribution service territory where the project is located so that it can be appropriately analyzed by state regulators through transmission siting processes, if any.[91]

V. OTHER REQUIRED INFORMATION

A. Identification of the action or inaction (18 C.F.R. § 385.206(b)(1))

As noted herein, AEP has numerous AEP Retail Companies that are signatories to the Transmission Agreement. Although the Kentucky PSC, and, separately, the Kentucky Attorney General, have sought to engage AEP in a meaningful discussion of reforms to the allocation of transmission costs to more equitably allocate transmission costs for self-planned transmission, AEP has refused to address the excess allocation of costs to Kentucky Power.

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91 It should also be noted that a significant impediment to appropriate cost allocation in PJM is that the PJM transmission owners agreed among themselves to set the minimum size of the PJM transmission zones. Section 7.4 of the Consolidated Transmission Owners Agreement provides: "For purposes of developing rates for service under the PJM Tariff, transmission rate Zones smaller than those shown in Attachment J to the PJM Tariff, or subzones of those Zones, shall not be permitted within the current boundaries of the PJM Region; provided, however, that additional Zones may be established if the current boundaries of the PJM Region is expanded to accommodate new Parties to this Agreement."

B. Explanation of the Violation (18 C.F.R. § 385.206(b)(2))

The cost allocation among the Respondents reflected in the Transmission Agreement is unjust, unreasonable, unduly discriminatory or prejudicial to Kentucky electricity consumers and inconsistent with cost causation principles. Costs associated with transmission necessary to serve individual retail distribution service territories within a utility company with multiple retail distribution service territories across seven-states should be retained exclusively within the retail distribution service territory causing the need for the transmission facilities.

C. Business, Commercial, Economic, or Other Issues Presented (18 C.F.R. § 385.206(b)(3))

The economic impact of the unjust, unreasonable, unduly discriminatory or preferential rates is significant. Kentucky Power's service territory in Kentucky is an area of the state that is among the most economically disadvantaged in the nation and the most distressed in Kentucky with a median income 27% below the state at large.[92] As discussed in D, the misallocation addressed in the Complaint means $15 million per year in excess rates to Kentucky Power customers. That burden makes it even more difficult for an area already burden economically to compete for new industry and jobs.

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92 https://www.arc.gov/wp-content/uploads/2022/02/Kentucky-ARC-4-YR-Plan-FY-2022.pdf (last accessed March 12, 2025) at 8.

D. Financial Impact (18 C.F.R. § 385.206(b)(4))

Though testimony in Kentucky Power related proceedings before the Kentucky PSC, the expert consultant for the Kentucky Attorney General, Office of Rate Intervention determined that the annual cost of excess transmission rates is approximately $15 million per year.[93]

E. Practical Impact (18 C.F.R. § 385.206(b)(5))

N/A

F. Other Pending Proceedings (18 C.F.R. § 385.206(b)(6))

While there are no proceedings with the Commission addressing the specific issue raised in the Complaint, the relief requested in the Complaint filed December 19, 2024 by certain customer focused entities, EL 25-44-000, could address some of the issues raised by the Complainants. To the Complainant's understanding, the relief sought in that complaint would prohibit the type of self-planned projects at issue here, if those projects are 100 kV or more, permitting only regional planning of such facilities and appropriate cost allocation based on that regional planning.

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[93] Kentucky Public Service Commission, ERRATA version of the February 21, 2022 Joint Direct Testimony and Exhibits of Stephen J. Baron filed on behalf of the Attorney General and KIUC, Case No. 2021-00481, pages 12–27 (March 29, 2022), available at Microsoft Word - Baron Testimony 2-21-22 - (ERRATA) (last accessed March 12, 2025).

G. Relief Requested (18 C.F.R. § 385.206(b)(7))

The Kentucky Public Service Commission and the Kentucky Attorney General request that the Commission determine that the cost allocation among Respondents as reflected in the Transmission Agreement is unjust, unreasonable, unduly discriminatory or preferential, and that the Commission require amendment of the Transmission Agreement to ensure that costs for self-planned transmission projects are allocated exclusively to the AEP Retail Company distribution service territory for which the project is need. Complainants request that the Commission establish a refund effective date as of the date of the Complaint.

H. Attachments (18 C.F.R. § 385.206(b)(8))

Attachment 1, Form of Notice;

Exhibit A, Testimony of Rao Konidena.

I. Other Processes to Resolve Complaint (18 C.F.R. § 385.206(b)(9) & (10))

For years through its retail regulatory proceedings the Kentucky Public Service Commission has engaged with AEP regarding the excess transmission costs allocated to Kentucky consumers, but AEP has not voluntarily agreed to reform its practices or cost allocation methodology. Likewise, the Attorney General has submitted testimony addressing the excess costs incurred by AEP self-planned transmission additions in states other than Kentucky. The Complainants believe that further efforts to resolve the issue would not be fruitful.

J. Notice of Complaint (18 C.F.R. § 385.206(b)(10))

A form of notice of the filing of this Complaint, suitable for publication in the Federal Register, is provided as Attachment 1.

Respectfully submitted

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Counsel to Kentucky Public Service Commission

CERTIFICATE OF SERVICE

I hereby certify that I have caused a copy of the foregoing Complaint and attachments to be served electronically on the Respondents, to the individuals listed on the Commission's Corporate Officials List and interested persons, in accordance with 18 C.F.R. § 385.206(c).

Michael R. Engleman
Michael R. Engleman

Dated: March 12, 2025

Attachment 1

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Kentucky Public Service Commission, Attorney General of the Commonwealth of Kentucky	)	
Complainants	)	
v.	)	Docket No. EL25-___-000
American Electric Power Service Corporation, Appalachian Power Company, Columbus Southern Power Company, Indiana Michigan Power Company, Kentucky Power Company, Kingsport Power Company, Ohio Power Company, and Wheeling Power Company	)	
Respondents		

NOTICE OF COMPLAINT
March 12, 2025

Take notice that on March 12, the Kentucky Public Service Commission and the Attorney General of the Commonwealth of Kentucky (collectively, "Complainants") filed a formal complaint against American Electric Power Service Corporation, Appalachian Power Company, Columbus Southern Power Company, Indiana Michigan Power Company, Kentucky Power Company, Kingsport Power Company, Ohio Power Company, and Wheeling Power Company (collectively "Respondents") pursuant to Sections 206, 306 and 309 of the Federal Power Act, 16 U.S.C. §§ 824e, 825c, and 825h and 18 C.F.R. § 385.206, requesting that the Commission find that the Transmission Agreement among Respondents is unjust, unreasonable, unduly discriminatory, or preferential in the manner it allocates costs to Kentucky Power, thus harming Kentucky consumers. The Complainant's each have a statutory obligation to ensure that Kentucky electricity consumers are protected from excessive electricity rates. The Complaint requests a refund effective date on the date the Complaint is filed.

Complainants certify that copies of the Complaint were served on contacts for the Respondents as listed on the Federal Energy Regulatory Commission's ("Commission") list of Corporate Officials.

Any person desiring to intervene or to protest this filing must file in accordance with Rules 211 and 214 of the Commission's Rules of Practice and Procedure (18 C.F.R. §§ 385.211 and 385.214). Protests will be considered by the Commission in determining the appropriate action to be taken, but will not serve to make protestants parties to the proceeding.

Any person wishing to become a party must file a notice of intervention or motion to intervene, as appropriate. The Respondent's answer and all interventions, or protests must be filed on or before the comment date. The Respondent's answer, motions to intervene, and protests must be served on Complainants.

The Commission encourages electronic submissions of protests and interventions in lieu of paper using the "eFiling link at http://www.ferc.gov. Persons unable to file electronically should submit an original and 14 copies of the protest or intervention to the Federal Energy Regulatory Commission, 888 First Street, N.E., Washington, DC 20426.

This filing is accessible on-line at http://www.ferc.gov, using the "eLibrary" link and is available for review in the Commission's Public Reference Room in Washington, D.C. There is an "eSubscription" link on the web site that enables subscribers to receive email notification when a document is added to a subscribed docket(s). For assistance with any FERC Online service, please email FERCOnlineSupport@ferc.gov, or call (866) 208-3676 (toll free). For TTY, call (202) 502-8659.

Comment Date: 5:00 p.m. Eastern Daylight Time on (insert date).

Debbie-Anne A. Reese
Acting Secretary

Exhibit A

I. INTRODUCTION AND WITNESS IDENTIFICATION

Q: Please state your name, employer, title, and business address.

A: My name is Rao Konidena. I am the President of Rakon Energy LLC. Rakon Energy is owned and operated by me. My business address is Rakon Energy LLC, Roseville, MN 55113.

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

A: I am testifying on behalf of the Kentucky Public Service Commission ("KY PSC").

II. SUMMARY OF TESTIMONY

Q: Please summarize your testimony.

A: With multiple examples of Attachment M-3 projects in the American Electric Power (AEP) East zone in PJM Interconnection, my testimony illustrates that Kentucky should not be at the receiving end of cost allocation for projects that benefit retail consumers in other AEP states such as Ohio, Indiana and Michigan. Specifically, my testimony focuses on Attachment M-3 projects such as transmission line rebuilds, new 345/138 kV stations, and new 138 kV stations that address local needs for project drivers, such as customer need, equipment material condition and risk, operational flexibility and efficiency and infrastructure resiliency.

Kentucky consumers should not be singled out for cost allocation simply because they are part of the AEP family of retail companies spread across seven states in PJM. Because the drivers of Supplemental and M-3 projects are claimed to be local, the costs should remain with the individual retail distribution company driving the transmission need.

Q: Are you sponsoring any exhibits with your testimony?

A: Yes. My resume and a list of local projects in Ohio, Indiana and Michigan.

III. QUALIFICATIONS

Q: Please describe your current position and provide your educational and professional experience related to this testimony.

A: I have been an independent energy consultant for over six years, primarily focusing on Regional Transmission Organization practices and policy. From September 2003 to May 2018, I worked in Transmission Asset Management at Midcontinent Independent System Operator ("MISO"). I started as an Applications Engineer for Planning, where I ran Loss of Load Expectation ("LOLE") studies, Capacity Benefit Margin ("CBM") calculations, and Load Deliverability analysis for the MISO Transmission Expansion Plan ("MTEP").

I was later promoted to Lead of Resource Forecasting in 2006, responsible for a team of engineers running capacity forecasting. That forecasting work is incorporated in the MTEP non-transmission alternatives section. After a promotion to Manager of Resource Forecasting in 2009, I led Demand Response and Energy Efficiency forecasting for MTEP.

I worked in compliance, process, and project management for the Transmission Asset Management ("TAM") division as Senior Manager of TAM Operations from 2013 to 2015. In this role, my team and I were responsible for division-wide financial and strategic planning, supporting corporate planning and compliance efforts. I came back to the Policy Studies department in the Principal Policy Advisor role for MISO in 2015, leading the long-term load forecasting project with Purdue University's State Utility Forecasting Group and Applied Energy Group demand response ("DR"), energy efficiency ("EE") and distributed generation ("DG") potential study at MISO.

Before leaving MISO in 2018, I led policy efforts on energy storage and distributed energy resources within economic transmission planning. I presented to MISO state commissions, including the Iowa Utilities Board, the South Dakota Public Utilities Commission, and the Organization of MISO States.

I received a Bachelor of Engineering in Electrical and Electronics Engineering from Bangalore University, a Master of Science in Electrical Engineering from the University of Texas at Arlington, and a Master of Business Administration from the University of Minnesota. My qualifications and experience are further detailed in my resume provided as Exhibit 1.

Q: How does that experience and education relate to your testimony in this matter?

A: The fifteen years of transmission planning experience that I gained at MISO by working on multiple iterations of MTEP directly relates to my testimony here because PJM is within FERC jurisdiction like MISO. Early in my career at MISO, I had put together reliability need based transmission project justifications for inclusion in the MTEP like PJM's RTEP. My undergraduate and graduate education in electrical engineering is also directly related to my testimony due to the technical nature of AEP's projects, specifically related to voltage class, the project drivers, the state those projects are based in, the type of equipment (e.g., capacitor bank, transformer, fault interrupting device) and differentiating between rebuilding versus replacing a transmission line.

Q: Have you previously testified before the Federal Energy Regulatory Commission (FERC) ("Commission") or State Commissions?

A: On January 3, 2025, I submitted an Affidavit before the Commission on behalf of Voltus, Inc regarding Southwest Power Pool's Second Compliance Filing in FERC Order 2222. Docket No. ER22-1697. I have previously submitted an Affidavit before the Commission on behalf of the PJM Industrial Load Coalition regarding PJM Interconnection's (PJM) Reserves Pricing Proposal. Docket No. ER19-1486-000 and Docket No. EL19-58-000. I have also submitted an Affidavit before the Commission on behalf of Missouri Joint Municipal Electric Utilities Commission, Missouri River Energy Services, and WPPI Energy regarding the Midcontinent Independent System Operator's (MISO) External Resource Zone proposal. Docket No. ER18-1173-001.

I have previously testified before four state commissions (Illinois, Maryland, Pennsylvania and Wisconsin) in transmission line certificate dockets. I have submitted direct testimonies on behalf of my clients at the following state commissions:

1. California Public Utilities Commission (Diablo Canyon Power Plant extension docket and Application of Pacific Gas and Electric Company to Recover in Customer Rates the Costs to Support Extended Operation of Diablo Canyon Power Plant docket)
2. Illinois Commerce Commission (Certificates of Public Convenience and Necessity)
3. Kansas Corporation Commission (Demand Response Aggregator docket)
4. Maryland Public Service Commission (Transmission Line Certification of Public Convenience And Necessity docket)
5. Massachusetts Department of Public Utilities (Eversource, National Grid and Unitil Energy Storage Tariffs)
6. Minnesota Public Utilities Commission (Aggregator of Retail Customer docket)
7. Public Utilities Commission of Nevada (Integrated Resource Planning docket)
8. North Carolina Utilities Commission (Duke Energy Carolinas General Rate Case and Duke Energy Carolinas Carbon Plan Integrated Resource Plan)
9. Pennsylvania Public Utilities Commission (Transmission Line rebuild Letter Of Notification docket and First Energy Pennsylvania Base Rate Case) and
10. Public Service Commission of Wisconsin (Transmission Line Certificate of Public Convenience & Need docket).

IV. PJM'S M-3 PROCESS

Q: Please describe PJM's Regional Transmission Expansion Plan (RTEP) process and how Individual Transmission Owner Planning fits into that process.

A: PJM's RTEP process has three main transmission project categories – 1) Baseline, 2) Network, and 3) Attachment M-3.[1] As a Regional Transmission Organization (RTO), PJM is responsible for assessing transmission needs in the next five years and over a 15-year

[1] https://agreements.pjm.com/oatt/31552 "Each Transmission Owner shall be responsible for planning and constructing in accordance with Schedule 6 of the Operating Agreement as provided in this Attachment M-3, to the extent applicable, (i) Asset Management Projects, as defined herein, (ii) Supplemental Projects, as defined in section 1.42A.02 of the Operating Agreement, and (iii) any other transmission expansion or enhancement of Transmission Facilities that is not planned by PJM . . .".

horizon. Transmission projects identified in this needs assessment are called Baseline projects.

Regional RTEP and Subregional RTEP projects fall under this Baseline Upgrades category at PJM.[2] Baseline projects are primarily reliability-based (e.g., NERC Transmission Planning standards) transmission projects. PJM studies these projects as part of the 24-month reliability planning cycle, which includes identifying short-term and long-term reliability upgrades.

PJM combines quite a few drivers in this baseline project identification, including NERC Regional Entity (e.g., ReliablityFirst) criteria, PJM Operations, PJM Load Serving Entity Capacity plans, Generator and Transmission Interconnection Requests, Transmission Owner and other stakeholder transmission development plans, Long-Term Transmission Service Requests, and several economic and operational risk drivers.

These Baseline projects fall under PJM Manual M-14B and are approved by the PJM Board of Managers.

Customer-funded upgrades, local upgrades, or merchant network upgrades paid by an Interconnection Customer are Network projects. New Service Customers, customers seeking new transmission service or generator interconnection drive Network projects at PJM.[3]

Q: Please describe PJM's Attachment M-3 process.

A: This Attachment M-3 is an attachment to the PJM's Open Access Transmission Tariff governing transmission owner initiated transmission projects.

Attachment M-3, including Supplemental projects at 230 kV and above are presented at the Transmission Expansion Advisory Committee (TEAC), and below 230 kV are presented at the Subregional TEAC.

There are four stages to this M-3 process.[4]

The first stage starts with an Assumptions meeting. PJM Transmission Owner ("TO") assumptions are posted 20 days before the Assumptions meeting, and stakeholder comments are due ten days after the Assumptions meeting.

The next stage is the Needs meeting. TOs send the project needs to PJM, and PJM posts the slides on its TEAC meeting website ten days before the meeting. Once again,

[2] Id.
[3] Id.
[4] PJM Transmission Owners Attachment M-3 Process Guidelines, https://www.pjm.com/-/media/planning/rtep-dev/pjm-to-attachment-m3-process-guidelines.ashx.

stakeholders have ten days to comment after the Needs meeting. The Project Driver and the Problem Statement are presented at the Needs meeting.

After the Needs stage, there is a Solutions meeting. Like the Needs meeting, the slides are posted ten days before the Solutions meeting, and stakeholder comments are due ten days after the Solutions meeting.

Finally, each Transmission Owner will finalize for submittal to PJM the Attachment M-3 Projects for inclusion into the Local Plan in accordance with section 1.3 of Schedule 6 of the Operating Agreement. Before the Local Plan is integrated into PJM's Regional Transmission Expansion Plan ("RTEP"), stakeholders have at least 10 days to comment.[5]

Q: What is the definition of an "Attachment M-3 Project"?

A: PJM's OATT defines an "Attachment M-3 Project" as follows:[6]

"*"Attachment M-3 Project" means (i) an Asset Management Project that affects the connectivity of Transmission Facilities that are included in the Transmission System, affects Transmission Facility ratings or significantly changes the impedance of Transmission Facilities; (ii) a Supplemental Project; or (iii) any other expansion or enhancement of Transmission Facilities that is not excluded from this Attachment M-3 under any of clauses (1) through (5) of section (a). "Attachment M-3 Project" does not include a project to address Form No. 715 EOL Planning Criteria.*"

According to this definition, an Attachment M-3 Project is an Asset Management Project that increases the ratings or changes the impedance of Transmission Facilities. It is also a Supplemental Project. Finally, any other expansion or enhancement of Transmission Facilities planned by a Transmission Owner falling under the following five criteria are deemed exceptions to Attachment M-3 Projects:[7]

1. NERC Reliability Standards or the applicable Regional Entity Standards.
2. Individual Transmission Owner planning criteria filed under FERC Form. 715.
3. Criteria to address economic constraints.
4. State Agreement Approach expansions or enhancements.
5. An expansion or an enhancement addressed by the RTEP Planning Process.

Q. What is an "Asset Management Project"?

A. It is a name created by PJM transmission owners to describe building new transmission infrastructure to replace transmission facilities that have reached the end of operational life.

Q: Please provide a list of the main project drivers of Attachment M-3 Projects.

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[5] https://agreements.pjm.com/oatt/31552
[6] PJM OATT Attachment M-3, https://agreements.pjm.com/oatt/31552.
[7] *Id.*

A: According to PJM Transmission Owners Attachment M-3 Process Guidelines document, there are five project drivers:[8]

1. Customer Service
2. Equipment Material Condition, Performance and Risk
3. Operational Flexibility and Efficiency
4. Infrastructure Resilience
5. Other.

Some Attachment M-3 Projects may have multiple drivers, a combination of one or more project drivers such as Customer Service and Operational Flexibility and Efficiency.

Q: Please describe the Customer Service project driver.

A: Attachment M-3 Project with a Customer Service driver is for the purpose of providing "[s]ervice to new and existing customers. Interconnect new customer load. Address distribution load growth, customer outage exposure, equipment loading".[9]

For example, American Electric Power (AEP) has a Customer Service driver project in Columbus, OH, in the AEP 2024 Local Plan. AEP states, "Four customers have requested distribution service at a site South of AEP's existing Trabue station in Columbus, OH. The customers have indicated a total peak demand of 33.5 MVA of new capacity and 5.5 MVA of alternate capacity at the site. The customer has a requested an in service date of 2/29/2024."[10]

Q: Please describe the Equipment Material Condition, Performance and Risk project driver.

A: Attachment M-3 Project with an Equipment Material Condition, Performance and Risk driver is for the purpose of taking care of "Degraded equipment performance, material condition, obsolescence, including at the end of the useful life of equipment or a facility, equipment failure, employee and public safety and environmental impact".[11] This category is referred to by transmission owners as Asset Management.

An example of an AEP project with an Equipment Material Condition, Performance and Risk driver in the AEP 2024 Local Plan is work done at the Barranshe Station and Coleman – Spring 69 kV line in Pike County, KY. AEP states that the 15 relays at the Barranshe

[8] Page 8, PJM Transmission Owners Attachment M-3 Process Guidelines, https://www.pjm.com/-/media/planning/rtep-dev/pjm-to-attachment-m3-process-guidelines.ashx.
[9] *Id.*
[10] Slide 72, AEP Local Plan - 2024 https://www.pjm.com/-/media/committees-groups/committees/srrtep-w/postings/2024/aep-local-plan-submission-of-the-supplemental-projects-for-2024-rtep.ashx.
[11] Page 8, PJM Transmission Owners Attachment M-3 Process Guidelines.

Station need replacement, and ten permanent outages have caused 2.6M minutes of interruption for the distribution customers.[12]

Q: Please describe the Operational Flexibility and Efficiency project driver.

A: Attachment M-3 Project with an Operational Flexibility and Efficiency driver is for the purpose of "Optimizing system configuration, equipment duty cycles and restoration capability, minimize outages".[13]

The East Liverpool Station Upgrade project in East Liverpool, Ohio, is an example of an AEP project with an operational flexibility and efficiency driver in the AEP 2024 Local Plan. One aspect of the project consists of replacing the existing 138 kV MOAB/ground switch at the 138 – 69 kV transformer. It lacks a fault interrupting device on the high side, requiring remote-end fault clearing from FirstEnergy substations.[14]

Q: Please describe the Infrastructure Resilience project driver.

A: Attachment M-3 Project with an Infrastructure Resilience driver is for the purpose of "improv[ing] system ability to anticipate, absorb, adapt to, and/or rapidly recover from a potentially disruptive event, including severe weather, geo-magnetic disturbances".[15]

An example of an Infrastructure Resilience driver project combined with a Customer Service driver is installing a hard tap on the North Findlay–Ebersol circuit near the customer's station in Findlay, Ohio. The customer has requested transmission service for a temporary load of 30 MVA at a site east of AEP's North Findlay site. Installing in-line dead ends to support sectionalizing the tap improves the system's ability to serve the temporary customer.[16]

Q: Please describe the Other project driver.

A: Attachment M-3 Project with an Other driver is for the purpose of "Meet[ing] objectives not included in other definitions such as, but not limited to, technological pilots, industry recommendations, environmental and safety impacts, etc.".[17]

An example of an Other project is AEP's Robison Park – Argenta/Weeds Lake 345 kV circuit into Northern Indiana Public Service Company NIPSCO's Hiple Station.

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[12] Slides 9-10, AEP Local Plan - 2024.
[13] Page 8, PJM Transmission Owners Attachment M-3 Process Guidelines.
[14] Slides 5-6, AEP Local Plan – 2024.
[15] Page 8, PJM Transmission Owners Attachment M-3 Process Guidelines.
[16] Slides 93-94, AEP Local Plan – 2023, https://www.pjm.com/-/media/committees-groups/committees/srrtep-w/postings/2023/aep-local-plan-submission-of-the-supplemental-projects-for-2023-rtep.ashx.
[17] Page 8, PJM Transmission Owners Attachment M-3 Process Guidelines.

V. PJM'S TRANSMISSION ZONES

Q: Please briefly describe the purpose of PJM's Transmission Zones.

A: PJM Transmission Zones are defined in Attachment J of OATT.[18] PJM has 21 Transmission Zones.[19] The purpose of these Transmission Zones is to allocate costs for transmission projects based on their project category. As mentioned earlier, PJM has three main project categories: Baseline, Network and Supplemental. PJM's Schedule 12 describes the cost allocation of Baseline Transmission Reliability Upgrades.[20]

Cost allocation for required Network Upgrades is primarily assigned to the Project Developer and Eligible Customers.[21] The cost allocation for Supplemental Projects is covered below.

Q: Please describe briefly how costs for Supplemental or M-3 transmission projects are allocated in PJM's Transmission Zones.

A: For Supplemental Projects or M-3 transmission projects, 100% of the costs are assigned to the PJM Transmission Owner Zone.[22]

VI. AEP'S PROJECTS, IN GENERAL

Q: Please describe your methodology in selecting AEP's M-3 transmission projects.

A: I selected 26 AEP M-3 transmission projects for the purposes of this testimony are directly from AEP's PJM TEAC presentations in the past five years (2019-2023). Not all M-3 projects are shown here for the sake of brevity. Only projects above $21 Million are shown for illustrative purposes. But the points I make regarding the illustrative projects would be applicable to any AEP M-3 projects.

Q: Please describe the timeframe for selecting AEP's M-3 projects.

A: AEP's M-3 projects were selected from the past five years: 2019-2023.

Q: Please describe the main solution categories of AEP's M-3 projects.

A: The selected 26 AEP M-3 projects fit into the following main solution categories:

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[18] PJM Open Access Transmission Tariff, Attachment J https://agreements.pjm.com/oatt/4443
[19] Map of PJM's Transmission Zones, https://www.pjm.com/library/~/media/about-pjm/pjm-zones.ashx.
[20] Page 63, PJM Manual 14B: PJM Region Transmission Planning Process, Revision: 56, Effective Date: June 27, 2024, https://www.pjm.com/-/media/documents/manuals/m14b.ashx.
[21] Page 45, PJM Manual 14H: New Service Requests Cycle Process, Revision: 00, Effective Date: July 26, 2023, https://www.pjm.com/-/media/documents/manuals/m14h.ashx.
[22] Slide 8, Cost Allocation Today and Possible Alternatives: Review of Options Discussed to Date, Ken Seiler, Vice President – Planning, Interconnection Policy Workshop: Session 3 July 22, 2021, https://www.pjm.com/-/media/committees-groups/committees/pc/2021/20210722-workshop-3/20210722-item-03-interconnection-policy-reforms-overview-presentation.ashx.

1. Rebuild and replace: Rebuilding and replacing an existing transmission line or infrastructure. Eighty-five percent (22 total) of the projects fell in this category.
2. New Station: Building a new 345/138 kV station, for example. Only four projects fell into this category.

Q: Please provide a table containing the solution categories of AEP's M-3 projects in Indiana.

A: AEP's M-3 projects in Indiana are shown below:

Table 1: AEP's M-3 Projects in Indiana

AEP Description of Tx project	AEP Claimed Project Driver	Cost ($Million)
1. Southern Muncie – Rebuild an existing line, build a new 138 kV transmission line, and retire a tap line.	Customer Service	$68.70
2. Jay-Allen – Rebuild a 138 kV line, rebuild a 69 kV station, and retire a tap line.	Customer Service	$71.00
3. Allen -Robison Park – Rebuild 12 miles of a 138 kV double circuit line.	Equipment Condition/Performance/Risk	$34.90
4. Hillcrest-Adams – Selected solution combines several projects, including rebuilding/replacing 69 kV transmission lines with 138 kV transmission lines.	Equipment Condition/Performance/Risk	$116.20
5. Sorenson-Desoto – Rebuild an approximately 51.1-mile transmission line using double circuit 345 kV and other work.	Equipment Condition/Performance/Risk	$202.40
6. Albion Area – Conducted in two phases, AEP planned to rebuild an existing approximately 8.7-mile line using double circuit 138 kV, rebuild approximately 8.5 miles of an existing 138 kV transmission line, rebuild a 69 kV transmission line as double circuit 138 kV (but will energize as 69 kV), and build a new approximately 11.7 mile double circuit 138/69 kV transmission line, and other work.	Equipment Condition/Performance/Risk	$124.80
7. Robison Park-Sowers – Rebuild 13.6 of existing transmission line with double circuit 138 kV capable transmission line and other work.	Equipment Condition/Performance/Risk	$43.30
8. Pendleton-Makahoy – Rebuild approximately 15 miles of 138 kV transmission line and replace a 138/34.5 kV transformer.	Equipment Material Condition, Performance and Risk	$38.50
9. Hartford Area – Rebuild approximately 14.7 miles of existing 138 kV transmission line, rebuild approximately 18.7 miles of 69 kV transmission, and other work.	Equipment Condition/Performance/Risk	$65.40

Q: Please provide a table containing the solution categories of AEP's M-3 projects in Ohio.

A: AEP's M-3 projects in Ohio are shown below:

Table 2: AEP's M-3 Projects in Ohio

AEP Description of Tx project	AEP Claimed Project Driver	Cost ($Million)	New Station
1. Wapakoneta – Build a new 345/138 kV station, a new 138 kV station, two new 138 kV transmission lines, and remove an existing 138 kV transmission line.	Customer Service	$66.20	Y
2. Anguin Station – Selected solution combines several projects, including expanding an existing station by constructing a new 345 kV/138 kV station yard.	Customer Service	$91.30	Y
3. Athens Area – Selected solution combines several projects, including replacing and installing 138 kV transmission infrastructure.	Equipment Material/Condition/Performance/Risk	$55.50	
4. Crooksville-Philo – Rebuild 12 miles of existing 138 kV transmission line and other work.	Equipment Material/Condition/Performance/Risk	$30.90	
5. Cameron– Selected solution combines several projects, including constructing a new 500-138 kV station and various 138 kV transmission facilities.	Customer Service	$68.70	Y
6. Millbrook Park-South Point – Rebuild 35 miles of a double circuit 138 kV line and other work.	Equipment/Material/Performance/Risk	$148.70	
7. Shannon Station – Rebuild approximately 9 miles of 138 kV transmission lines, construct approximately 4.6 miles of greenfield 138 kV transmission line, and other work.	Equipment Material/Condition/Performance/Risk, Operational Flexibility and Efficiency	$60.80	
8. South Coshocton-Wooster – Rebuild 37.7-mile 138 kV transmission line and other work.	Equipment Condition/Performance/Risk	$97.54	
9. Haviland-VanWert – Rebuild 69 kV transmission line using 138 kV double circuit design and other work.	Customer Service	$32.57	

10. Fostoria-East Lima – Rebuild 41.3-miles of existing transmission line with double circuit 138 kV line.	Equipment Material/Condition/Performance/Risk	$95.98	
11. Dover to South Canton – Rebuild two 138 kV transmission lines.	Equipment Material Condition, Performance and Risk; Operational Flexibility & Efficiency	$89.58	
12. Conesville-Bixby – Rebuild approximately 46.1 miles of 345 kV transmission line.	Equipment Material/Condition/Performance/Risk	$154.53	
13. Central Ohio – Rebuild approximately 19 miles of double circuit 345 kV.	Equipment Material/Condition/Performance/Risk	$116.70	
14. Seneca County, Ohio – Rebuild approximately 33 miles of 138 kV transmission lines.	Operational Flexibility, and Customer Service	$82.12	
15. New Albany, Ohio – Among other work, build a new substation.	Customer Service	$21.08	Y
16. Philo-Newcomerstown – Selected solution combines various work, including rebuilding 138 kV transmission lines and new 138 kV transmission lines.	Equipment Material Condition, Performance and Risk; Operational Flexibility & Efficiency	$117.50	
17. Philo-Howard – Rebuild an existing line as 138 kV double circuit for approximately 64 miles, rebuild another segment as 138 kV single circuit for approximately 19 miles, and perform other work.	Equipment Material/Condition/Performance/Risk	$187.84	

Q: Have you found similar projects in Ohio, Indiana and Michigan listed on AEP's website?

A: Yes. I have attached them as Exhibit 2 with their identified project need. I have highlighted multiple projects with "to improve electric reliability for customers" in Ohio, Indiana and Michigan to illustrate one example of projects clearly providing localized electric reliability for retail customers within retail distribution service territories. Other project needs are "to strengthen", "to upgrade" and "replace" or "rebuild". This Exhibit shows there are multiple projects in Ohio, Indiana and Michigan that clearly illustrate how the retail customers in those states benefit from projects in their specific retail distribution service territories.

Q: Why does your testimony focus on AEP's M-3 transmission projects in Ohio, Indiana and Michigan?

A: As I explain below, even though Kentucky does not benefit from Attachment M-3 projects in Ohio, Indiana and Michigan, AEP's transmission projects in Ohio, Indiana and Michigan are selected to illustrate that due to the cost allocation method at PJM, Kentucky bears these project costs.

VII. AEP'S PROJECTS IN OHIO

Q: Please provide examples of M-3 projects in Ohio that AEP refers to as a "rebuild."

A: An example of a rebuild solution M-3 project in Ohio is the Philo – Howard 138 kV Line Rebuild project in AEP Local Plan – 2021.[23] The main project driver is Equipment Material/Condition/Performance/Risk. The total estimated cost of the project is $187.84M.[24] The projected In-Service Date is 6/1/2028.[25]

There are five parts to the Philo – Howard 138 kV Rebuild project in Ohio:[26]

1. Rebuild from Howard to Ohio Central as 138kV double circuit (64 miles), using 795 ACSR conductor. Estimated Cost: $142.26 Million (s2524.1)
2. Rebuild from Ohio Central to Philo as 138kV single circuit (19 miles), using 795 ACSR conductor. The existing Ohio Central Philo #2 138kV circuit will be retired. Update both terminal stations to account for the retired circuit. Estimated Cost: $43.45 Million (s2524.2)
3. At Millwood station, retire the 138kV flip flop switching scheme, including the 2 138kV switches. Install 2 new 138kV switches and replace the 138kV through path risers & bus. Reconfigure the 138kV T line entrances. Estimated Cost: $1.32 Million (s2524.3)
4. At West Trinway station, replace 138kV through path risers & bus. Estimated Cost: $0.12 Million (s2524.4)
5. Modify 138kV protective relay settings at Philo, Culbertson, Ohio Central, Academia, North Bellville, North Lexington, and Howard stations. Estimated Cost: $0.69 Million (s2524.5)

[23] Slide 135, AEP Local Plan – 2021.
[24] Slide 136, Id.
[25] Id.
[26] Slide 136, AEP Local Plan – 2021.

Q: What is your concern with rebuilding solution M-3 projects in Ohio?

A: Assuming that the facilities remain necessary, my concern with the above example of rebuilding solution M-3 projects in Ohio is some portion of the nearly $200 million in project costs are assigned to Kentucky Power customers without any showing that those customers benefit. Most of the M-3 projects are rebuilding 50-60 year old transmission lines, which were originally built to serve retail consumers in Ohio. Over time, the transmission line costs started getting shared across all AEP operating companies in the East through the Transmission Agreement, and then the AEP East zone in PJM upon AEP joining PJM. Even though these rebuild projects benefit the retail consumers in Ohio, due to PJM's cost allocation methodology for Attachment M-3 projects, AEP is assigning these costs to Kentucky. Retail consumers in Kentucky are paying in addition to retail consumers in Ohio.

Q: Please provide examples of a new 345/138 kV station solution M-3 project in Ohio.

A: An example of a new 345/138 kV station solution M-3 project in Ohio is the Wapakoneta project in AEP Local Plan 2019.[27] The total expected customer load is 127 MW. The main project driver is Customer Service. The total estimated cost of the project is $66.2M.[28] The project is In-Service as of 12/05/2022.

There are five components to the Wapakoneta project:

1. Build a new 345/138 kV Gristmill Station cutting into the Southwest Lima – Shelby 345 kV line. Estimated Cost: $25.8M (S1856.1)
2. Build a new 138 kV Gemini Station southeast of the City of Wapakoneta to serve the load request. Estimated Cost: $8.9M (S1856.2)
3. Build a new 138 kV line connecting Gristmill to Gemini Stations. Estimated Cost: $9.8M (S1856.3)
4. Build a new 138 kV line from the new 138 kV Gemini Station to existing West Moulton 138 kV Station. Rebuild the West Moulton 138 kV Station as a 4 breaker ring bus. Estimated Cost: $14.7M (S1856.4)
5. Remove the existing City of St Marys hard tap off the Southwest Lima –West Moulton 138 kV line and bring it into West Moulton 138 kV station (~0.2 mi away). Estimated Cost: $7.0M (S1856.5)

Q: What is your concern with the new 345/138 kV station solution M-3 projects in Ohio?

A: Similar to my concern with the rebuild solutions, my concern with the above example of new 345/138 kV station M-3 projects in Ohio is that they do not benefit the retail consumers in Kentucky. The new 345/138 kV station solution is built to serve new retail consumers in

[27] Slide 22, AEP Local Plan – 2019.
[28] Slide 23, Id.

the City of Wapakoneta, Ohio. Even though these new station projects benefit the retail consumers in Ohio, due to PJM's cost allocation methodology for Attachment M-3 projects, AEP is assigning these costs to Kentucky. Retail consumers in Kentucky are paying in addition to retail consumers in Ohio.

Q: Please provide examples of a new 138 kV station solution M-3 project in Ohio.

A: An example of a new 138 kV station solution is the Anguin Station project in AEP Local Plan – 2020.[29] The main project driver is Customer Service. The customer's initial load was 150 MW, with the ultimate load reaching 720 MW around Q4 2026.[30] The project is In-Service as of 7/27/2021, and the estimated cost was $91.3M.[31]

There are seven components to the Anguin Station project:[32]

1. Construct 2-138 kV circuits (~1.5 miles) from Babbitt Station to a new Anguin Station using 2 bundled 1033 ACSS conductor per circuit. (S2139.1) Estimated Cost: $15.2M
2. Construct 2-138 kV circuits (~.4 miles) from Anguin Station to a new customer station using 795 ACSS conductor. (S2139.2) Estimated Cost: $2.5M
3. At the existing 138 kV Babbitt Station, install 4-138 kV 4,000A 63kA breakers to accommodate the new 138 kV double circuit to Anguin Station, 2-138kV 4,000A 63kA bus tie breakers, a 57.6MVAr capacitor bank with protection, and a 138kV 4,000A 63kA CB to serve AEP-Ohio's requested delivery point. (S2139.3) Estimated Cost: $6.6M
4. Construct Anguin Station in a breaker and a half arrangement utilizing 8-138 kV 4,000A 63kA breakers and 2-57.6MVAr capacitor banks with protection. (S2139.4) Estimated Cost: $24.0M
5. Cut into existing Jug Street-Kirk 345kV circuit into a new 345 kV yard at Babbitt Station. Relocate Babbitt-Kirk 138kV circuit exit at Babbitt Station. (S2139.5) Estimated Cost: $3.3M
6. At Babbitt Station, install 3-3,000A, 63kA CB's in ring bus configuration at the 345 kV yard, a new 345/138kV 675 MVA transformer, and a new control house. Install 1-138 kV capacitor bank (54.7 Mvar) with high side protection. Install 9-138 kV, 4,000A 63kA CB's including a new 138kV yard and two short lines to connect both yards. Cost includes purchase of land for the required expansion. (S2139.6) Estimated Cost: $39.4M
7. Kirk 138kV –Update line relaying. (S2139.7) Estimated Cost: $0.3M

[29] Slide 2, AEP Local Plan – 2020.
[30] Id.
[31] Slide 3, Id.
[32] Id.

Q: What is your concern with the new 138 kV station solution M-3 projects in Ohio?

A: Similar to my concerns with the new 345/138 kV station and 500/138kV station, I am concerned that Kentucky is paying for new 138 kV station solution M-3 projects in Ohio without any benefit to Kentucky's retail consumers.

Q: Please describe your reasoning on why AEP's proposed transmission projects in Ohio are not needed for AEP to serve Kentucky retail customers.

A: As illustrated by the examples provided, these M-3 projects are unnecessary for meeting Kentucky's transmission needs. They appear to be caused by localized issues due to aging equipment and new customer demand (e.g., Wapakoneta project) in Ohio and not caused by Kentucky's consumers. This suggests that the costs and impacts should be addressed within Ohio's jurisdiction rather than being unfairly attributed to Kentucky's consumers. Attachment M-3 cost allocation methodology at PJM allows AEP to assign the costs of rebuilds and new station projects to Kentucky customers, even when these projects are designed solely to address local reliability or load growth needs for Ohio's retail consumers.

Q: Please summarize your reasons on why AEP's proposed transmission projects in Ohio with different project drivers do not benefit Kentucky.

A: Projects in Ohio with equipment material condition as a driver do not benefit Kentucky because those projects were originally built to serve retail customers in Ohio. Any rebuild at those locations continues to benefit retail customers in Ohio not Kentucky. Similarly projects in Ohio with customer service as a driver do not benefit Kentucky because they benefit new customers or existing customers in Ohio. Building a new 138 kV line cutting into existing 138 kV lines that exist to serve retail customers at that location continues to provide customer service benefit for retail customers in Ohio not Kentucky. Projects in Ohio with operational flexibility and efficiency as a driver involve replacing components at existing stations whose primary purpose is to serve local retail customers in Ohio not Kentucky. Finally, projects in Ohio with infrastructure resilience as a driver provide resilience for local retail customers in Ohio not Kentucky. Hence, AEP's proposed transmission projects in Ohio irrespective of the project driver do not benefit Kentucky.

VIII. AEP'S PROJECTS IN INDIANA

Q: Please provide examples of rebuild solution M-3 projects in Indiana.

A: An example of a rebuild solution M-3 project in Indiana is the Southern Muncie in AEP Local Plan – 2019.[33] The main project drivers are Equipment Condition / Performance / Risk, Operational Flexibility and Efficiency and Customer Service.

[33] Slide 14, AEP Local Plan – 2019.

The Customer Service project driver is due to AEP Distribution requesting a new delivery point at Arnold Hogan station and the old Delco site to accommodate the Delco Battery Site. Additionally, AEP Distribution has received multiple customer requests at the industrial park near the Delco Battery Site.

The Operational Flexibility and Efficiency project driver is due to the need to retire the Elmridge tap line.

The Equipment Condition, Performance and Risk project driver are due to the condition of multiple substations, as shown below:[34]

Table 3 - Equipment Condition, Performance and Risk driver details for Southern Muncie

Substation	Condition
Medford	Transformer 1 – 1959 vintage. Extremely high values of combustible gases. Breakers A, B, C – 1943-53 vintage FK oil breakers without containment.
23rd Street	Breakers B, C, D, E, J, K – 1971 vintage FK oil breakers without containment.
Arnold Hogan	Distribution Transformer 2 – 1970 vintage. Experienced a failure in 1999.
Blaine Street	Breaker E – 1971 vintage FK oil breakers without containment.
Arnold Hogan – 23rd Street	1963 wood crossarm construction, subject to 20 open A conditions and 26 open B conditions, and in the past 10 years 47 structures had active maintenance performed.

The total estimated cost of the project was $68.7M.[35] The project is In-Service as of 5/4/2023.[36]

There are a total of nine components to the Southern Muncie rebuild project.

Q: What is your concern with rebuilding solution M-3 projects in Indiana?

A: My concern with the above example of rebuilding solution M-3 projects in Indiana is that they do not benefit the retail consumers in Kentucky. Most of the M-3 projects are rebuilding 50-60 year old transformers, breakers and transmission lines, which were originally built to serve retail consumers in Indiana. Over time, when AEP brought all operating companies under one single corporate umbrella, the transmission line costs started getting shared across the entire AEP East zone in PJM. Even though these rebuild projects benefit the retail consumers in Indiana, due to PJM's cost allocation methodology for Attachment M-3 projects, AEP is assigning these costs to Kentucky. Retail consumers in Kentucky are paying instead of retail consumers in Indiana.

[34] Slides 14-17, AEP Local Plan -2019.
[35] Slide 19, Id.
[36] Id.

Q: Please provide examples of a new 138/69 kV transformer solution M-3 project in the Indiana/Michigan border.

A: An example of a new 138/69 kV transformer solution M-3 project in the Indiana/Michigan border is one component of the Niles Area Improvements in AEP Local Plan – 2020.[37] At Kenzie Creek station in Indiana, AEP is installing a 138/69kV XFR, 3 138kV breakers, 5 69kV breakers and a 14.4Mvar cap bank to allow for the retirement of Pokagon's 69 kV transmission yard. (S2167.1) The estimated cost is $12M.[38]

Additionally, AEP is building the new 138/69/34kV Boundary station to serve the new 34.5kV distribution load and to separate the Swanson and University Park load from the network. (S2167.6) The estimated cost is $13.6M.[39]

The project driver for both projects is the Equipment Material, Condition, Performance and Risk. The projected In-Service Date is 5/2/2025.[40]

Q: What is your concern with the new 138/69 kV transformer solution M-3 projects in the Indiana/Michigan border?

A: AEP has several improvements planned for the Niles Area, which is near the Indiana/Michigan border.[41] The examples provided above are just 1-2 examples of new 138/69 kV transformer and new 138/69/34.5 kV station projects. These projects primarily benefit portions of Michigan and Indiana by enhancing their local grid infrastructure, not Kentucky's. Hence, Kentucky should not have to pay for these Attachment M-3 projects.

Q: Please provide examples of a new 138 kV station solution M-3 project in Indiana.

A: An example of a new 138 kV station M-3 project in Indiana is building a new 138 kV station (Fogwell) in the clear near the existing GM Fort Wayne station. This project was part of the Sub Regional RTEP Committee PJM West in 2017.[42] The main project driver is Customer Service. Due to General Motors increasing production facilities at their Fort Wayne Trucking Plant, AEP must add a new 138 kV yard Fogwell station. The customer's initial load was 28 MVA, with the peak load reaching 45 MVA.[43] The project is In-Service as of 12/2/2018, and the estimated cost was $8.4M.[44]

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[37] Slides 45-51, AEP Local Plan – 2020.
[38] Slide 50, Id.
[39] Id.
[40] Slide 51, Id.
[41] https://aeptransmission.com/michigan/NilesArea/
[42] Slides 35-36 https://www.pjm.com//-/media/committees-groups/committees/srrtep-w/20180108/20180108-reliability-analysis-update.ashx.
[43] Id.
[44] Slide 36, Id.

Q: What is your concern with the new 138 kV station solution M-3 projects in Indiana?

A: AEP adding a new 138 kV yard at General Motor's Fort Wayne station in Indiana due to GM increasing its production facility is a clear example of Kentucky not benefiting from but paying for an M-3 project.

Q: Please provide examples of a new 345 kV breaker solution M-3 project in Indiana.

A: An example of a new 345 kV breaker solution in Indiana is the Delaware – Desoto Line in AEP presented at the TEAC meeting in 2018.[45] The project drivers are Equipment Material, Condition, Performance and Risk and Operational Flexibility and Efficiency. Equipment Material and Condition is the driver because the College Corner -Delaware 138 kV circuit is a 1941 vintage and the Delaware – Deer Creek is a 1927 vintage.

The Operational Flexibility and Efficiency is the driver because any time the 48-mile Tanner Creek 345 kV line needs maintenance, AEP must take a critical EHV bus outage because the line is hard-tapped onto the Desoto 345 kV bus 1.[46]

The project is In-Service as of 12/28/2020, and the estimated cost was $21.1M.[47]

Q: What is your concern with the new 345 kV breaker solution M-3 project in Indiana?

A: My concern with the new 345 kV breaker solution at the Delaware – Desoto Line in Indiana is Kentucky is paying for this project even though Kentucky does not benefit.

Q: Please describe your reasoning on why AEP's proposed transmission projects in Indiana are not needed for AEP to serve Kentucky retail customers.

A: As illustrated by the examples above, Kentucky is bearing costs for projects that provide no direct benefit to its customers. The proposed transmission projects appear to be caused by localized issues due to aging equipment and new customer demand in Indiana (e.g., General Motor's upgrade) and not caused by Kentucky's consumers. This suggests that the costs and impacts should be addressed within Indiana's jurisdiction rather than being unfairly attributed to Kentucky's consumers. Attachment M-3 cost allocation methodology at PJM enables AEP to assign the costs of rebuilds and new station projects to Kentucky customers, even when these projects are designed solely to serve the needs of Indiana's retail consumers.

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[45] Slides 13-14, https://www.pjm.com//-/media/committees-groups/committees/teac/20180503/20180503-teac-reliability-analysis-update.ashx.
[46] Slide 13, Id.
[47] Slide 14, Id.

Q: **Please summarize your reasons on why AEP's proposed transmission projects in Indiana with different project drivers do not benefit Kentucky.**

A: Projects in Indiana with equipment material condition as a driver do not benefit Kentucky because those projects were originally built to serve retail customers in Indiana. Rebuilding 50-60 year old transformers, breakers and transmission lines continues to benefit retail customers in Indiana not Kentucky. Similarly projects in Indiana with customer service as a driver do not benefit Kentucky because they benefit new customers or existing customers in Indiana. Building a new 138 yard at GM's production facility in Indiana provides customer service benefit for retail customers in Indiana not Kentucky. Projects in Indiana with operational flexibility and efficiency as a driver involve replacing components at existing stations with 1920's/1940's vintage whose primary purpose is to serve local retail customers in Indiana not Kentucky. Finally, projects on the Indiana/Michigan border are too far away to benefit retail customers in Kentucky. Hence, AEP's proposed transmission projects in Indiana irrespective of the project driver do not benefit Kentucky.

IX. AEP'S PROJECTS IN MICHIGAN

Q: **Please provide examples of rebuild solution M-3 projects in Michigan.**

A: An example of a rebuild solution M-3 project in Michigan is the Main Street-Riverside 34.5 kV Line Rebuild project in AEP Local Plan – 2020.[48] The project driver is the Equipment Condition, Performance and Risk.

The Main St.-Riverside 34.5kV line will be rebuilt on the center line approximately 4.1 miles of Main St-Riverside 34.5kV line with DOVE 556.5 ACSR 26/7. (S2345.1) The estimated cost is $13.3M. At Riverside Station, AEP will replace (2) 138kV breakers and (2) 34.5kV breakers at Riverside. While at the station and taking advantage of the outage AEP will install a new 34.5kV breaker to bring Whirlpool customer, whose delivery point is currently one tower outside of the station, into Riverside station. AEP will install high side circuit switcher to 138/69-34.5kV transformer. (S2345.2) The estimated cost is $3.3M. Hence, the total cost is $16.6M for this project. And the projected In-Service Date is 2/14/2024.[49]

Q: **What is your concern with the rebuild solution M-3 project in Michigan?**

A: Similar to my concerns above, I am concerned that the rebuild solution in Michigan does not benefit Kentucky retail consumers .

Q: **Please describe your reasoning on why AEP's proposed transmission projects in Michigan are not needed for AEP to serve Kentucky retail customers.**

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[48] Slides 236-238, AEP Local Plan 2020.
[49] Slide 238, Id.

A: As illustrated by the example above, AEP's proposed transmission projects unfairly shift costs to Kentucky for projects that provide no direct benefit to its residents. The proposed projects appear to be caused by localized issues due to aging equipment and new customer demand in Michigan (e.g., Whirlpool) and not caused by Kentucky's consumers. This suggests that the costs and impacts should be addressed within Michigan's jurisdiction rather than being unfairly attributed to Kentucky's consumers. Attachment M-3 cost allocation methodology at PJM allows AEP to assign the costs of rebuilds and new station projects to Kentucky customers, even when these projects exclusively benefit Michigan's retail consumers, such as the Whirlpool customer. .

X. COST ALLOCATION

Q: Based on your above analysis, do you have a recommendation for the Commission on the appropriate cost allocation for AEP's M-3 projects in Kentucky?

A: As my testimony makes clear, the allocation of Supplemental or Attachment M-3 projects to Kentucky consumers does not follow the claimed drivers for those projects. If it is appropriate to allocate costs to Kentucky consumers distant from such projects, then the transmission benefits to all integrated regional consumers that benefit should likewise be analyzed, but Commission regulations do not permit regional allocation of individual transmission owner planned transmission additions. Kentucky consumers should not be singled out for cost allocation simply because the Kentucky consumers are part of the AEP family of retail companies spread across seven states in PJM. Because the drivers of Supplemental and M-3 projects are claimed to be local, the costs should remain with the individual retail distribution company driving the transmission need.

Q: Is the Kentucky Public Service Commission aware of this cost allocation disparity?

A: Yes, as mentioned in a recent Order in Case No:2020-00174, the Kentucky Public Service Commission (PSC) has put Kentucky Power Company (KPCo), AEP's operating company in Kentucky, on notice stating that KPCo's "transmission planning and investment activities are not sustainable and must be substantively addressed in the near future".[50]

XI. CONCLUSION

Q: Please provide a summary of your conclusions.

A: The examples of Attachment M-3 projects in the AEP states of Ohio, Indiana and Michigan confirm that Attachment M-3 projects address retail distribution service territory needs and thereby benefit the local retail consumers in those distribution service territories not Kentucky consumers. Hence, there is ample justification for Attachment M-3 costs to

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[50] KY PSC Order in Case No:2020-00174 at 60, available at https://psc.ky.gov/pscscf/2020%20Cases/2020-00174/20210113_PSC_ORDER.pdf.

remain with the retail distribution company and not be shared across AEP operating companies.

Q: Does this complete your testimony?

A: Yes, it does.

UNITED STATES OF AMERICA

BEFORE THE

FEDERAL ENERGY REGULATORY COMMISSION

Kentucky Public Service Commission, Attorney General of the Commonwealth of Kentucky	)	
Complainants	)	
	)	Docket No. EL25-___-000
v.	)	
American Electric Power Company Service Company, Appalachian Power Company, Columbus Southern Power Company, Indiana Michigan Power Company, Kentucky Power Company, Kingsport Power Company, Ohio Power Company, and Wheeling Power Company	)	
Respondents	)	

AFFIDAVIT

Pursuant to 28 U.S.C. § 1746, I state under penalty of perjury that the foregoing is true and correct to the best of my information and belief.

Executed this 8th day of March 2025.

Rao Konidena

Exhibit 1

APPENDIX A – RAO KONIDENA RESUME

RAO KONIDENA

ENERGY MARKET EXPERTISE IN DISTRIBUTED ENERGY RESOURCES

Roseville, MN 55113 Cell: 612-594-9257 · rkonidena76@gmail.com

Rao Konidena is an independent energy consultant. He worked at the Midcontinent Independent System Operator (MISO) for 15 years. Before he left MISO, he was the Principal Advisor for Policy Studies, working on energy storage and distributed energy resources. At MISO, Rao worked in management and non-management roles around resource adequacy, economic planning, business management, and policy functions.

Rao is the President of the Finnish American Chamber of Commerce – Minnesota (FACC-MN) and sits on the Board of Ever Green Energy and Minnesota Solar Energy Industries Association (MnSEIA).

EXPERIENCE

RAKON ENERGY LLC, Roseville, MN
President & Chief Executive Officer (CEO) May 2018 – Present

Providing consulting services related to Federal and state energy policies focusing on energy storage and distributed energy resources

- Consumer advocates and non-profit organizations have engaged the expertise of Rakon Energy to provide an opinion on whether Non-Transmission Alternatives were sufficiently modeled in transmission line Certificate of Need proceedings.
- A renewable energy developer engaged Rakon Energy to provide MISO expertise for their renewable energy project portfolio in various stages and study cycles of the Generator Interconnection Queue and the capacity credit impact from MISO's seasonal capacity construct.
- An Independent Power Producer engaged Rakon's services to understand MISO's seasonal resource adequacy construct and its impact on Power Purchase Agreement negotiations with a MISO utility.
- An aggregator engaged Rakon Energy as part of the team to represent their interests at RTO stakeholder committees on FERC Order 2222.

- Rakon Energy was part of the team engaged by a technology company to represent their interests at the PJM RTO. Another similar company hired Rao to navigate MISO's market rules for data center interconnection.
- Advanced Energy Economy and the Natural Resources Defense Council's Sustainable FERC Project engaged Rakon to monitor MISO's FERC Order 2222 implementation process.
- The Commonwealth of Pennsylvania's Office of Consumer Advocate engaged Rakon Energy LLC to support OCA's response to the questions posed by the Pennsylvania Public Utility Commission's Secretary in the policy proceeding - Utilization of Storage Resources as Electric Distribution Assets.
- A prominent solar advocacy group currently engaged Rao for expert testimony work in Nevada and Minnesota IOUs IRP filing.
- He submitted comments to Minnesota and Colorado Public Utilities Commission on Integrated Distribution Planning dockets.
- He has provided expert testimony support for Environmental Law and Policy Center (ELPC) at the Public Service Commission of Wisconsin (PSCW) on the MISO Multi-Value Project (MVP) line in Wisconsin.
- He provided affidavit support for the Office of the People's Counsel of the District of Columbia (OPC-DC) at the Federal Energy Regulatory Commission (FERC) on PJM's Reserves Pricing Proposal and municipal utilities in Wisconsin and Missouri at FERC on MISO's Resource Adequacy construct.
- He provided advocacy support for Energy Storage Association (ESA) at MISO on FERC Order 841 Compliance.
- He provided training as part of the Tuatara team on DERs to Colombia's grid operator XM and the ESTA International team on energy storage benefits to Mexican regulator CRE.

Advisor, Volunteer, Pro-Bono assignments

- Rao presented on Distributed Energy Resources (DER) and peer-reviewed Demand Side Management and DER plans for Central American regulators, as part of NARUC International Peer Review.
- Rao presented and shared best practices around the impact of provisioning ancillary services. At an Eastern Africa regional workshop organized by the United States Energy Agency (USEA), the United States Agency for International Development (USAID) and the Power Africa initiative.

MIDCONTINENT INDEPENDENT SYSTEM OPERATOR (MISO), Eagan, MN
Principal Advisor, Policy Studies Aug 2015 – May 2018

- Recognized as an expert on all thing's energy storage and distributed energy resources from an economic transmission planning perspective
- Project manager for long term independent load forecast and demand response/energy efficiency/distributed generation potential study.
- MISO representative on Department of Energy (DOE) US DRIVE Grid Interaction Technical Team

Senior Manager, Transmission Asset Management Operations Feb 2013 – July 2015

- He engaged the division lead in the development of strategic initiatives and operating plans.
- Rao chaired the Economic Modeling Framework Working Group of international Grid operators GO-15.

Manager, Resource Forecasting (started at Engineer II) Sep 2003 – Jan 2013

- ***Main Accomplishments***
  - In this role, I directed the Demand Response & Energy Efficiency potential study for MISO, with the support of Global Energy Partners consultants.
  - Directed the MISO Energy Storage Study identifying the economic potential for grid-scale energy storage in MISO footprint, providing strategic consulting services to investor-owned utilities, public power utilities, asset owners, and investors.
- ***Regulatory Experience***
  - Responsible for analytical assessments that meet MISO's Federal Energy regulatory compliance obligations as well as our Transmission Owners (e.g., FERC Market-based rates).
  - Responsible for supporting state regulators and MISO Board of Directors with technical analysis related to policy drivers.

PWRSOLUTIONS, Inc., Dallas, TX (Consulting) May 2001 – August 2003
Student Intern and Electrical Engineer

- Rao executed generator interconnection studies for Independent Power Producers (IPPs) clients.
- Analyzed future generator and transmission needs in the Eastern Interconnection.

EDUCATION

THE UNIVERSITY OF MINNESOTA, Minneapolis, Minnesota
Carlson School of Management
Master of Business Administration, Global Executive Program May 2011
Emphases: Strategic Management, International Business

- Responsible for all financial aspects of marketing mobile charging services for Electric vehicles in the Singapore market.

UNIVERSITY OF TEXAS AT ARLINGTON, Arlington, Texas
Energy Systems Research Center (ESRC)
Master of Science in **Electrical Engineering** May 2002

- Master's Thesis in Economic Analysis of Distributed Generation (Photovoltaics (P.V.) and Fuel Cells)

BLOG POSTING, PUBLICATIONS & PRESENTATIONS

1. Co-Author for a graduate level textbook titled "Modern Electricity Systems: Engineering, Operations, and Policy to address Human and Environmental Needs". Release date - August 2022 with Wiley.
2. **He has authored multiple publications in Electricity Journal, Renewable Energy World (blog), and other peer-reviewed industry journals.**

BOARD & VOLUNTEER ACTIVITIES

- Board of Directors, Ever Green Energy. Sep 2019 – present
- Board of Directors, Minnesota Solar Energy Industries Association. Sep 2020 – Sep 2023.
- President, Finnish American Chamber of Commerce – Minnesota (FACC-MN). Jan 2016 - present

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Letter of Notification of PPL Electric Utilities Corporation, Filed Pursuant To 52 Pa. Code Chapter 57 Subchapter G, For Approval To Rebuild The Existing Double-Circuit Stanton-Summit #3 And #4 230 kV Transmission Lines Connecting the Stanton 230 kV Substation And A Two-Pole Turn Structure that are Respectively Located in Luzerne and Lackawanna Counties, Pennsylvania	:	Docket No. A-2022-3037374

VERIFICATION

I, Rao Konidena, hereby state that the facts set forth in my Direct Testimony, OCA Statement 1, are true and correct (or are true and correct to the best of my knowledge, information, and belief) and that I expect to be able to prove the same at a hearing held in this matter. I understand that the statements herein are made subject to the penalties of 18 Pa.C.S. § 4904 (relating to unsworn falsification to authorities).

DATED: July 7, 2023
*348275

Signature: Rao Konidena
Rao Konidena

Consultant Address: Rakon Energy, LLC
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Roseville, MN 55113