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March 4, 2022

Via eTariff

The Honorable Kimberly D. Bose, Secretary Federal Energy Regulatory Commission 888 First Street, NE Washington, DC 20426

Re: American Electric Power Service Corporation
Docket No. ER22-1195-000
Proposed Revisions to Attachments H-14 and H-20 of PJM Tariff

AEP-Liberty Utilities Transaction-Related Filing

Dear Secretary Bose:

Pursuant to Section 205 of the Federal Power Act ("FPA"), 16 U.S.C. § 824d (2006), and Part 35 of the Federal Energy Regulatory Commission's ("Commission") regulations, 18 C.F.R. Part 35, American Electric Power Service Corporation ("AEPSC"), on behalf of Appalachian Power Company, Indiana Michigan Power Company, Kentucky Power Company ("KPCo"), Ohio Power Company, and Wheeling Power Company (collectively referred to as the "AEP East Companies") and AEP Appalachian Transmission Company, Inc., AEP Indiana Michigan Transmission Company, Inc., and AEP Kentucky Transmission Company, Inc., ("AEP Kentucky Transco"), AEP Ohio Transmission Company, Inc., and AEP West Virginia Transmission Company, Inc. (collectively referred to as the "AEP East Transcos") hereby submit proposed revisions to Attachment H-14 and Attachment H-20 of the PJM Open Access Transmission Tariff ("Tariff").

This filing is related to a proposed transaction under which ownership of KPCo and AEP Kentucky Transmission Company, Inc., will be transferred to Liberty Utilities Co. ("Liberty") (the "Transaction"). Following the completion of the Transaction, KPCo will no longer be

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¹ Pursuant to Order No. 714, this filing is submitted by PJM on behalf of the AEP East Operating Companies and the AEP East Transcos as part of an XML filing package that conforms with the Commission's regulations. PJM has agreed to make all filings on behalf of the PJM Transmission Owners in order to retain administrative control over the PJM Tariff. Thus, AEPSC has requested PJM submit the proposed revisions in the eTariff system as part of PJM's electronic Intra PJM Tariff.

affiliated with the AEP East Companies, and AEP Kentucky Transco will no longer be affiliated with the AEP East Transcos.

In this filing, AEPSC submits proposed changes to Attachment H-14 and H-20 of the PJM Tariff to remove references to KPCo and AEP Kentucky Transco respectively. AEPSC also proposes to remove the revenue requirement of KPCo and AEP Kentucky Transco from the revenue requirement calculations under Attachment H-14 and H-20 of the PJM Tariff, respectively. The proposed revisions will reduce the transmission revenue requirements and resulting transmission rates under Attachment H-14 and Attachment H-20.²

AEPSC requests that the Commission issue an order accepting the proposed revisions to the Attachment H-14 and Attachment H-20 of PJM Tariff and making the proposed revisions effective on the day on which the Transaction closes. AEPSC requests all necessary waivers for the Commission to accept the revisions to the PJM Tariff and to grant the requested effective date. AEPSC also asks that the Commission issue an order in sixty days as it will assist in ensuring the Transaction can close in a timely manner.

I. DOCUMENTS SUBMITTED WITH THE FILING

In accordance with the Commission's eTariff protocols, this filing includes the following documents:

- 1. This transmittal letter;
- 2. Clean and marked versions of Attachment H-14 (Annual Transmission rates of AEP East Companies);
- 3. Clean and marked versions of Attachment H-20 (Annual Transmission Rates of AEP East Transcos);
- 4. Attachment A: Revised Calculations of the AEP East Companies Annual Update with KPCo's Revenue Requirement removed; and
- 5. Attachment B: Revised Calculations of the AEP East Transcos Annual Update with Kentucky Transco's Revenue Requirement removed.

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² Attachments A and B show the reduction in the AEP East Companies' and the AEP East Transcos' projected 2022 revenue requirements when the revenue requirements for KPCo and AEP Kentucky Transco are removed. The populated templates containing the projected 2022 revenue requirements for the AEP East Companies were filed in Docket No. ER17-405-000 on November 1, 2022. AEPSC proposes to remove the revenue requirement for KPCo but the revenue requirements for the other AEP East Companies remains unchanged. Similarly, the populated templates containing the projected 2022 revenue requirements for the AEP East Transcos were filed in Docket No. ER17-406-000 on November 1, 2022. AEPSC proposes to remove the revenue requirement for AEP Kentucky Transco but the revenue requirements for the other AEP East Transcos remain unchanged.

II. BACKGROUND

A. AEP/Liberty Transaction

On October 26, 2021, American Electric Power Company, Inc. ("AEP") announced that it entered into an agreement to sell its Kentucky operations, including KPCo and AEP Kentucky Transco, to Liberty, an indirect subsidiary of Algonquin Power & Utilities. The parties are currently pursuing the necessary regulatory approvals for the Transaction.³ The Transaction is currently expected to close in the second quarter of 2022.

B. Attachment H-14 and Attachment H-20 under the PJM Tariff

Attachment H-14 sets forth the Annual Transmission Rates for Network Integration Service for the AEP East Companies. Specifically, Attachment H-14A sets forth the AEP East Companies' formula rate implementation protocols, and Attachment H-14B sets forth the AEP East Companies' formula rate template, which is used by each of the AEP East Companies to calculate its annual transmission revenue requirement. Those individual company revenue requirements are combined to calculate the AEP East Companies' revenue requirement. Each year, AEPSC, on behalf of the AEP East Companies, submits for filing for informational purposes a true-up of their annual transmission revenue requirement for the prior year and projected annual transmission revenue requirement for the upcoming rate year pursuant to Attachment H-14.⁴

Attachment H-20 in the PJM Tariff contain the Annual Transmission Rates for Network Integration Service for AEP East Transcos. Attachment H-20A sets forth the AEP East Transcos' formula rate implementation protocols, and Attachment H-20B sets forth AEP Transcos' formula rate template, which is a blank formula rate template used by each of the AEP East Transcos in PJM to calculate its transmission revenue requirement. Those individual company revenue requirements are combined to calculate an overall revenue requirement for the AEP East Transcos. Each year, AEPSC, on behalf of the AEP East Transcos, submits for filing for informational purposes the true-up of their annual transmission revenue requirement for the prior year and projected annual transmission revenue requirement for the upcoming rate year pursuant to Attachment H-20.5

³ On December 22, 2021, the parties submitted an application in Docket No. EC22-26 seeking authorization under Section 203 of the FPA for the disposition of jurisdictional facilities associated with the Transaction. That application is currently pending before the Commission.

⁴ The Commission accepted Attachment H-14 by letter order issued on April 24, 2018. *See American Electric Power Service Corp*,. Docket No. ER17-405, Delegated Letter Order (April 24, 2018).

⁵ The Commission accepted Attachment H-20 by letter order issued on April 4, 2018. *See American Electric Power Service Corp*,. Docket No. ER17-406, Delegated Letter Order (April 24, 2018). The true-up and project revenue requirement informational filings of the AEP East Companies and AEP Transmission Companies are posted on PJM's website at https://pjm.com/markets-and-operations/billing-settlements-and-credit/formula-rates.aspx.

III. PURPOSE OF THIS FILING

The purpose of this filing is to make the necessary changes to Attachment H-14 and Attachment H-20 to reflect that after the closing of the Transaction, KPCo will no longer be affiliated with the AEP East Companies and AEP Kentucky Tranco will no longer be affiliated with the AEP East Transcos. The specific revisions proposed in this filing are discussed further below.

A. Proposed Changes to Attachment H-14

Because KPCo will no longer be affiliated with the AEP East Companies following the closing of the Transaction, AEPSC proposes to remove KPCo's transmission revenue requirement from the overall AEP East Companies' revenue requirement calculated pursuant to Attachment H-14B. Removing KPCo's revenue will reduce the AEP East Companies' revenue requirement and the AEP East Companies' transmission rate. Specifically, removing KPCo from the AEP East Companies' zonal revenue requirement will reduce the zonal revenue requirement by \$85.5 million and the transmission rate by \$3,900.65/MW-Year. Attachment A shows the new projected AEP East Companies' revenue requirement for 2022 and the projected transmission rate with the revenue requirement for KPCo removed. In addition to removing the KPCO revenue requirement, AEPSC proposes the following revisions to Attachment H-14:

- Revise the first page of Attachment H-14A (the AEP East Operating Companies' Formula Rate Implementation Protocols) to eliminate the reference to KPCo;
- Revise Worksheet O of Attachment H-14B (Calculation of Postemployment Benefits Other than Pensions ("PBOP") Expenses Allocable to Transmission Service) to remove the reference to KPCo on line 4.⁷
- Delete Worksheet P to Attachment H-14B, which sets forth KPCo's depreciation rates.

⁶ Consistent with the Protocols in Attachment H-14A, the AEP East Companies shall calculate and submit the actual 2022 net revenue requirement on or before May 25, 2023. The AEP East Companies will also submit a True-Up for the projected 2022 net revenue requirement. The True-Up will reflect the removal of KPCo on the date of closing.

⁷ The AEP East Companies do not recover actual PBOP expenses. Rather, the amount of allowable PBOP expense is determined by a settled-upon process identified on Worksheet O (PBOP Allowance). AEPSC recently filed to update the PBOP Allowance in Docket No. ER22-600-000, which is currently pending before the Commission. AEPSC will remove the KPCo pro-rata share from PBOP Allowance effective with the changes in the instant filing. By removing the KPCo PBOP Allowance and removing PBOP expenses associated with KPCo from Attachment H-14B, the proposed changes will ensure only the settled PBOP Allowance for the remaining AEP East Companies are included in the revenue requirement calculation in Attachment H-14B.

B. Proposed Changes to Attachment H-20

Because AEP Kentucky Transco will no longer be affiliated with the AEP East Transcos following the closing of the Transaction, AEPSC proposes to remove AEP Kentucky Transco's transmission revenue requirement from the overall AEP East Transcos' revenue requirement calculated pursuant to Attachment H-20B. Removing AEP Kentucky Transco's revenue will reduce the AEP East Transcos' revenue requirement and the AEP East Transcos' transmission rate. Specifically, removing AEP Kentucky Transco from the AEP revenue requirement will reduce the revenue requirement by \$15.3 million and the transmission rate by \$696.75 MW-Year. Attachment B shows the new projected AEP East Transcos' revenue requirement for 2022 and the projected transmission rate with the revenue requirement for AEP Kentucky Transco removed.⁸ In addition to removing the AEP Kentucky Transco revenue requirement, AEPSC proposes the following revisions to Attachment H-20:

- Revise Attachment H-20 to remove the reference to AEP Kentucky Transco from footnote 1.
- Revise the first page of Attachment H-20A (the AEP Transco Formula Rate Implementation Protocols) to eliminate the reference to AEP Kentucky Transco;
- Delete Worksheet P to Attachment H-20B, which sets forth AEP Kentucky's depreciation rates.⁹
- Remove the reference to Kentucky Power Company from Worksheet Q to Attachment H-20B.

IV. PROPOSED EFFECTIVE DATE AND REQUEST FOR WAIVER

AEPSC requests an effective date for the proposed changes to Attachment H-14 and Attachment H-20 to be on the day on which the Transaction is consummated, and thus is using the 12/31/9998. After the Transaction closes, AEPSC proposes that AEPSC, through PJM, inform the Commission of the consummation date through the filing of a Notice in eTariff under Filing Type Code 150 in this docket soon after consummation, so that the Commission can change the 12/31/9998 date to the appropriate effective date for the tariff record included herein.

⁸ Consistent with the Protocols in Attachment H-20A, AEP East Transcos shall calculate and submit the actual 2022 net revenue requirement on or before May 25, 2023. The AEP East Transcos will also submit a True-Up for the projected 2022 net revenue requirement. The True-Up will reflect the removal of AEP Kentucky Transco on the date of closing.

⁹ The AEP East Transcos do not recover actual PBOP expenses. Rather, the amount of allowable PBOP expense is determined per a direct labor rate calculated based on total AEP System PBOP expense in a process described on Worksheet O. Because Attachment H-20 will no longer include AEP Kentucky Transco, or any labor associated with its operations, the allowable PBOP expenses associated with AEP Kentucky Transco has been removed from the AEP East Transcos revenue requirements as shown in Attachment B. No changes to the template in Attachment H-20B were required to remove the PBOP expenses.

AEPSC requests any waivers of the Commission's regulations that may be necessary to permit the filing to become effective as requested.

Simultaneous with this filing, PJM on behalf of KPCo, and AEP Kentucky Transco also submits a Section 205 filing under which Liberty, KPCO and AEP Kentucky Transco propose to establish new stand-alone formula rates for KPCo and AEP Kentucky Transco ("Liberty Filing"). The changes in this filing and the changes in the Liberty Filing are both proposed to take effect on the day on which the Transaction closes. Thus, there will be no overlap in charges to customers. The stand-alone rates for KPCo and AEP Kentucky Transco will become effective on the same day the revenue requirements for KPCo and AEP Kentucky Transco are removed from the AEP East Companies' and the AEP East Transcos' revenue requirements and those entities' respective rates.

V. FILING REQUIREMENTS

As noted, the proposed revisions to Attachment H-14 and Attachment H-20 are intended to reflect the Transaction under which ownership over KPCo and AEP Kentucky Transmission will be transferred from AEP to Liberty. The proposed changes to Attachment H-14 remove references KPCo as an AEP East Transcos and to remove KPCo's revenue requirement from the calculation of the AEP East Companies' transmission revenue requirement under Attachment H-14. Similarly, the proposed changes to Attachment H-20 remove references to AEP Kentucky Transco as an AEP Transmission Company and to remove AEP Kentucky Transco's revenue requirement from the calculation of the AEP East Transcos' total transmission revenue requirement. The net effect of the proposed revisions is to reduce the transmission revenue requirements under Attachment H-14 and H-20, as noted above. AEPSC is not proposing any other substantive changes to the rates, terms, or conditions under the PJM Tariff. AEPSC therefore requests that the Commission accept the revised PJM Tariff for filing and, to the extent necessary, waive the requirements of 18 C.F.R. §§ 35.13(c)(1) and (2), (d), and (h).

VI. SERVICE

In accordance with the Commission's regulations, PJM has served a copy of this filing on all PJM Members and on all state utility regulatory commissions in the PJM Region by posting this filing electronically. PJM will post a copy of this filing to the FERC filings section of its internet site, located at the following link: http://www.pjm.com/documents/ferc-manuals/ferc-filings.aspx with a specific link to the newly-filed document, and will send an e-mail on the same date as this filing to all PJM Members and all state utility regulatory commissions in the PJM Region alerting them that this filing has been made by PJM and is available by following such link. If the document is not immediately available by using the referenced link, the document will be available through the referenced link within 24 hours of the filing. A copy of this filing will be available on the Commission's eLibrary website located at the following link: http://www.ferc.gov/docs-filing/elibrary.asp in accordance with the Commission's regulations and Order No. 714.

VII. COMMUNICATIONS

AEPSC requests that any correspondence or communications with respect to this filing be directed to the following:

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 $^{^{10}}$ 18 C.F.R. $\S 35.2(e)$ and 385.2010(f)(3).

VIII. CONCLUSION

AEPSC requests that the Commission issue an order accepting the proposed changes to Attachment H-14 and H-20 of the PJM Tariff and making them effective on the day on which the Transaction is consummated. AEPSC also requests that the Commission grant all necessary waivers to accept the proposed changes as proposed herein. Finally, AEPSC requests that the Commission issue an order in sixty days as it will ensure the Transaction can close in a timely manner.

Respectfully submitted,

/s/Steven J. Ross

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Counsel for American Electric Power Service Corporation

ATTACHMENT H-14A THE AEP EAST OPERATING COMPANIES FORMULA RATE IMPLEMENTATION PROTOCOLS

The formula rate template ("Template"), and these formula rate implementation protocols ("Protocols") together comprise the filed rate ("Formula Rate") of Appalachian Power Company, Indiana Michigan Power Company, Kentucky Power Company, Kingsport Power Company, Ohio Power Company, and Wheeling Power Company (collectively "AEP East Companies" or "AEP") for transmission revenue requirement determinations under the PJM Interconnection, LLC ("PJM") Open Access Transmission Tariff ("PJM Tariff"). AEP shall follow the instructions specified in the Formula Rate to calculate annually its net annual transmission revenue requirement, as set forth at Attachment H-14B, page 1, line 4 of the Template ("Net Revenue Requirement"). The Net Revenue Requirement shall be determined for January 1 to December 31 of a given calendar year (the "Rate Year"). The Formula Rate shall become effective for recovery of AEP's Net Revenue Requirement upon the effective date for incorporation into the PJM Tariff through a filing with the Federal Energy Regulatory Commission ("FERC" or "Commission") under Section 205 of the Federal Power Act ("FPA"), 16 U.S.C. § 824d.

Section 1. <u>Annual Projection</u>

a. No later than October 31 preceding a Rate Year, and each subsequent Rate Year, AEP shall determine its projected Net Revenue Requirement for the upcoming Rate Year in accordance with the Formula Rate ("Annual Projection"). The Annual Projection shall include the True-Up Adjustment described and defined in Section 2 below, if applicable. AEP shall cause an electronic version of the Annual Projection to be posted in both a Portable Document Format ("PDF") and fully-functioning Excel file at a publicly

accessible location on PJM's internet website and OASIS. The date on which the posting occurs shall be that year's "Annual Projection Publication Date."

- b. The posting of the Annual Projection shall:
 - (i) Provide the Formula Rate calculations and all inputs thereto, as well as supporting documentation and workpapers for data that are used in the projected Net Revenue Requirement;
 - (ii) Include all inputs in sufficient detail to identify the components of AEP's projected Net Revenue Requirement, explanations of the bases for the projections and input data, and sufficient detail and explanation to enable Interested Parties¹ to replicate the calculation of the projected Net Revenue Requirement;
 - (iii) With respect to any Accounting Changes (as that term is defined in Section 3.e.iii)
 - A. Identify any Accounting Changes including:
 - i. The initial implementation of an accounting standard or policy;
 - The initial implementation of accounting practices for unusual or unconventional items where FERC has not provided specific accounting direction;
 - iii. Correction of errors and prior period adjustments that impact the projected Net Revenue Requirement calculation;
 - iv. The implementation of new estimation methods or policies that change prior estimates; and

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¹ As used in these Protocols, "Interested Parties" shall include but not be limited to: (i) any Eligible Customer under the PJM Tariff; (ii) any regulatory agency with rate jurisdiction over a public utility located within the PJM footprint; (iii) any consumer advocate authorized by state law to review and contest the rates for any such public utility; and (iv) any party with standing under FPA section 205 or section 206.

- v. Changes to income tax elections;
- B. Identify items included in the projected Net Revenue Requirement at an amount other than on a historic cost basis (e.g., fair value adjustments);
- C. Identify any reorganization or merger transaction during the previous year and explain the effect of the accounting for such transaction(s) on inputs to the projected Net Revenue Requirement; and
- Provide, for each item identified pursuant to Section 1.b.iii.A C of these
 Protocols, a narrative explanation of the individual impact of such changes
 on the projected Net Revenue Requirement.
- (iv) Include the following information related to affiliate cost allocation:
 - A. A detailed description of the methodologies used to allocate and directly assign costs between AEP and its affiliates by service category or function, including any changes to such cost allocation methodologies from the prior year, and the reasons for those changes; and
 - B. The magnitude of such costs that have been allocated or directly assigned between AEP and each affiliate by service category or function.
- c. If the date for making the posting of the Annual Projection should fall on a weekend or a holiday recognized by FERC, then the posting shall be made no later than the next business day.² Within five (5) calendar days of the posting, PJM shall provide notice of such posting via the PJM Members Committee email subscription ("PJM Exploder List"). Interested Parties can subscribe to the PJM Exploder List on the PJM website.

² For the purposes of these Protocols, if any deadline included in these Protocols should fall on a weekend or a holiday recognized by FERC, then the deadline shall be extended to no later than the next business day.

- d. Together with the posting of the Annual Projection, AEP shall cause to be posted on the PJM internet website and OASIS, and distributed to the PJM Exploder List, the time, date, location, and remote-access information for a stakeholder meeting with Interested Parties in order for AEP to explain its Annual Projection and to provide Interested Parties an opportunity to seek information and clarifications regarding the Annual Projection ("Annual Projection Meeting"). The Annual Projection Meeting shall be held no less than twenty (20) business days and no more than thirty (30) business days after the posting of the Annual Projection. Notice of the Annual Projection Meeting shall be provided via the PJM Exploder List no less than seven (7) calendar days prior to the meeting. AEP will provide remote access to the Annual Projection Meeting in order to ease burdens (e.g. travel costs) to ensure all Interested Parties have the opportunity to participate.
- e. To the extent AEP agrees to make changes in the Annual Projection for a given Rate Year, such revised Annual Projection shall be promptly posted at a publicly accessible location on PJM's internet website and OASIS, and e-mailed to the PJM Exploder List. Changes posted prior to November 30 preceding the Rate Year, or the next business day if November 30 is not a business day (or such later date as can be accommodated under PJM's billing practices), shall be reflected in the Annual Projection for the Rate Year; changes posted after that date will be reflected, as appropriate, in the True-Up Adjustment for the Rate Year.
- f. The Annual Projection, including the True-Up Adjustment, for each Rate Year shall be subject to review, challenge, true-up, and refunds or surcharges with interest, to the extent and in the manner provided in these Protocols.

Section 2. <u>True-Up Adjustment</u>

AEP will calculate the amount of under- or over-collection of its actual Net Revenue Requirement during the preceding Rate Year ("True-Up Adjustment") after the FERC Form No. 1 data for that Rate Year has been filed with the Commission. The True-Up Adjustment shall be the sum of the True-Up Adjustment Over/Under Recovery as determined in Section 2(a) and the Interest on the True-Up Adjustment Over/Under Recovery as determined in Section 2(b):

a. AEP's projected Net Revenue Requirement collected during the previous Rate Year³ will be compared to AEP's actual Net Revenue Requirement for the previous Rate Year calculated in accordance with AEP's Formula Rate and based upon (i) AEP's FERC Form No. 1 for that same Rate Year, (ii) any FERC orders specifically applicable to AEP's calculation of its annual revenue requirement, (iii) the books and records of AEP (which shall be maintained consistent with the FERC Uniform System of Accounts ("USofA")), (iv) FERC accounting policies and practices applicable to the calculation of annual revenue requirements under formula rates, and (v) any aspects of the PJM Tariff Governing Documents that apply to the calculation of annual revenue requirements under

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If the initial use of this Formula Rate covers only part of a calendar year, the initial projected annual Net Revenue Requirement will be divided by 12 to calculate the monthly projected cost of service to be collected each month it is effective that first year. Similarly, the actual Net Revenue Requirement will be divided by 12 to calculate the actual monthly cost of service to be collected during those same months of that year. Similar calculations of projected Net Revenue Requirement and actual Net Revenue Requirement will be made for the months prior to the effective date of this Formula Rate using the previous formula rate in effect during those months. The actual Net Revenue Requirements computed under each of the two formula rate periods that initial Rate Year will be added together to obtain the total actual Net Revenue Requirement. The first True-up Adjustment will compare this total actual Net Revenue Requirement to the Net Revenue Requirement collected under the two formulas for that initial Rate Year.

- individual transmission owner formula rates,⁴ to determine any over- or under-recovery ("True-Up Adjustment Over/Under Recovery").
- b. Interest on any True-Up Adjustment Over/Under Recovery shall be calculated for the thirty-six (36) months during which the over or under recovery in the revenue requirement remains outstanding (*i.e.*, from January 1 of the Rate Year being trued-up through December 31 of the year in which the True-Up Adjustment Over/Under recovery is credited or collected). The interest rate to be applied to the True-Up Adjustment Over/Under Recovery amounts will be determined using the average monthly FERC Interest Rate (as determined pursuant to 18 C.F.R. § 35.19a) for the twenty (20) months from the beginning of the Rate Year being trued-up through August 31 of the following year.

Section 3. Annual Update

- a. On or before May 25 following each Rate Year, AEP shall calculate its actual Net Revenue Requirement and the True-Up Adjustment as described in Section 2 ("Annual Update") for such Rate Year and, together with such other information described in this Section 3, shall cause such Annual Update to be posted, in both a PDF and fully-functioning Excel format, at a publicly accessible location on PJM's internet website and OASIS. Within five (5) calendar days of such posting, PJM shall provide notice of such posting via the PJM Exploder List.
- b. If the date for making the Annual Update posting should fall on a weekend or a holiday recognized by the FERC, then the posting shall be due on the next business day.

⁴ PJM Tariff Governing Documents include the PJM Tariff, Bylaws, Criteria, and Membership Agreements.

- c. The date on which the posting occurs shall be that year's "Annual Update Publication

 Date."
- d. Together with the posting of the Annual Update, AEP shall cause to be posted on the PJM website and OASIS the time, date, location, and remote-access information for a stakeholder meeting with Interested Parties in order for AEP to explain its Annual Update and to provide Interested Parties an opportunity to seek information and clarifications regarding the Annual Update ("Annual Update Meeting"). Notice of the Annual Update Meeting shall be provided via the PJM Exploder List no less than seven (7) calendar days prior to the meeting. The Annual Update Meeting shall be held no less than twenty (20) business days and no more than thirty (30) business days after the Annual Update Publication Date. AEP will provide remote access to the Annual Update Meeting in order to ease burdens (e.g. travel costs) to ensure all Interested Parties have the opportunity to participate.
- e. The Annual Update posting for the Rate Year:
 - (i) Shall provide, via the Formula Rate worksheets, sufficiently detailed supporting documentation for data (and all adjustments thereto or allocations thereof) used in the Formula Rate that are not stated in the FERC Form No. 1;⁵

⁵ It is the intent of the Formula Rate, including the supporting explanations and allocations described therein, that each input to the Formula Rate for purposes of determining the actual Net Revenue Requirement for a given Rate Year will be either taken directly from the FERC Form No. 1 or reconcilable to the FERC Form No. 1 by the application of clearly identified and supported information. If the referenced form is superseded, the successor form(s) shall be utilized and supplemented as necessary to provide equivalent information as that provided in the superseded form. If the referenced form is discontinued, equivalent information as that provided in the discontinued form shall be utilized.

- (ii) Shall provide sufficient detail and sufficient explanation to enable Interested

 Parties to replicate the calculation of the Annual Update results from the FERC

 Form No. 1 and verify that each input to the Template is consistent with the requirements of the Formula Rate;
- (iii) Shall identify:
 - A. Any change in accounting that affects inputs to the Template or the resulting charges billed under the Formula Rate ("Accounting Change"), including:
 - i. The initial implementation of an accounting standard or policy;
 - The initial implementation of accounting practices for unusual or unconventional items where FERC has not provided specific accounting direction;
 - iii. Correction of errors and prior period adjustments that impact theTrue-Up Adjustment calculation;
 - iv. The implementation of new estimation methods or policies that change prior estimates; and
 - v. Changes to income tax elections;
 - B. Any items included in the Annual Update at an amount other than on a historic cost basis (e.g., fair value adjustments);
 - C. Any reorganization or merger transaction during the previous year and an explanation of the effect of the accounting for such transaction(s) on inputs to the Annual Update;

- D. For each item identified pursuant to Sections 3.e.iii.A C of these
 Protocols, the individual impact (in narrative format) of such changes on the Annual Update.
- (iv) Shall be subject to review and challenge in accordance with the procedures set forth in Sections 4, 5, and 6 of these Protocols.
- (v) Shall be subject to review and challenge in accordance with the procedures set forth in these Protocols with respect to the prudence of any costs and expenditures included for recovery in the Annual Update; provided, however, that nothing in these Protocols is intended to modify the Commission's applicable precedent with respect to the burden of going forward or burden of proof under formula rates in such prudence challenges; and
- (vi) Shall not seek to modify the Formula Rate and shall not be subject to challenge by any Interested Party seeking to modify the Formula Rate (i.e., any modifications to the Formula Rate will require, as applicable, an FPA section 205 or section 206 filing or initiation of a section 206 investigation).
- f. The following Formula Rate inputs shall be stated values to be used in the Formula Rate until changed pursuant to an FPA section 205 or section 206 proceeding: (i) rate of return on common equity ("ROE"); (ii) the depreciation and/or amortization rates as set forth in Attachment 10 to the Formula Rate template, and (iii) Post-Employment benefits other than Pension ("PBOP") charges pursuant to Statement of Financial Accounting Standards No. 106, Employers' Accounting for Postretirement Benefits Other Than Pensions.

g. Example – Timelines for 2018 Annual Projection and 2019 Annual Update:

On or before October 31, 2017, AEP will determine the projected Net Revenue

Requirement for the 2018 Rate Year. AEP will post the Annual Projection for the 2018

Rate Year in accordance with Section 1 above. On or before May 25, 2019, AEP will

post its Annual Update, consisting of the actual Net Revenue Requirement and True-Up

Adjustment for the 2018 Rate Year determined pursuant to Section 2 above. Such True-Up Adjustment will be reflected in the Annual Projection of the Net Revenue

Requirement for the 2020 Rate Year posted on or before October 31, 2019.

Section 4. Annual Review Procedures

Each Annual Update and Annual Projection shall be subject to the following review procedures ("Annual Review Procedures"):

a. Interested Parties shall have up to the later of two-hundred-ten (210) calendar days after the applicable Publication Date, or thirty (30) calendar days after the receipt of all responses to timely submitted information requests (unless such period is extended with the written consent of AEP or by FERC order) ("Review Period"), to review the calculations and to notify AEP in writing of any specific challenges to the Annual Update or Annual Projection ("Preliminary Challenge"), including challenges related to Accounting Changes. An Interested Party submitting a Preliminary Challenge must specify the inputs, supporting explanations, allocations, calculations, or other information to which it objects, and provide an appropriate explanation and documents to support its challenge. AEP shall cause to be posted all Preliminary Challenges at a

- publicly accessible location on PJM's internet website and OASIS, and a link to the website will be e-mailed to the PJM Exploder List.
- b. In the event of a Preliminary Challenge, AEP will appoint a senior representative to work with the Interested Party (or its representatives) toward a resolution of the dispute.
- c. AEP shall respond in writing to a Preliminary Challenge within twenty (20) business days of receipt, and its response shall notify the challenging party of the extent to which AEP agrees or disagrees with the challenge. If AEP disagrees with the Preliminary Challenge, it will provide the Interested Party with an explanation supporting the challenged inputs, explanations, allocations, calculations, or other information. AEP shall promptly cause to be posted its responses to all Preliminary Challenges at a publicly accessible location on PJM's internet website and OASIS, and a link to the website will be e-mailed to the PJM Exploder List. Notwithstanding the foregoing, Preliminary Challenges and responses to Preliminary Challenges that include material deemed by AEP to be confidential information will not be publicly posted but will be made available to requesting parties pursuant to a confidentiality agreement to be executed by AEP and the requesting party.
- d. AEP shall respond to all Preliminary Challenges submitted during the Review Period by no later than thirty (30) calendar days after the end of the Review Period.
- e. Interested Parties shall have up to one-hundred-fifty (150) calendar days after each annual Publication Date (unless such period is extended with the written consent of AEP or by FERC order) to serve reasonable information requests on AEP ("Discovery Period").

- f. Information requests shall be limited to what is necessary to determine: (i) the extent, effect, or impact of an Accounting Change; (ii) whether the Annual Update or Annual Projection fails to include data properly recorded in accordance with the Protocols; (iii) the proper application of the Template and procedures in the Protocols; (iv) the accuracy of data and consistency with the Formula Rate of the charges shown in the Annual Update or Annual Projection; (v) the prudence of the actual costs and expenditures, including procurement methods and cost control methodologies; (vi) the effect of any change to the underlying USofA or FERC Form No. 1; and (vii) any other information that may reasonably have substantive effect on the calculation of the charge pursuant to the Formula Rate. The information requests shall not otherwise be directed to ascertaining whether the Formula Rate is just and reasonable. Information requests shall not solicit information concerning costs or allocations where the costs or allocation methods have been determined to be appropriate by FERC in the context of prior AEP Annual Updates, except that such information requests shall be permitted if they (i) seek to determine if there has been a change in circumstances, (ii) are in connection with corrections pursuant to Section 6 of these Protocols, or (iii) relate to costs or allocations that have not previously been challenged and adjudicated by FERC.
- g. AEP shall make a good faith effort to respond to reasonable information requests pertaining to the Annual Update or Annual Projection within fifteen (15) business days of receipt of such requests. AEP shall respond to all reasonable information requests no later than thirty (30) calendar days after the end of the Discovery Period. AEP will cause to be posted on the PJM website and OASIS all information requests from Interested Parties and AEP's response(s) to such requests, and a link to the website will be e-mailed

to the PJM Exploder List. Notwithstanding the foregoing, information and document requests and responses to information and document requests that include material deemed by AEP to be confidential information will not be publicly posted but will be made available to requesting parties pursuant to a confidentiality agreement to be executed by AEP and the requesting party. Voluminous materials will be made available at a physical AEP site.

- h. AEP shall not claim that responses to information and document requests provided pursuant to these Protocols are subject to any settlement privilege in any subsequent FERC proceeding addressing AEP's Annual Update or Annual Projection.
- i. To the extent AEP and any Interested Party(ies) are unable to resolve disputes related to information requests submitted in accordance with these Annual Review Procedures, AEP or the Interested Party may petition the FERC to appoint an Administrative Law Judge as a discovery master to resolve the discovery dispute(s) in accordance with these Protocols and consistent with the FERC's discovery rules.
- j. Preliminary Challenges or Formal Challenges (as described in Sections 4 and 5) related to Accounting Changes shall be treated in the same manner under these Protocols as other challenges to the Annual Update or Annual Projection. Failure to make a Preliminary Challenge with respect to an Accounting Change in an Annual Update or Annual Projection shall not act as a bar with respect to a Formal Challenge with respect to that Annual Update or Annual Projection provided that the Interested Party submitted a Preliminary Challenge with respect to one or more other issues. Nor shall such failure bar a subsequent Preliminary Challenge related to a subsequent Annual Update or

- Annual Projection to the extent such Accounting Change affects the subsequent Annual Update or Annual Projection.
- k. If a change made by AEP to its accounting policies, practices, or procedures, or the application of the Formula Rate, is found by the FERC to be unjust, unreasonable, or unduly discriminatory or preferential, then the calculation of the charges to be assessed during the Rate Year then under review, and the charges to be assessed during any subsequent Rate Years, including any True-up Adjustments, shall not include such change, but shall include any remedy that may be prescribed by FERC in the exercise of its discretion as of the effective date of such remedy, to ensure that the Formula Rate continues to operate in a manner that is just, reasonable, and not unduly discriminatory or preferential.

Section 5. Resolution of Challenges

- a. Interested Parties shall have up to two-hundred-seventy (270) days following the applicable Publication Date (unless such period is extended with the written consent of AEP or by FERC order), to file a challenge with the FERC ("Formal Challenge"). Such Formal Challenge shall be submitted in the same docket as the AEP informational filing and shall be served on AEP by electronic service on the date of such filing in accordance with Section 385.2010(f)(3) of the Commission's regulations. Subject to any applicable confidentiality and Critical Energy Infrastructure Information restrictions, all information and correspondence produced by AEP pursuant to these Protocols may be included in any Formal Challenge or other FERC proceeding relating to the Formula Rate.
- b. Formal Challenges are to be filed pursuant to these Protocols, rather than under rule 206, and shall:
 - (i) Clearly identify the action or inaction which is alleged to violate the Formula Rate Template or Protocols;
 - (ii) Explain how the action or inaction violates the filed rate Template or Protocols;
 - (iii) Set forth the business, commercial, economic or other issues presented by the action or inaction as such relate to or affect the party filing the Formal Challenge, including
 - A. The extent or effect of an Accounting Change;
 - B. Whether the Annual Update or Annual Projection fails to include data properly recorded in accordance with these Protocols;

- C. The proper application of the Template and procedures in these Protocols;
- D. The accuracy of the data and consistency with the Formula Rate of the charges shown in the Annual Update or Annual Projection;
- E. The prudence of actual costs and expenditures;
- F. The effect of any change to the underlying Uniform System of Accounts or the FERC Form No. 1; or
- G. Any other information that may reasonably have substantive effect on the calculation of the charge pursuant to the Template.
- (iv) Make a good faith effort to quantify the financial impact or burden (if any) created for the party filing the Formal Challenge as a result of the action or inaction;
- (v) State whether the issues presented are pending in an existing Commission proceeding or a proceeding in any other forum in which the filing party is a party, and if so, provide an explanation why timely resolution cannot be achieved in that forum;
- (vi) State the specific relief or remedy requested, including any request for stay or extension of time, and the basis for that relief;
- (vii) Include all documents that support the facts in the Formal Challenge in possession of, or otherwise attainable by, the filing party, including, but not limited to, contracts and affidavits; and

- (viii) State whether the filing party utilized the Preliminary Challenge procedures described in these Protocols to dispute the action or inaction raised by the Formal Challenge, and, if not, describe why not.
- c. Preliminary and Formal Challenges shall be limited to issues that may be necessary to determine: (i) the extent or effect of an Accounting Change; (ii) whether the Annual Update or Annual Projection fails to include data properly recorded in accordance with these Protocols; (iii) the proper application of the Formula Rate and procedures in these Protocols; (iv) the accuracy of data and consistency with the Formula Rate of the calculations shown in the Annual Update and Annual Projection; (v) the prudence of actual costs and expenditures; (vi) the effect of any change to the underlying Uniform System of Accounts or FERC Form No. 1; or (vii) any other information that may reasonably have substantive effect on the calculation of the charge pursuant to the formula.
- d. Failure to raise an issue in a Preliminary Challenge shall not bar an Interested Party from raising that issue in a Formal Challenge, provided the Interested Party submitted a Preliminary Challenge during the Review Period with respect to one or more other issues. Failure to pursue an issue through a Preliminary Challenge or to lodge a Formal Challenge regarding any issue as to a given Annual Update shall bar pursuit of such issue with respect to that Annual Update, but shall not bar pursuit of such issue or the lodging of a Formal Challenge as to such issue as it relates to a subsequent Annual Update.

- e. Any response by AEP to a Formal Challenge must be submitted to the FERC within thirty (30) calendar days of the date of the filing of the Formal Challenge, and shall be served on the filing party(ies) and the PJM Exploder List on the date of such filing.
- f. In any Formal Challenge proceeding concerning an Annual Update (including corrections), Annual Projection, or Accounting Change(s), AEP shall demonstrate the justness and reasonableness of the rate resulting from its application of the Formula Rate by demonstrating that it has correctly applied the terms of the Formula Rate consistent with these Protocols and that it followed the applicable requirements and procedures in applying the Formula Rate. Nothing herein is intended to alter the burdens applied by FERC with respect to prudence challenges.
- g. Except as specifically provided herein, nothing herein shall be deemed to limit in any way the right of AEP to file unilaterally, pursuant to section 205 of the FPA and the regulations thereunder, an application seeking changes to the Formula Rate or to any of the stated value inputs requiring a section 205 filing under these Protocols (including, but not limited to, ROE and depreciation and amortization rates), or the right of any other party or the Commission to seek such changes pursuant to section 206 of the FPA and the regulations thereunder.
- h. AEP may, at its discretion and at a time of its choosing, make a limited filing pursuant to section 205 to modify stated values in the Formula Rate (i) for amortization and depreciation rates, (ii) to correct obvious errors or omissions in the Formula Rate such as would result from changes to the FERC Form No. 1, or (iii) PBOP charges pursuant to Statement of Financial Accounting Standards No. 106, Employers' Accounting for Postretirement Benefits Other Than Pensions. The sole issue in any such limited

section 205 proceeding shall be whether such proposed change(s) is just and reasonable, and it shall not address other aspects of the Formula Rate or impose upon AEP any burden with respect to such other aspects of the Formula Rate.

Section 6. <u>Changes to Annual Updates</u>

If AEP determines or concedes that corrections to the Annual Update are required, whether under Sections 4 or 5 of these Protocols, including but not limited to those requiring corrections to its FERC Form No. 1, or input data used for a Rate Year that would have affected the Annual Update for that Rate Year, such corrections shall be reflected as adjustments in the Annual Update for the next Rate Year, with interest calculated in accordance with the FERC Interest Rate (as determined pursuant to 18 C.F.R. § 35.19a). This reconciliation mechanism shall apply in lieu of mid-Rate Year adjustments.

AEP East Companies

Cost of Service Formula Rate Using Actual/Projected FF1 Balances Worksheet G Supporting - Development of Composite State Income Tax Rate COMPANY NAME HERE

State #1 Tax Rate Apportionment Factor - Note 1 Effective State Tax Rate	0.00%
State #2 Tax Rate	
Apportionment Factor - Note 1	
Effective State Tax Rate	0.00%
State #3 Tax Rate	
Apportionment Factor - Note 1	
Effective State Tax Rate	0.00%
State #4 Tax Rate	
Apportionment Factor - Note 1	
Effective State Tax Rate	0.00%
Total Effective State Income Tax Rate	0.00%

Apportionment Factors are determined as part of the Company's annual tax return for that jurisdiction.

COM	IPANY NAME HERE					
	(A)	(B)	(C)	(D)	(E)	(F)
Line		Total	D	T -1	041	Nian Allandia
No.	Account	Company NOTE 1	Property	Labor	Other	Non-Allocable
1	Revenue Taxes	NOTE				
2	List Individual Taxes Here	-				-
3	Real Estate and Personal Property Taxes					
4	Real and Personal Property - Jurisdiction #1	-	-			
5	Real and Personal Property - Jurisdiction #2	-	-			
6	Real and Personal Property - Jurisdiction #3	-	-			
7	Real and Personal Property - Other Jurisdictions	-	-			
8	Payroll Taxes					
9 10	Federal Insurance Contribution (FICA) Federal Unemployment Tax	-		-		
11	State Unemployment Insurance	<u>-</u>		-		
12	Production Taxes					
13	List Individual Taxes Here	-				-
14		-				-
15	Miscellaneous Taxes					
16	List Individual Taxes Here	-				-
17		-			-	
18 19		-			-	
20		- -			-	
21		-				-
22		=				-
23						
24	Total Taxes by Allocable Basis					<u>-</u>
	(Total Company Amount Ties to FFI p.114, Ln 14,(c))	d EEDGE	4 1 1 177	a II 1		
	NOTE 1: The detail of each total company number and its source in	n the FERC Form	l I is shown on W	S H-1.		
	Functional Property Tax Allocation	Production	Transmsission	Distribution	General	Total
25	Functionalized Net Plant (TCOS, Lns 41 thru 46)	<u>110ddctioii</u>	-	-	- General	<u>10tai</u>
	STATE JURISDICTION #1					
26	Percentage of Plant in STATE JURISDICTION #1					
27	Net Plant in STATE JURISDICTION #1 (Ln 25 * Ln 26)	-	-	-	-	-
28	Less: Net Value of Exempted Generation Plant					
29 30	Taxable Property Basis (Ln 27 - Ln 28) Relative Valuation Factor	-	-	-	-	-
31	Weighted Net Plant (Ln 29 * Ln 30)	_	_	_		
32	General Plant Allocator (Ln 31 / (Total - General Plant))	0.00%	0.00%	0.00%	-100.00%	
33	Functionalized General Plant (Ln 32 * General Plant)	-	-	-	-	-
34	Weighted STATE JURISDICTION #1 Plant (Ln 31 + 33)	- 0.000/	- 0.000/	- 0.000/	-	-
35	Functional Percentage (Ln 34/Total Ln 34) STATE JURISDICTION #2	0.00%	0.00%	0.00%		
36	Percentage of Plant in STATE JURISDICTION #2					
37	Net Plant in STATE JURISDICTION #2 (Ln 25 * Ln 36)	-	-	-	-	-
38	Less: Net Value of Exempted Generation Plant					
39	Taxable Property Basis (Ln 37 - Ln 38)	-	-	-	-	-
40	Relative Valuation Factor					
41	Weighted Net Plant (Ln 39 * Ln 40)	0.00%	0.00%	0.000/	100.000/	
42 43	General Plant Allocator (Ln 41 / (Total - General Plant)) Functionalized General Plant (Ln 42 * General Plant)	0.00%	0.00%	0.00%	-100.00%	
44	Weighted STATE JURISDICTION #2 Plant (Ln 41 + 43)	-	-	_	_	_
45	Functional Percentage (Ln 44/Total Ln 44)	0.00%	0.00%	0.00%		
	STATE JURISDICTION #3					
46	Net Plant in STATE JURISDICTION #3 (Ln 25 - Ln 27 - Ln 37)	-	-	-	-	-
47	Less: Net Value Exempted Generation Plant					
48 49	Taxable Property Basis Relative Valuation Factor	-	-	-	-	-
50	Weighted Net Plant (Ln 48 * Ln 49)	-	-	-	_	
51	General Plant Allocator (Ln 50 / (Total - General Plant)	0.00%	0.00%	0.00%	-100.00%	
52	Functionalized General Plant (Ln 52 * General Plant)	-	-	-	-	
52	` '					
53 54	Weighted STATE JURISDICTION #3 Plant (Ln 50 + 52) Functional Percentage (Ln 53/Total Ln 53)	0.00%	0.00%	0.00%	-	-
J -T	1 anonomia i crochiago (Eli 33/10tai Eli 33)	0.0070	0.0070	0.0070		

AEP East Companies

Cost of Service Formula Rate Using 2008 FF1 Balances

Worksheet H-1 Form 1 Source Reference of Company Amounts on WS H $\,$

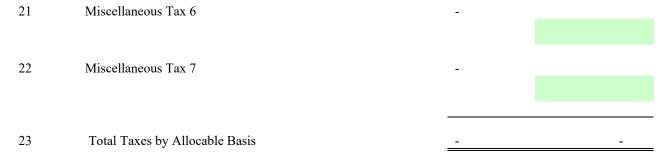
(A)

	(11)		(D)	(C)	(D)		
Li ne No			Total	FERC FORM 1	FERC FORM 1		
•	Annual Tax Expenses by Type (Note 1)		Company	Tie-Back	Reference		
1	Revenue Taxes						
2	Revenue Tax 1						
	<u>(A)</u>	(B)	(C)	(D)	(E)	(F) Tax	(G) Transmis
	Real Estate and Personal Propety Tax Detail Annual Tax Expenses by Type (Note 1)	Tax Year	Total Company	FERC FORM 1 Tie-Back	FERC FORM 1 Reference	Year Factor (Note 2)	sion Function (Note 2)
3	Real Estate and Personal Property Taxes Total (Ln 4 + Ln 5 + Ln 6 + Ln 7)		<u>-</u>	_			-
4	Real and Personal Property - Jurisdiction 1		i e				-
5	Real and Personal Property – Jurisdiction 2						
6	Real and Personal Property – Jurisdiction 3						
7	Real and Personal Property - Other Jurisdictions		r i				-
Li ne	<u>(A)</u>		(B)	(C)	(D)		
No	Annual Tax Expense by Type (Note 1)		Total Company	FERC FORM 1 Tie-Back	FERC Form 1 Reference		
8	Payroll Taxes						
9	Federal Insurance Contribution (FICA)		-				
10	Federal Unemployment Tax		-				
11	State Unemployment Insurance		-				
12	<u>Production Taxes</u>						
13	Production Tax 1		-				
15	Miscellaneous Taxes						
16	Miscellaneous Tax 1		-				
17	Miscellaneous Tax 2		-				
18	Miscellaneous Tax 3		-				
19	Miscellaneous Tax 4		-				
20	Miscellaneous Tax 5		-				

(B)

(C)

(D)



(Total Company Amount Ties to FFI p.114, Ln 14,(c))

Note 1: The taxes assessed on each operating company can differ from year to year and between operating companies by both the type of taxes and the states in which they were assessed. Therefore, for each company, the types and jurisdictions of tax expense recorded on this page could differ from the same page in the same company's prior year template or from this page in other operating companies' current year templates. For each update, this sheet will be revised to ensure that the total activity recorded hereon equals the total reported in account 408.1 on P. 114, Ln 14 of the FERC Form 1.

Note 2: The transmission functional amounts for any Real Estate and Property taxes listed on pages 263 of the FERC Form 1 will be allocated using the transmission functional allocator calculated for each state in Worksheet H of the applicable year that the taxes were assesed. Real and Personal Property - Other Jurisdictions will be allocated using the Gross Plant Allocator from the applicable year.

AEP East Companies

Cost of Service Formula Rate Using Actual/Projected FF1 Balances

Worksheet I RESERVED FOR FUTURE USE

AEP East Companies

Cost of Service Formula Rate Using Actual/Projected FF1 Balances

Worksheet J Supporting Calculation of PROJECTED PJM RTEP Project Revenue Requirement Billed to Benefiting Zones COMPANY NAME HERE

I. Calculate Return and Income Taxes with basis point ROE increase for Projects Qualified for Regional Billing.

Α.	Determine 'R'	with hypothetical	basis point increase	in ROE for Identified Projects
----	----------------------	-------------------	----------------------	--------------------------------

ROE w/o incentives (TCOS, ln 156)	0.00%
Project ROE Incentive Adder	
ROE with additional basis point incentive	0.00%

Determine R (cost of long term debt, cost of preferred stock and equity percentage is from the TCOS, lns 154 through 156)

	<u>%</u>	<u>Cost</u>	Weighted cost
Long Term Debt	0.00%	0.00%	0.000%
Preferred Stock	0.00%	0.00%	0.000%
Common Stock	0.00%	0.00%	0.000%
		R	= 0.000%

В.	Determine Return using	'R' with	hypothetical	basis point	t ROE increase	for Identified Projects.

Rate Base (TCOS, In 68)	-
R (from A. above)	0.000%
Return (Rate Base x R)	-

C. Determine Income Taxes using Return with hypothetical basis point ROE increase for Identified Projects.

C. Determine theome taxes using Keturn with hypothetical basis point KOE mercase for fuentified riojects.		
Return (from B. above)		-
Effective Tax Rate (TCOS, ln 114)		0.00%
Income Tax Calculation (Return x CIT)	-	
ITC Adjustment	-	
Excess Deferred Income Tax	-	
Tax Affect of Permanent Differences	-	
Income Taxes	-	

II. Calculate Net Plant Carrying Charge Rate (Fixed Charge Rate or FCR) with hypothetical basis point ROE increase.

A. Determine Annual Revenue Requirement less return and Income Taxes.

Annual Revenue Requirement (TCOS, ln 1)

Lease Payments (TCOS, 95) Return (TCOS, ln 126)

Income Taxes (TCOS, ln 125)	=
Annual Revenue Requirement, Less Lease Payments, Return and Taxes	
B. Determine Annual Revenue Requirement with hypothetical basis point increase in ROE.	
Annual Revenue Requirement, Less Lease payments, Return and Taxes	-
Return (from I.B. above)	-
Income Taxes (from I.C. above)	=
Annual Revenue Requirement, with Basis Point ROE increase	-
Depreciation (TCOS, ln 100)	=
Annual Rev. Req, w/ Basis Point ROE increase, less Depreciation	-
C. Determine ECD with howethetical basis maint DOE increases	

C. Determine FCR with hypothetical basis point ROE increase.

Incremental FCR with Basis Point ROE increase, less Depreciation

Net Transmission Plant (TCOS, ln 42)	-
Annual Revenue Requirement, with Basis Point ROE increase	-
FCR with Basis Point increase in ROE	
Annual Rev. Req, w / Basis Point ROE increase, less Dep.	-
FCR with Basis Point ROE increase, less Depreciation	
FCR less Depreciation (TCOS, ln 10)	

III Calculation of Composite Depreciation Rate

SUMMARY OF PROJECTED ANNUAL RTEP REVENUE REQUIREMENTS					
		Rev Require	W Incentives	Incentive Amounts	
	PROJECTED YEAR	Projected	Year -	- \$ -	

0.00%

0.00%

0.00%

0.00%

Page 25

Average Transmission Plant Balance for Rate Year (TCOS, ln 21)

Annual Depreciation and Amortization Expense (TCOS, ln 100)

Composite Depreciation Rate

Depreciable Life for Composite Depreciation Rate

Round to nearest whole year

- 4

Worksheet J - ATRR PROJECTED Calculation for PJM Projects Charged to Benefiting Zones

IV. Determine the Revenue Requirement, and Additional Revenue Requirement for facilities receiving incentives.

Facilities receiving incentives accepted by FERC in Docket No.				(e.g. ER05-925-000)			Current Projected Year ARR - Current Projected Year ARR w/ Incentive -			
Project Description:					Current Projected Year Incentive ARR -					
Details										
Investment	Current Year								IISTORY OF PROJECTED ANNUAL NUE REQUIREMENTS:	
						Trojecteu Teur		CUMULATIVE HISTORY OF PROJECTED ANNUAL		
Service Year (yyyy)		ROE increase accepted by FERC (Basis Points)				-	REVENUE REQUIREMENTS:			
Service Month (1-12)		FCR w/o incentives, less depreciation				0.00%				
Useful life - FCR w/incentives approved for these facilities, les				s dep.		0.00%	FROM EACH PRIOR YEAR TEMPLATE BELOW TO MAINTA			
CIAC (Yes or No) Annual Depreciation Expense				<u>-</u>			HISTORY OF PROJECTED ARRS OVER THE LIFE OF THE PROJECT.			
		•					RTEP Projected Rev. Req't.From	RTEP Projected Rev. Req't.From		
Investment	Beginning	Depreciation	Ending	RTEP Rev. Req't.	RTEP Rev. Req't.	Incentive Rev.	Prior Year Template w/o	Prior Year Template with Incentives		
Year	Balance	Expense	Balance	w/o Incentives	with Incentives **	Requirement ##	Incentives	**		
-	=	-	-	=	-	-				

^{**} This is the total amount that needs to be reported to PJM for billing to all regions.

Project Totals

This is the calculation of additional incentive revenue on projects deemed by the FERC to be eligible for an incentive return. This additional incentive requirement is applicable for the life of this specific project. Each year the revenue requirement calculated for PJM should be incremented by the amount of the incentive revenue calculated for that year on this project.

In order to calculate the proper monthly RTEP billing amount, PJM requires a 12 month revenue requirement for each RTEP project. As a result, notwithstanding the fact that the project was in service for a partial year, the project revenue requirement in the year that the project goes into service has been annualized (shown at the full-year level) so that PJM will collect the correct monthly billings.

Sout of Bervie Formula rate Compression 11 Formula 11 F					
Worksheet K Supporting Calculation of TRUE-UP PJM RTEP Project Revenue Requirement Billed	to Benefiting	g Zones			
COMPANY NAME HERE					
. Calculate Return and Income Taxes with basis point ROE increase for Projects Qualified	for Regiona	l Billing.			
A. Determine 'R' with hypothetical basis point increase in ROE for Identified Projects	Ö	O			
ROE w/o incentives (TCOS, ln 156)		0.00%			
Project ROE Incentive Adder					
ROE with additional basis point incentive		0.00%			
Determine R (cost of long term debt, cost of preferred s	stock and equ	ity percentage	e is from the TCC)S, lns 1.	54 through 156)
		<u>%</u>	<u>Cost</u>	<u>Weig</u>	ghted cost
Long Te	erm Debt	0.00%	0.00%		0.000%
Preferr	ed Stock	0.00%	0.00%		0.000%
Comm	on Stock	0.00%	0.00%		0.000%
]	R =	0.000%
B. Determine Return using 'R' with hypothetical basis point ROE increase for Identified	Projects.				
Rate Base (TCOS, ln 68)	-		-		
R (from A. above)			0.00	0%	

C. Determine Income Taxes using Return with hypothetical basis point ROE increase for Identified Projects.

Return (from B. above) Effective Tax Rate (TCOS, ln 114) 0.00%

Income Tax Calculation (Return x CIT) ITC Adjustment Excess Deferred Income Tax Tax Affect of Permanent Differences Income Taxes

II. Calculate Net Plant Carrying Charge Rate (Fixed Charge Rate or FCR) with hypothetical basis point ROE increase.

A. Determine Annual Revenue Requirement less return and Income Taxes.

Annual Revenue Requirement (TCOS, ln 1) Lease Payments (TCOS, Ln 95) Return (TCOS, ln 126)

Annual Revenue Requirement, Less Lease Payments, Return and Taxes

B. Determine Annual Revenue Requirement with hypothetical basis point increase in ROE.

Annual Revenue Requirement, Less Lease Payments, Return and Taxes

Return (from I.B. above)

Income Taxes (from I.C. above)

Income Taxes (TCOS, ln 125)

Annual Revenue Requirement, with Basis Point ROE increase

Depreciation (TCOS, ln 100)

Return (Rate Base x R)

Annual Rev. Req, w/ Basis Point ROE increase, less Depreciation

C. Determine FCR with hypothetical basis point ROE increase.

Net Transmission Plant (TCOS, ln 42)

Annual Revenue Requirement, with Basis Point ROE increase

FCR with Basis Point increase in ROE

Annual Rev. Req, w / Basis Point ROE increase, less Dep.

FCR with Basis Point ROE increase, less Depreciation

FCR less Depreciation (TCOS, ln 10)

Incremental FCR with Basis Point ROE increase, less Depreciation

III. Calculation of Composite Depreciation Rate

Average Transmission Plant Balance for Rate Year (TCOS, ln 21)

Annual Depreciation and Amortization Expense (TCOS, ln 100)

Composite Depreciation Rate

Depreciable Life for Composite Depreciation Rate

Round to nearest whole year

Page 1 of 2

SUMMARY OF TRUED-UP ANNUAL REVENUE REQUIREMENTS FOR RTEP PROJECTS Rev Require W Incentives Incentive Amounts TRUE-UP YEAR Historic Year As Projected in Prior Year WS J Actual after True-up \$ -True-up of ARR For Historic Year -0.00%0.00% 0.00%

0.00%

0.00%

COMPANY NAME HERE Worksheet K - ATRR TRUE-UP Calculation for PJM Projects Charged to Benefiting Zones

IV. Determine the Revenue Requirement, and Additional Revenue Requirement for facilities receiving incentives.

A. Base Plan Facilities

Facilities	receiving	incentives	accented	hy FI	FRC in	Docket N	J
racinues	receiving	mcentives	accepted	DYFI		DUCKEL I	w.

(e.g. ER05-925-000)

Project Description:

Details							
Investment		Current Year					Historic Year
Service Year (yyyy)			epted by FERC (Ba	sis Points)			_
Service Month (1-12)		FCR w/o incentive depreciation		C 1177 1			0.00%
Useful life	_	dep.	w/incentives approved for these facilities, less				
CIAC (Yes or No)	No	Annual Depreciati	annual Depreciation Expense				-
Investment Year	Beginning Balance	Depreciation Expense	Ending Balance	Average Balance	RTEP Rev. Req't. w/o Incentives	RTEP Rev. Req't. with Incentives	Incentive Rev. Requirement ##
-	-	-	-	-	-	-	\$ - \$

Project Totals - - - -

This is the calculation of additional incentive revenue on projects deemed by the FERC to be eligible for an incentive return. This

additional incentive requirement is applicable for the life of this specific project. Each year the revenue requirement calculated for PJM

should be incremented by the amount of the incentive revenue calculated for that year on this project.

Page 2 of 2

Rev Require	W Incentives	Incentive Amounts
-	-	-
_		-
	•	1

TRUE UP OF PROJECT REVENUE REQUIREMENT FOR PRIOR YEAR:

CUMULATIVE HISTORY OF TRUED-UP ANNUAL REVENUE REQUIREMENTS:

INPUT TRUE-UP ARR (WITH & WITHOUT INCENTIVES) FROM EACH PRIOR YEAR TEMPLATE BELOW TO MAINTAIN HISTORY OF TRUED-UP ARRS OVER THE LIFE OF THE PROJECT.

RTEP Projected Rev. Req't.From Prior Year WS J w/o Incentives	RTEP Rev Req't True-up w/o Incentives	RTEP Projected Rev. Req't.From Prior Year WS J with Incentives **	RTEP Rev Req't True-up with Incentives **	True-up of Incentive with Incentives **
	\$ - \$		\$ -	\$ -

^{**} This is the total amount that needs to be reported to PJM for billing to all regions.

AEP East Companies Cost of Service Formula Rate Using Actual/Projected FF1 Balances Worksheet L COMPANY NAME HERE

RESERVED FOR FUTURE USE

AEP East Companies

Cost of Service Formula Rate Using Actual/Projected FF1 Balances Worksheet M Supporting Calculation of Capital Structure and Weighted Average Cost of Capital Company Name

		Average Balance of Common Equity				
Lin e No	Month	Proprietary Capital	Less: Preferred Stock	Less Undistributed Sub Earnings (Acct 216.1)	Less AOCI (Acct 219.1)	Average Balance of Common Equity (f)=(b)-(c)-(d)-(
	(a)	(b)	(c)	(d)	(e)	e)
	(Note A)	(FF1 112.16)	(FF1 250-251)	(FF1 112.12)	(FF1 112.15)	
1	December Prior to Rate Year					-
2	January					-
3	February					-
4	March					-
5	April					-
6	May					-
7	June					-
8	July					-
9	August					-
10	September October					-
11 12	November					-
13	December of Rate Year					-
14	Average of the 13 Monthly Balances	-	-	-	-	_

					e of Long Term l	Debt	
Lin e No	Month	Acct 221 Bonds	Less: Acct 222 Reacquired Bonds	Acct 223 LT Advances from Assoc. Companies	Acct 224 Senior Unsecured Notes	Less: Fair Value Hedges	Gross Proceeds Outstanding Long- Term Debt (g)=(b)-(c)+(d)+(e)-
	(a)	(b)	(c)	(d)	(e)	(f)	(f)
	(Note A) December Prior to Rate	(FF1 112.18)	(FF1 112.19)	(FF1 112.20)	(FF1 112.21)	FF1, page 257, Col. (h) - Note 1	
15	Year						-
16	January						-
17	February						-
18	March						-
19	April						-
20	May						-
21	June						-
22	July						-
23	August						-
24	September						-
25	October						-
26	November						-
27	December of Rate Year						-
28	Average of the 13 Monthly Balances	-	-	-	-	-	-

NOTE 1: The balance of fair value hedges on outstanding long term debt are to be excluded from the balance of long term debt included in the formula's capital structure. (Page 257 Column H of the FF1)

Development of Cost of Long Term Debt Based on Average Outstanding Balance

	(a)	(b)	(c)	(d)	(e)	(f)	(g)
29	Annual Interest Expense for 2017						
	Interest on Long Term Debt - Accts						
30	221 - 224 (256-257.33.i)						
	Less: Total Hedge Gain/Expense Accumu	ılated from p					
	256-257, col. (i) of FERC Form 1 include	ed in Ln 30					
31	and shown in 50 below.			-			
	Plus: Allowed Hedge Recovery From						
32	Ln 55 below.			-			
	Amort of Debt Discount & Expense -						
33	Acct 428 (117.63.c)						
	Amort of Loss on Reacquired Debt -						
34	Acct 428.1 (117.64.c)						
	Less: Amort of Premium on Debt -						
35	Acct 429 (117.65.c)						
	Less: Amort of Gain on Reacquired Debt	- Acct 429.1					
36	(117.66.c)						
	Total Interest Expense (Ln 30 - 31 +						
37	33 + 34 - 35 - 36)			-			
	Average Cost of Debt for 2017 (Ln]		
38	37/ ln 28 (g))			#DIV/0!			

CALCULATION OF RECOVERABLE HEDGE GAINS/LOSSES

NOTE: The net amount of hedging gains or losses recorded in account 427 to be recovered in this formula rate should be limited to the effective portion of pre-issuance cash flow hedges that are amortized over the life of the underlying debt issuances. The recovery of a net loss or passback of a net gain will be limited to five basis points of the total Capital Structure. Amounts related to the ineffective portion of pre-issuance hedges, cash settlements of fair value hedges issued on Long Term Debt, post-issuance cash flow hedges, and cash flow hedges of variable rate debt issuances are not recoverable in this formula and are to be recorded in the "Excludable" column below.

Amortization Period

	HEDGE AMOUNTS BY ISSUANCE (FROM p. 256-257 (i) of the FERC Form 1)	Total Hedge (Gain)/Loss for 2017	Excludable Amounts (See NOTE on Line 39)	Net Includable Hedge Amount	Remaining Unamortized Balance	Begin ning	Ending
40				-			
41				-			
42				-			
43				-			
44				-			
45				-			
46				-			
47				-			
48				-			
49					. -		
50	Total Hedge Amortization	-	-				
	Hedge Gain or Loss Prior to Application	of Recovery					
51	Limit (Sum of Lines 40 to 48) Total Average Capital Structure	·		-			
52	Balance for 2017 (TCOS, Ln 157) Financial Hedge Recovery Limit - Five	Rasis Points		-			
53	of Total Capital	Dusis I Onits		0.0005			
54	Limit of Recoverable Amount	aan af I n 51		-	1		
55	Recoverable Hedge Amortization (Les or Ln 54)	ser of Ln 51		-			
Dev	velopment of Cost of Preferred						

Development of Cost of Preferred

Stock

	Preferred Stock				Average
	0% Series - 0 - Dividend Rate (p. 250-				
56	251)		0.000%	0.000%	
			\$	\$	
57	0% Series - 0 - Par Value (p. 250-251)		-	-	
58	0% Series - 0 - Shares O/S (p.250-251)	-	-		
	0% Series - 0 - Monetary Value (Ln 57				
59	* Ln 58)	-	-		-

60	0% Series - 0 - Dividend Amount (Ln 56 * Ln 59)		
61	0% Series - 0 - Dividend Rate (p. 250-251)	0.000% \$	0.000%
62	0% Series - 0 - Par Value (p. 250-251)	φ -	-
63	0% Series - 0 - Shares O/S (p.250-251) 0% Series - 0 - Monetary Value (Ln 62	-	-
64	* Ln 63)	-	_
65	0% Series - 0 - Dividend Amount (Ln 61 * Ln 64)	-	_
66	0% Series - 0 - Dividend Rate (p. 250-251)	0.000%	0.000%
67	0% Series - 0 - Par Value (p. 250-251)	\$ -	\$ -
68	0% Series - 0 - Shares O/S (p.250-251) 0% Series - 0 - Monetary Value (Ln 67	-	-
69	* Ln 68)	-	_
70	0% Series - 0 - Dividend Amount (Ln 66 * Ln 69)	-	-

71 Balance of Preferred Stock (Lns 59, 64, 69) _ - _ -

(..., . , . ,

72 Dividends on Preferred Stock (Lns 60, 65, 70)

73 Average Cost of Preferred Stock (Ln 72/71)

-		-		-	
_		_			
	0.00%		0.00%		0.00%

Year End Total Agrees to FF1 p.112, Ln 3, col (c) & (d)

AEP East Companies

Cost of Service Formula Rate Using Actual/Projected FF1 Balances

Worksheet N - Gains (Losses) on Sales of Plant Held For Future Use

Note: Gain or loss on plant held for future are recorded in accounts 411.6 or 411.7 respectively. Sales will be functionalized based on the description of that asset. Sales of transmission assets will be direct assigned; sales of general assets will be functionalized on labor. Sales of plant held for future use related to generation or distribution will not be included in the formula.

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
Line	Date	Property Description	Function (T) or (G) T = Transmission	Basis	Proceeds	(Gain) / Loss	Functional Allocator	Functionalized Proceeds (Gain) / Loss	FERC Account
			G = General						
1						-	0.000%	-	
2						<u>-</u>	0.000%	_	
3						-	0.000%	-	
4				Net (Gain) or Loss f	or Rate Year	-	_ =	-	

AEP East Companies

Cost of Service Formula Rate Using Actual/Projected FF1 Balances

Worksheet O - Calculation of Postemployment Benefits Other than Pensions Expenses Allocable to Transmission Service

COMPANY NAME HERE

1 Total AEP East Operating Company PBOP Settlement Amount

Allocation of PBOP Settlement Amount for Rate Year:

Total Company Amount

Line#	Company	Actual Expense (Including AEPSC Billed OPEB)	Ratio of Company Actual to Total	Allocation of PBOB Recovery Allowance	Labor Allocator for Rate Year	Actual Expense	Allowable Expense	One Year Functional Expense (Over)/Under
		(A) (Line 14)	(B)=(A)/Total (A)	(C)=(B)*1	(D)	(E)=(A) * (D)	(F)=(C)*(D)	(G)=(E)-(F)
2	APCo		0.00%	-		-	-	-
3	I&M		0.00%	-		-	-	-
4	KPCo	-	0.00%		-			
<u>4</u> 5	KNGP		0.00%	-		-	-	-
<u>5</u> 6	OPCo		0.00%	-		-	-	-
<u>6</u> 7	WPCo		0.00% _	-				<u> </u>
<u>7</u> 8	Sum of Lines 2 to 67	-		-		-	-	-
	Detail of Actual PBOP Expenses to b	oe Removed in Cost of Service						

		<u>APCo</u>	<u>I&M</u>	KPCo	<u>KNGSPT</u>	<u>OPCo</u>	<u>WPCo</u>	<u>Total</u>
<u>89</u> Direct C	Charged PBOP Expense per Actuarial Report							-
Addition	onal PBOP Ledger Entries							
<u>9</u> 10 (from C	Company Records)							
1011 Medicar	are Subsidy							-
<u>11</u> 12 Net Con	mpany Expense (Ln $89 + \text{Ln } 910 + \text{Ln } 1011$)	-	-	-	-	-	-	-
<u>12</u> 13 PBOP E	Expenses From AEP Service Corporation (from Company							-
Records								
								_
<u>13</u> <u>14</u> Compar	ny PBOP Expense (Ln <u>11</u> 12 + Ln <u>12</u> 13)	-	-	-	-	-	=	

Note:

For the rate year 2017 and adjusted every four years thereafter, using the annual actuarial report produced for that year, filed as part of the informational filing, Worksheet O will be used to adjust PBOP costs for the next four years (i.e. 2017, 2018, 2019, 2020). If the annual actuarial report projects PBOP costs during the next four years, taken together with the then current cumulative PBOP cost/allowance position, will, absent a change in the PBOP allowance, cause the AEP Companies to over or under collect their cumulative PBOP costs by more than 20% of the projected next four year's total cost, the PBOP allowance shall be adjusted. Worksheet O will be used in the process of updating the PBOP allowance determining (a) the level of cumulative over or under collections during the period since the PBOP allowance was last set, including carrying costs based on the weighted average cost of capital ("WACC") each year from the formula actual rate; (b) the cumulative net present value of projected PBOP costs during the next four years, as estimated by the then current actuarial report, assuming a discount rate equal to the actual formula rate WACC for the prior calendar year; and (c) the cumulative net present value of continued collections over the next four years based on the then effective PBOP allowance, assuming a discount rate equal to the prior year WACC. If the absolute value of (a)+(b)-(c) exceeds 20% of (b), then the PBOP allowance used in the formula rate calculation shall be changed to the value that will cause the projected result of (a)+(b)+(c) to equal zero. If the projected over or under collection during the next four years will be less than 20% over the subsequent four-year period, AEP shall make a filing under FPA Section 205 to change the PBOP expense stated in the formula rate shown on Worksheet O. No other changes to the formula rate may be included in that filing.

AEP EAST COMPANIES

Worksheet - P CALCULATION OF

TOTAL WEIGHTED AVERAGE DEPRECIATION RATES

AEP East

FOR TRANSMISSION PLANT PROPERTY ACCOUNT

EFFECTIVE AS OF 3/6/2019

FOR MULTIPLE JURISDICTION COMPANIES

APPALACHIAN POWER COMPANY

		VIRO	GINIA			WES	ST VIRGINIA			FERC WI	HOLESALE	FE	RC KING	GSPORT		COMPANY
		(1)				(2)				(3)		(4)				
			WTD AVG	. PSC	OF WV		WTD AVG.			WTD AVO	.	W	TD AVG		WTD AVG.	
PLANT	VA SCC	ALLOCATION	DEPREC.	APPF	ROVED	ALLOCATION	DEPREC.	FERC	ALLOCATION	DEPREC.	. FERC	ALLOC	ATION	DEPREC.	DEPREC.	
ACCT.	RATES	FACTOR (5)	RATE	RA	TES	FACTOR (5)	RATE	RATES	FACTOR (5)	RATE	RATES	FACTO	OR (5)	RATE	RATE	_
TRANSMISSION PLANT																
Land Rights - Va.	350. 1 0.66	% 1.000000 (0.66%												0.66%	
Energy Storage Equipment		351.0				14.22%	1.000000	14.22%							14.22%	
Structures & Improvements	1	351.0		0.492648	0. 76%	1.62%	0.414603	0.67%	2.19%	0.033874	0.07%	2.19%	0.05887	74 0.13%	1.63%	
-	5	353.0		0.492648	0. 76%	2.37%	0.414603	0.07%	2.19%	0.033874	0.07%	2.19%	0.05887		2.14%	
Station Equipment																
Towers & Fixtures		354.0		0.492648	0.56%	1.59%	0.414603	.0.66%	2.19%	0.033874	0.07%	2.19%	0.05887		1.42%	
Poles & Fixtures		355.0	2.77%	0.492648 049264	1.36%	2.71%	0.414603	1.12%	2.19%	0.033874	0.07%	2.19%	0.05887	74 0.13%	2.68%	
Overhead Conductor		356.0	1.01%	8	0.50%	1.53%	0.414603	.0.63%	2.19%	0.033874	0.07%	2.19%	0.05887	74 0.13%	1.33%	
Underground Conduit		357.0	1.23%	0.492648	0.61%	3.71%	0.414603	1.54%	2.19%	0.033874	0.07%	2.19%	0.05887	74 0.13%	2.35%	
Underground Conductors		358.0	3.18%	0.492648	1.57%	5.24%	0.414603	2.17%	2.19%	0.033874	0.07%	2.19%	0.05887	74 0.13%	3.94%	
GENERAL PLANT																
Structures and Improvement	nts	390.0	1.50%	0.519557	0.78%	1.91%	0.425935	0.81%	3.43%	0.019780	0.07%	3.43%	0.03472	28 0.12%	1.78%	
Office Furniture and Equip		391.0	2.78%	0.519557	1.44%	3.17%	0.425935	1.35%	3.43%	0.019780	0.07%	3.43%	0.03472	28 0.12%	2.98%	
Transportation Equipment		392.0	0.00%	0.519557	0.00%	3.40%	0.425935	1.45%	3.43%	0.019780	0.07%	3.43%	0.03472	28 0.12%	1.64%	
Stores Equipment		393.0	1.60%	0.519557	0.83%	1.80%	0.425935	0.77%	3.43%	0.019780	0.07%	3.43%	0.03472	28 0.12%	1.79%	
Tools, Shop and Garage		204.0	2.070/	0.510557	1 000/	2.570/	0.425025	1 000/	2.420/	0.010700	0.070/	2 420/	0.02.470	0 0 1 207	2.260/	
Equipment		394.0		0.519557	1.08%	2.57%	0.425935	1.09%	3.43%	0.019780	0.07%	3.43%	0.03472		2.36%	
Laboratory Equipment		395.0		0.519557	0.79%	4.01%	0.425935	1.71%	3.43%	0.019780	0.07%	3.43%	0.03472		2.69%	
Power Operated Equipmen		396.0		0.519557	0.00%	3.90%	0.425935	1.66%	3.43%	0.019780	0.07%	3.43%	0.03472		1.85%	
Communications Equipmen	nt	397.0		0.519557	1.70%	4.98%	0.425935	2.12%	3.43%	0.019780	0.07%	3.43%	0.03472		4.01%	
Micellaneous Equipment		398.0	2.51%	0.519557	1.30%	2.70%	0.425935	1.15%	3.43%	0.019780	0.07%	3.43%	0.03472	28 0.12%	2.64%	

(1) As approved in VA Case No. PUE 2011-00037 on Nov. 30, 2011. Depreciation rates were made effective on February 1, 2012.

(4) Approved by FERC March 2, 1990 in Docket ER90-133

(3) 132

Approved by FERC March 2, 1990 in Docket ER90-

GENERAL NOTES:

⁽²⁾ Approved by PSC of WV Order dated February 27, 2019 in Case No. 18-0645-E-D effective March 6, 2019.

⁽⁵⁾ The demand allocation factors are updated annually as of January 1, based on the 12 monthly CP's as of the previous September 30th.

⁽⁶⁾ Energy Storage Equipment is a new account established per FERC Order 784.

The rates for each AEP company have been approved by their respective regulatory commissions.

APCo falls under the authority of Virginia, West Virginia and the FERC. Therefore, APCo's rates are a composite of the jurisdictions under which it operates. Each jurisdictions to derive the composite rate for the company.

AEP will make a 205 filing whenever a company's rates are changed by their commission(s), or if the methodology to calculate the jurisdictional allocator in multiple-state companies changes. Changes in the allocation factors will not necessitate a 205 filing.

Worksheet - P CALCULATION OF

TOTAL WEIGHTED AVERAGE DEPRECIATION RATES FOR TRANSMISSION PLANT PROPERTY ACCOUNT

EFFECTIVE AS OF March 11, 2020

FOR MULTIPLE JURISDICTION COMPANIES

INDIANA MICHIGAN POWER COMPANY

					INDIANA MICH	DIANA MICHIGAN POWER COMPANY					
			INDIANA		MICHIGAN				FERC WHOLESAL	TOTAL COMPANY	
		(1)			(2)			(3)			
				WTD AVG.	MPSC		WTD AVG.			WTD AVG.	WTD AVG.
	PLANT	IURC	ALLOCATION	DEPREC.	APPROVED	ALLOCATION	DEPREC.	FERC	ALLOCATION	DEPREC.	DEPREC.
	ACCT.	RATES	FACTOR (4)	RATE	RATES	FACTOR (4)	RATE	RATES	FACTOR (4)	RATE	RATE
TRANSMISSION PLANT			, ,			· ,					
Land Improvements Structures &	350.1	1.66%	0.6623353	1.0995%	1.62%	0.3376647	0.5470%	1.62%	0.3376647	0.5470%	1.65%
Improvements	352.0	1.77%	0.6623353	1.1723%	1.74%	0.3376647	0.5875%	1.74%	0.3376647	0.5875%	1.76%
Station Equipment	353.0	2.43%	0.6623353	1.6095%	2.41%	0.3376647	0.8138%	2.41%	0.3376647	0.8138%	2.42%
Towers & Fixtures	354.0	2.57%	0.6623353	1.7022%	2.45%	0.3376647	0.8273%	2,45%	0.3376647	0.8273%	2.53%
Poles & Fixtures	355.0	3.19%	0.6623353	2.1128%	3.17%	0.3376647	1.0704%	3.17%	0.3376647	1.0704%	3.18%
Overhead Conductors	356.0	2.35%	0.6623353	1.5565%	2.28%	0.3376647	0.7699%	2.28%	0.3376647	0.7699%	2.33%
Underground Conduit Underground	357.0	2.30%	0.6623353	1.5234%	2.21%	0.3376647	0.7462%	2.21%	0.3376647	0.7462%	2.27%
Conductors	358.0	1.93%	0.6623353	1.2783%	1.90%	0.3376647	0.6416%	1.90%	0.3376647	0.6416%	1.92%
Trails & Roads	359.0	1.61%	0.6623353	1.0664%	1.59%	0.3376647	0.5369%	1.59%	0.3376647	0.5369%	1.60%
GENERAL PLANT Structures and			0.6818683								
Improvements Office Furniture and	390.0	2.08%	0.6818683	1.4183%	2.08%	0.3181317 0.3181317	0.6617%	2.08%	0.3181317	0.6617%	2.08%
Equip. Transportation	391.0	4.79%	0.6818683	3.2661%	4.84%	0.3181317	1.5398%	4.84%	0.3181317	1.5398%	4.81%
Equipment	392.0	4.64%	0.6010602	3.1639%	4.68%	0.2101217	1.4889%	4.68%	0.3181317	1.4889%	4.65%
Stores Equipment Tools, Shop and	393.0	7.35%	0.6818683 0.6818683	5.0117%	7.38%	0.3181317 0.3181317	2.3478%	7.38%	0.3181317	2.3478%	7.36%
Garage Equipment Laboratory	394.0	6.99%	0.6818683	4.7663%	7.07%	0.3181317	2.2492%	7.07%	0.3181317	2.2492%	7.02%
Equipment Power Operated	395.0	5.41%	0.6818683	3.6889%	5.46%	0.3181317	1.7370%	5.46%	0.3181317	1.7370%	5.43%
Equipment Communications	396.0	4.81%	0.6818683	3.2798%	4.90%	0.3181317	1.5588%	4.90%	0.3181317	1.5588%	4.84%
Equipment Micellaneous	397.0	3.91%	0.6818683	2.6661%	3.93%	0.3181317	1.2503%	3.93%	0.3181317	1.2503%	3.92%
Equipment	398.0	3.32%		2.2638%	3.35%		1.0657%	3.35%	0.3181317	1.0657%	3.33%

⁽¹⁾ As approved in Indiana Cause No. 45235 effective March 11, 2020.

⁽²⁾ As approved in Michigan Case No. U-20359 effective February 1, 2020.

- (3) FERC wholesale formula rate agreements specify that the depreciation rates in the formula rates change upon approval of MPSC rates in the Michigan jurisdiction.
- (4) The rates approved for each jurisdiction are updated when approved by that commission. These demand-based allocation factors for all jurisdictions are updated when new rates are approved in one of the jurisdictions. These allocation factors reflect I&M's 12 monthly Coincident Peaks during test year of the most recent rate case.

GENERAL NOTES:

The rates for each AEP company have been approved by their respective regulatory commissions.

I&M falls under the authority of Indiana, Michigan and the FERC. Therefore, I&M's rates are a composite of the jurisdictions under which it operates. Each jurisdictions' rate is multiplied by an allocation factor, and the product for each jurisdiction is added with the other jurisdictions to derive the composite rate for the company.

AEP will make a 205 filing whenever a company's rates are changed by their commission(s), or if the methodology to calculate the jurisdictional allocator in multiple-state companies changes. Changes in the allocation factors will not necessitate a 205 filing.

AEP EAST COMPANIES PJM FORMULA RATE

WORKSHEET P - TRANSMISSION DEPRECIATION RATES

EFFECTIVE AS OF 9/1/2016

FOR SINGLE JURISDICTION COMPANIES

KINGSPORT POWER COMPANY

	PLANT	
	ACCT.	RATES
		Note 1
TRANSMISSION PLANT		
Structures & Improvements	352.0	1.04%
Station Equipment	353.0	1.49%
Towers & Fixtures	354.0	0.12%
Poles & Fixtures	355.0	2.14%
Overhead Conductors	356.0	0.77%
Underground Conduit	357.0	Note 2
Underground Conductors	358.0	Note 2
Composite Transmission Depreciation Rate		1.46%
GENERAL PLANT		
Structures & Improvements	390.0	1.71%
Office Furniture & Equipment	391.0	2.82%
Stores Equipment	393.0	2.22%
Tools Shop & Garage Equipment	394.0	3.12%
Laboratory Equipment	395.0	3.17%
Communication Equipment	397.0	3.32%
Miscellaneous Equipment	398.0	4.92%

Total General Plant 3.25%

Reference:

Note 1: Rates Approved In Tennessee Regulatory Authority Docket No. 16-00001.

Note 2: Kingsport Power Company does not have investment in plant accounts 357 or 358. Therefore, there are no depreciation rates approved for these plant accounts.

General Note
AEP will make a 205 filing whenever a company's rates are changed by their commission(s), or if the methodology to calculate the jurisdictional allocator in multiple-state companies changes. Changes in the allocation factors will not necessitate a 205 filing.

PJM FORMULA RATE

WORKSHEET P - TRANSMISSION DEPRECIATION RATES

EFFECTIVE AS OF 7/1/2015

FOR SINGLE JURISDICTION COMPANIES KENTUCKY POWER COMPANY

PLANT

	ACCT.	RATES	
		Note 1	
TRANSMISSION PLANT	-		
Land Rights	350.1	1.44%	
-Structures & Improvements	352.0	2.08%	
-Station Equipment	353.0	2.15%	
Towers & Fixtures	354.0	2.61%	
Poles & Fixtures	355.0	3.95%	
-Overhead Conductors	356.0	2.91%	
-Underground Conduit	357.0	2.99%	
- Underground Conductors	358.0	2.62%	
-GENERAL PLANT			
-Land and Land Rights	389.1	1.59%	
-Structures and Improvements	390.0	3.97%	
-Office Furniture and Equip.	391.0	3.20%	
-Transportation Equipment	392.0	3.52%	
-Stores Equipment	393.0	4.15%	
-Tools, Shop and Garage Equipment	394.0	4.20%	
Laboratory Equipment	395.0	5.76%	
-Power Operated Equipment	396.0	5.43%	
-Communications Equipment	397.0	5.66%	
- Micellaneous Equipment	398.0	6.73%	

Reference:

Note 1: Rates Approved in Kentucky Public Service Commission Case No. 2014 00396.

General Note:

AEP will make a 205 filing whenever a company's rates are changed by their commission(s), or if the methodology to calculate the jurisdictional allocator in multiple state companies changes. Changes in the allocation factors will not necessitate a 205 filing.

PJM FORMULA RATE

WORKSHEET P - TRANSMISSION DEPRECIATION RATES

EFFECTIVE AS OF 1/1/2012

FOR SINGLE JURISDICTION COMPANIES

OHIO POWER COMPANY

		RATES
	PLANT	Note 1
	ACCT.	
TRANSMISSION PLANT (Note 1)		
Structures & Improvements	352.0	2.02%
Station Equipment	353.0	2.29%
Twrs and Fixtures Above 69 KV	354.0	1.88%
Twrs and Fixtures Below 69 KV	354.0	1.88%
Poles and Fixtures Above 69 KV	355.0	3.52%
Poles and Fixtures Below 69 KV	355.0	3.52%
Overhead Conductor & Devices Above 69KV	356.0	1.91%
Overhead Conductor & Devices MSP	356.0	1.91%
Overhead Conductor & Devices 138KV/Above	356.0	1.91%
Overhead Conductor & Devices 69KV/Below	356.0	1.91%
Overhead Conductor & Devices CLR 69KV/Below	356.0	1.91%
Underground Conduit	357.0	2.26%
Underground Conductors	358.0	3.27%
GENERAL PLANT (Note 2)		
Structures and Improvements	390.0	2.17%
Office Furniture and Equip.	391.0	3.33%
Transportation Equipment	392.0	2.00%
Stores Equipment	393.0	2.94%
Tools, Shop and Garage Equipment	394.0	3.53%
Laboratory Equipment	395.0	3.57%
Power Operated Equipment	396.0	3.85%
Communications Equipment	397.0	2.86%
AMI - Communications Equipment	397.16	6.67%
Micellaneous Equipment	398.0	4.00%

Reference:

Note 1: These are the weighted average of the depreciation rates in effect for Columbus Southern Power and Ohio Power prior to the merger of Columbus Southern into Ohio

Power.

Note 2: General Plant depreciation rates were updated as a result of the order issued in Cases No 16-1852-EL-SSO and 16-1853-EL-SSO.

General Note:

AEP will make a 205 filing whenever a company's rates are changed by their commission(s), or if the methodology to calculate the jurisdictional allocator in multiple-state companies changes. Changes in the allocation factors will not necessitate a 205 filing.

PJM FORMULA RATE

WORKSHEET P - TRANSMISSION DEPRECIATION RATES

EFFECTIVE AS OF 3/6/2019

FOR SINGLE JURISDICTION COMPANIES

WHEELING POWER COMPANY

	PLANT	
	ACCT.	RATES
		Note 1
TRANSMISSION PLANT		
Structures & Improvements	352.0	1.15%
Station Equipment	353.0	2.22%
Towers & Fixtures	354.0	2.65%
Poles & Fixtures	355.0	2.41%
Overhead Conductors	356.0	1.32%
Underground Conduit	357.0	9.94%
Underground Conductors	358.0	13.98%
Trails & Roads	359.0	-
GENERAL PLANT		
Structures and Improvements	390.0	1.08%
Office Furniture and Equip.	391.0	2.13%
Stores Equipment	393.0	1.78%
Tools, Shop and Garage Equipment	394.0	1.65.%
Communications Equipment	397.0	5.09%
Micellaneous Equipment	398.0	2.76%

Note 1: Rates Approved in WV Public Service Commission Case No. 18-0645-E-D.

General Note:

AEP will make a 205 filing whenever a company's rates are changed by their commission(s), or if the methodology to calculate the jurisdictional allocator in multiple-state companies changes. Changes in the allocation factors will not necessitate a 205 filing.

AEP East Companies Cost of Service Formula Rate Using Actual/Projected FF1 Balances Worksheet Q – True-up With Interest (Hypothetical Example)

Reconciliation Revenue Requirement For Year 2018 Available May 25, 2019 2018 Revenue Requirement Forecast by October 31, 2017 True-up Adjustment -Over (Under) Recovery

Interest Rate on Amount of Refund	s or Surcharges (Note 1)	Over (Under) Recovery Plus Interest	Average Monthly Interest Rate 0.2780%	Months	Calculated Interest	Amortization	Surcharge (Refund) Owed
An over or under collection will be	recovered prorata over 2	018, held for 2019 and returned	prorata over 2020				
<u>Calculation of Interest</u>	V 2010		0.27909/	12	Monthly		
January February	Year 2018 Year 2018	- -	0.2780% 0.2780%	12 11	-		-
March	Year 2018	-	0.2780%	10	-		_
April	Year 2018	-	0.2780%	9	-		-
May	Year 2018	-	0.2780%	8 7	-		-
June July	Year 2018 Year 2018	-	0.2780% 0.2780%	6	-		-
August	Year 2018	=	0.2780%	5	_		-
September	Year 2018	-	0.2780%	4	-		-
October	Year 2018	-	0.2780%	3	-		-
November	Year 2018	- -	0.2780%	2	-		-
December	Year 2018	-	0.2780%	1 -	-	•	
					Annual		
January through December	Year 2019	-	0.2780%	12	-		-
Over (Under) Recovery Plus Interes	st Amortized and Recove	ered Over 12 Months	0.2780%		Monthly	-	-
·		-			-	-	-
February	Year 2020	-	0.2780%		-	-	-
March	Year 2020	-	0.2780%		-	-	-
April May	Year 2020 Year 2020	-	0.2780% 0.2780%		-	-	-
June	Year 2020	-	0.2780%		-	-	-
July	Year 2020	-	0.2780%		-	-	-
August	Year 2020	-	0.2780%		-	-	-
September	Year 2020	-	0.2780%		-	-	-
October	Year 2020	-	0.2780%		-	-	-
November	Year 2020	-	0.2780%		-	-	-
December	Year 2020	-	0.2780%		-	-	-
				-	-	•	
True-Up Adjustment with Interest						-	
Less Over (Under) Recovery						-	
Less Over (Olider) Recovery						_	

Note 1: The interest rate to be applied to the over recovery or under recovery amounts will be determined using the average monthly FERC interest rate (as determined pursuant to 18 C.F.R. section 35.19a) for the twenty (20) months from the beginning of the rate year being trued-up through August 31 of the following year.

ATTACHMENT H-14A THE AEP EAST OPERATING COMPANIES FORMULA RATE IMPLEMENTATION PROTOCOLS

The formula rate template ("Template"), and these formula rate implementation protocols ("Protocols") together comprise the filed rate ("Formula Rate") of Appalachian Power Company, Indiana Michigan Power Company, Kingsport Power Company, Ohio Power Company, and Wheeling Power Company (collectively "AEP East Companies" or "AEP") for transmission revenue requirement determinations under the PJM Interconnection, LLC ("PJM") Open Access Transmission Tariff ("PJM Tariff"). AEP shall follow the instructions specified in the Formula Rate to calculate annually its net annual transmission revenue requirement, as set forth at Attachment H-14B, page 1, line 4 of the Template ("Net Revenue Requirement"). The Net Revenue Requirement shall be determined for January 1 to December 31 of a given calendar year (the "Rate Year"). The Formula Rate shall become effective for recovery of AEP's Net Revenue Requirement upon the effective date for incorporation into the PJM Tariff through a filing with the Federal Energy Regulatory Commission ("FERC" or "Commission") under Section 205 of the Federal Power Act ("FPA"), 16 U.S.C. § 824d.

Section 1. Annual Projection

a. No later than October 31 preceding a Rate Year, and each subsequent Rate Year, AEP shall determine its projected Net Revenue Requirement for the upcoming Rate Year in accordance with the Formula Rate ("Annual Projection"). The Annual Projection shall include the True-Up Adjustment described and defined in Section 2 below, if applicable. AEP shall cause an electronic version of the Annual Projection to be posted in both a Portable Document Format ("PDF") and fully-functioning Excel file at a publicly accessible location on PJM's internet website and OASIS. The date on which the posting occurs shall be that year's "Annual Projection Publication Date."

- b. The posting of the Annual Projection shall:
 - (i) Provide the Formula Rate calculations and all inputs thereto, as well as supporting documentation and workpapers for data that are used in the projected Net Revenue Requirement;
 - (ii) Include all inputs in sufficient detail to identify the components of AEP's projected Net Revenue Requirement, explanations of the bases for the projections and input data, and sufficient detail and explanation to enable Interested Parties¹ to replicate the calculation of the projected Net Revenue Requirement;
 - (iii) With respect to any Accounting Changes (as that term is defined in Section 3.e.iii)
 - A. Identify any Accounting Changes including:
 - i. The initial implementation of an accounting standard or policy;
 - The initial implementation of accounting practices for unusual or unconventional items where FERC has not provided specific accounting direction;
 - iii. Correction of errors and prior period adjustments that impact the projected Net Revenue Requirement calculation;
 - iv. The implementation of new estimation methods or policies that change prior estimates; and
 - v. Changes to income tax elections;

¹ As used in these Protocols, "Interested Parties" shall include but not be limited to: (i) any Eligible Customer under the PJM Tariff; (ii) any regulatory agency with rate jurisdiction over a public utility located within the PJM footprint; (iii) any consumer advocate authorized by state law to review and contest the rates for any such public utility; and (iv) any party with standing under FPA section 205 or section 206.

- B. Identify items included in the projected Net Revenue Requirement at an amount other than on a historic cost basis (e.g., fair value adjustments);
- C. Identify any reorganization or merger transaction during the previous year and explain the effect of the accounting for such transaction(s) on inputs to the projected Net Revenue Requirement; and
- Provide, for each item identified pursuant to Section 1.b.iii.A C of these
 Protocols, a narrative explanation of the individual impact of such changes
 on the projected Net Revenue Requirement.
- (iv) Include the following information related to affiliate cost allocation:
 - A. A detailed description of the methodologies used to allocate and directly assign costs between AEP and its affiliates by service category or function, including any changes to such cost allocation methodologies from the prior year, and the reasons for those changes; and
 - B. The magnitude of such costs that have been allocated or directly assigned between AEP and each affiliate by service category or function.
- c. If the date for making the posting of the Annual Projection should fall on a weekend or a holiday recognized by FERC, then the posting shall be made no later than the next business day.² Within five (5) calendar days of the posting, PJM shall provide notice of such posting via the PJM Members Committee email subscription ("PJM Exploder List"). Interested Parties can subscribe to the PJM Exploder List on the PJM website.

² For the purposes of these Protocols, if any deadline included in these Protocols should fall on a weekend or a holiday recognized by FERC, then the deadline shall be extended to no later than the next business day.

- d. Together with the posting of the Annual Projection, AEP shall cause to be posted on the PJM internet website and OASIS, and distributed to the PJM Exploder List, the time, date, location, and remote-access information for a stakeholder meeting with Interested Parties in order for AEP to explain its Annual Projection and to provide Interested Parties an opportunity to seek information and clarifications regarding the Annual Projection ("Annual Projection Meeting"). The Annual Projection Meeting shall be held no less than twenty (20) business days and no more than thirty (30) business days after the posting of the Annual Projection. Notice of the Annual Projection Meeting shall be provided via the PJM Exploder List no less than seven (7) calendar days prior to the meeting. AEP will provide remote access to the Annual Projection Meeting in order to ease burdens (e.g. travel costs) to ensure all Interested Parties have the opportunity to participate.
- e. To the extent AEP agrees to make changes in the Annual Projection for a given Rate Year, such revised Annual Projection shall be promptly posted at a publicly accessible location on PJM's internet website and OASIS, and e-mailed to the PJM Exploder List. Changes posted prior to November 30 preceding the Rate Year, or the next business day if November 30 is not a business day (or such later date as can be accommodated under PJM's billing practices), shall be reflected in the Annual Projection for the Rate Year; changes posted after that date will be reflected, as appropriate, in the True-Up Adjustment for the Rate Year.
- f. The Annual Projection, including the True-Up Adjustment, for each Rate Year shall be subject to review, challenge, true-up, and refunds or surcharges with interest, to the extent and in the manner provided in these Protocols.

Section 2. <u>True-Up Adjustment</u>

AEP will calculate the amount of under- or over-collection of its actual Net Revenue Requirement during the preceding Rate Year ("True-Up Adjustment") after the FERC Form No. 1 data for that Rate Year has been filed with the Commission. The True-Up Adjustment shall be the sum of the True-Up Adjustment Over/Under Recovery as determined in Section 2(a) and the Interest on the True-Up Adjustment Over/Under Recovery as determined in Section 2(b):

a. AEP's projected Net Revenue Requirement collected during the previous Rate Year³ will be compared to AEP's actual Net Revenue Requirement for the previous Rate Year calculated in accordance with AEP's Formula Rate and based upon (i) AEP's FERC Form No. 1 for that same Rate Year, (ii) any FERC orders specifically applicable to AEP's calculation of its annual revenue requirement, (iii) the books and records of AEP (which shall be maintained consistent with the FERC Uniform System of Accounts ("USofA")), (iv) FERC accounting policies and practices applicable to the calculation of annual revenue requirements under formula rates, and (v) any aspects of the PJM Tariff Governing Documents that apply to the calculation of annual revenue requirements under

.

If the initial use of this Formula Rate covers only part of a calendar year, the initial projected annual Net Revenue Requirement will be divided by 12 to calculate the monthly projected cost of service to be collected each month it is effective that first year. Similarly, the actual Net Revenue Requirement will be divided by 12 to calculate the actual monthly cost of service to be collected during those same months of that year. Similar calculations of projected Net Revenue Requirement and actual Net Revenue Requirement will be made for the months prior to the effective date of this Formula Rate using the previous formula rate in effect during those months. The actual Net Revenue Requirements computed under each of the two formula rate periods that initial Rate Year will be added together to obtain the total actual Net Revenue Requirement. The first True-up Adjustment will compare this total actual Net Revenue Requirement to the Net Revenue Requirement collected under the two formulas for that initial Rate Year.

- individual transmission owner formula rates,⁴ to determine any over- or under-recovery ("True-Up Adjustment Over/Under Recovery").
- b. Interest on any True-Up Adjustment Over/Under Recovery shall be calculated for the thirty-six (36) months during which the over or under recovery in the revenue requirement remains outstanding (*i.e.*, from January 1 of the Rate Year being trued-up through December 31 of the year in which the True-Up Adjustment Over/Under recovery is credited or collected). The interest rate to be applied to the True-Up Adjustment Over/Under Recovery amounts will be determined using the average monthly FERC Interest Rate (as determined pursuant to 18 C.F.R. § 35.19a) for the twenty (20) months from the beginning of the Rate Year being trued-up through August 31 of the following year.

Section 3. Annual Update

- a. On or before May 25 following each Rate Year, AEP shall calculate its actual Net Revenue Requirement and the True-Up Adjustment as described in Section 2 ("Annual Update") for such Rate Year and, together with such other information described in this Section 3, shall cause such Annual Update to be posted, in both a PDF and fully-functioning Excel format, at a publicly accessible location on PJM's internet website and OASIS. Within five (5) calendar days of such posting, PJM shall provide notice of such posting via the PJM Exploder List.
- b. If the date for making the Annual Update posting should fall on a weekend or a holiday recognized by the FERC, then the posting shall be due on the next business day.

⁴ PJM Tariff Governing Documents include the PJM Tariff, Bylaws, Criteria, and Membership Agreements.

- c. The date on which the posting occurs shall be that year's "Annual Update Publication

 Date."
- d. Together with the posting of the Annual Update, AEP shall cause to be posted on the PJM website and OASIS the time, date, location, and remote-access information for a stakeholder meeting with Interested Parties in order for AEP to explain its Annual Update and to provide Interested Parties an opportunity to seek information and clarifications regarding the Annual Update ("Annual Update Meeting"). Notice of the Annual Update Meeting shall be provided via the PJM Exploder List no less than seven (7) calendar days prior to the meeting. The Annual Update Meeting shall be held no less than twenty (20) business days and no more than thirty (30) business days after the Annual Update Publication Date. AEP will provide remote access to the Annual Update Meeting in order to ease burdens (e.g. travel costs) to ensure all Interested Parties have the opportunity to participate.
- e. The Annual Update posting for the Rate Year:
 - (i) Shall provide, via the Formula Rate worksheets, sufficiently detailed supporting documentation for data (and all adjustments thereto or allocations thereof) used in the Formula Rate that are not stated in the FERC Form No. 1;⁵

⁵ It is the intent of the Formula Rate, including the supporting explanations and allocations described therein, that each input to the Formula Rate for purposes of determining the actual Net Revenue Requirement for a given Rate Year will be either taken directly from the FERC Form No. 1 or reconcilable to the FERC Form No. 1 by the application of clearly identified and supported information. If the referenced form is superseded, the successor form(s) shall be utilized and supplemented as necessary to provide equivalent information as that provided in the superseded form. If the referenced form is discontinued, equivalent information as that provided in the discontinued form shall be utilized.

- (ii) Shall provide sufficient detail and sufficient explanation to enable Interested

 Parties to replicate the calculation of the Annual Update results from the FERC

 Form No. 1 and verify that each input to the Template is consistent with the requirements of the Formula Rate;
- (iii) Shall identify:
 - A. Any change in accounting that affects inputs to the Template or the resulting charges billed under the Formula Rate ("Accounting Change"), including:
 - i. The initial implementation of an accounting standard or policy;
 - The initial implementation of accounting practices for unusual or unconventional items where FERC has not provided specific accounting direction;
 - iii. Correction of errors and prior period adjustments that impact theTrue-Up Adjustment calculation;
 - iv. The implementation of new estimation methods or policies that change prior estimates; and
 - v. Changes to income tax elections;
 - B. Any items included in the Annual Update at an amount other than on a historic cost basis (e.g., fair value adjustments);
 - C. Any reorganization or merger transaction during the previous year and an explanation of the effect of the accounting for such transaction(s) on inputs to the Annual Update;

- D. For each item identified pursuant to Sections 3.e.iii.A C of these
 Protocols, the individual impact (in narrative format) of such changes on the Annual Update.
- (iv) Shall be subject to review and challenge in accordance with the procedures set forth in Sections 4, 5, and 6 of these Protocols.
- (v) Shall be subject to review and challenge in accordance with the procedures set forth in these Protocols with respect to the prudence of any costs and expenditures included for recovery in the Annual Update; provided, however, that nothing in these Protocols is intended to modify the Commission's applicable precedent with respect to the burden of going forward or burden of proof under formula rates in such prudence challenges; and
- (vi) Shall not seek to modify the Formula Rate and shall not be subject to challenge by any Interested Party seeking to modify the Formula Rate (i.e., any modifications to the Formula Rate will require, as applicable, an FPA section 205 or section 206 filing or initiation of a section 206 investigation).
- f. The following Formula Rate inputs shall be stated values to be used in the Formula Rate until changed pursuant to an FPA section 205 or section 206 proceeding: (i) rate of return on common equity ("ROE"); (ii) the depreciation and/or amortization rates as set forth in Attachment 10 to the Formula Rate template, and (iii) Post-Employment benefits other than Pension ("PBOP") charges pursuant to Statement of Financial Accounting Standards No. 106, Employers' Accounting for Postretirement Benefits Other Than Pensions.

g. Example – Timelines for 2018 Annual Projection and 2019 Annual Update:

On or before October 31, 2017, AEP will determine the projected Net Revenue

Requirement for the 2018 Rate Year. AEP will post the Annual Projection for the 2018

Rate Year in accordance with Section 1 above. On or before May 25, 2019, AEP will

post its Annual Update, consisting of the actual Net Revenue Requirement and True-Up

Adjustment for the 2018 Rate Year determined pursuant to Section 2 above. Such True-Up Adjustment will be reflected in the Annual Projection of the Net Revenue

Requirement for the 2020 Rate Year posted on or before October 31, 2019.

Section 4. Annual Review Procedures

Each Annual Update and Annual Projection shall be subject to the following review procedures ("Annual Review Procedures"):

a. Interested Parties shall have up to the later of two-hundred-ten (210) calendar days after the applicable Publication Date, or thirty (30) calendar days after the receipt of all responses to timely submitted information requests (unless such period is extended with the written consent of AEP or by FERC order) ("Review Period"), to review the calculations and to notify AEP in writing of any specific challenges to the Annual Update or Annual Projection ("Preliminary Challenge"), including challenges related to Accounting Changes. An Interested Party submitting a Preliminary Challenge must specify the inputs, supporting explanations, allocations, calculations, or other information to which it objects, and provide an appropriate explanation and documents to support its challenge. AEP shall cause to be posted all Preliminary Challenges at a

- publicly accessible location on PJM's internet website and OASIS, and a link to the website will be e-mailed to the PJM Exploder List.
- b. In the event of a Preliminary Challenge, AEP will appoint a senior representative to work with the Interested Party (or its representatives) toward a resolution of the dispute.
- c. AEP shall respond in writing to a Preliminary Challenge within twenty (20) business days of receipt, and its response shall notify the challenging party of the extent to which AEP agrees or disagrees with the challenge. If AEP disagrees with the Preliminary Challenge, it will provide the Interested Party with an explanation supporting the challenged inputs, explanations, allocations, calculations, or other information. AEP shall promptly cause to be posted its responses to all Preliminary Challenges at a publicly accessible location on PJM's internet website and OASIS, and a link to the website will be e-mailed to the PJM Exploder List. Notwithstanding the foregoing, Preliminary Challenges and responses to Preliminary Challenges that include material deemed by AEP to be confidential information will not be publicly posted but will be made available to requesting parties pursuant to a confidentiality agreement to be executed by AEP and the requesting party.
- d. AEP shall respond to all Preliminary Challenges submitted during the Review Period by no later than thirty (30) calendar days after the end of the Review Period.
- e. Interested Parties shall have up to one-hundred-fifty (150) calendar days after each annual Publication Date (unless such period is extended with the written consent of AEP or by FERC order) to serve reasonable information requests on AEP ("Discovery Period").

- f. Information requests shall be limited to what is necessary to determine: (i) the extent, effect, or impact of an Accounting Change; (ii) whether the Annual Update or Annual Projection fails to include data properly recorded in accordance with the Protocols; (iii) the proper application of the Template and procedures in the Protocols; (iv) the accuracy of data and consistency with the Formula Rate of the charges shown in the Annual Update or Annual Projection; (v) the prudence of the actual costs and expenditures, including procurement methods and cost control methodologies; (vi) the effect of any change to the underlying USofA or FERC Form No. 1; and (vii) any other information that may reasonably have substantive effect on the calculation of the charge pursuant to the Formula Rate. The information requests shall not otherwise be directed to ascertaining whether the Formula Rate is just and reasonable. Information requests shall not solicit information concerning costs or allocations where the costs or allocation methods have been determined to be appropriate by FERC in the context of prior AEP Annual Updates, except that such information requests shall be permitted if they (i) seek to determine if there has been a change in circumstances, (ii) are in connection with corrections pursuant to Section 6 of these Protocols, or (iii) relate to costs or allocations that have not previously been challenged and adjudicated by FERC.
- g. AEP shall make a good faith effort to respond to reasonable information requests pertaining to the Annual Update or Annual Projection within fifteen (15) business days of receipt of such requests. AEP shall respond to all reasonable information requests no later than thirty (30) calendar days after the end of the Discovery Period. AEP will cause to be posted on the PJM website and OASIS all information requests from Interested Parties and AEP's response(s) to such requests, and a link to the website will be e-mailed

to the PJM Exploder List. Notwithstanding the foregoing, information and document requests and responses to information and document requests that include material deemed by AEP to be confidential information will not be publicly posted but will be made available to requesting parties pursuant to a confidentiality agreement to be executed by AEP and the requesting party. Voluminous materials will be made available at a physical AEP site.

- h. AEP shall not claim that responses to information and document requests provided pursuant to these Protocols are subject to any settlement privilege in any subsequent FERC proceeding addressing AEP's Annual Update or Annual Projection.
- i. To the extent AEP and any Interested Party(ies) are unable to resolve disputes related to information requests submitted in accordance with these Annual Review Procedures, AEP or the Interested Party may petition the FERC to appoint an Administrative Law Judge as a discovery master to resolve the discovery dispute(s) in accordance with these Protocols and consistent with the FERC's discovery rules.
- j. Preliminary Challenges or Formal Challenges (as described in Sections 4 and 5) related to Accounting Changes shall be treated in the same manner under these Protocols as other challenges to the Annual Update or Annual Projection. Failure to make a Preliminary Challenge with respect to an Accounting Change in an Annual Update or Annual Projection shall not act as a bar with respect to a Formal Challenge with respect to that Annual Update or Annual Projection provided that the Interested Party submitted a Preliminary Challenge with respect to one or more other issues. Nor shall such failure bar a subsequent Preliminary Challenge related to a subsequent Annual Update or

- Annual Projection to the extent such Accounting Change affects the subsequent Annual Update or Annual Projection.
- k. If a change made by AEP to its accounting policies, practices, or procedures, or the application of the Formula Rate, is found by the FERC to be unjust, unreasonable, or unduly discriminatory or preferential, then the calculation of the charges to be assessed during the Rate Year then under review, and the charges to be assessed during any subsequent Rate Years, including any True-up Adjustments, shall not include such change, but shall include any remedy that may be prescribed by FERC in the exercise of its discretion as of the effective date of such remedy, to ensure that the Formula Rate continues to operate in a manner that is just, reasonable, and not unduly discriminatory or preferential.

Section 5. Resolution of Challenges

- a. Interested Parties shall have up to two-hundred-seventy (270) days following the applicable Publication Date (unless such period is extended with the written consent of AEP or by FERC order), to file a challenge with the FERC ("Formal Challenge"). Such Formal Challenge shall be submitted in the same docket as the AEP informational filing and shall be served on AEP by electronic service on the date of such filing in accordance with Section 385.2010(f)(3) of the Commission's regulations. Subject to any applicable confidentiality and Critical Energy Infrastructure Information restrictions, all information and correspondence produced by AEP pursuant to these Protocols may be included in any Formal Challenge or other FERC proceeding relating to the Formula Rate.
- b. Formal Challenges are to be filed pursuant to these Protocols, rather than under rule 206, and shall:
 - (i) Clearly identify the action or inaction which is alleged to violate the Formula Rate Template or Protocols;
 - (ii) Explain how the action or inaction violates the filed rate Template or Protocols;
 - (iii) Set forth the business, commercial, economic or other issues presented by the action or inaction as such relate to or affect the party filing the Formal Challenge, including
 - A. The extent or effect of an Accounting Change;
 - B. Whether the Annual Update or Annual Projection fails to include data properly recorded in accordance with these Protocols;

- C. The proper application of the Template and procedures in these Protocols;
- D. The accuracy of the data and consistency with the Formula Rate of the charges shown in the Annual Update or Annual Projection;
- E. The prudence of actual costs and expenditures;
- F. The effect of any change to the underlying Uniform System of Accounts or the FERC Form No. 1; or
- G. Any other information that may reasonably have substantive effect on the calculation of the charge pursuant to the Template.
- (iv) Make a good faith effort to quantify the financial impact or burden (if any) created for the party filing the Formal Challenge as a result of the action or inaction;
- (v) State whether the issues presented are pending in an existing Commission proceeding or a proceeding in any other forum in which the filing party is a party, and if so, provide an explanation why timely resolution cannot be achieved in that forum;
- (vi) State the specific relief or remedy requested, including any request for stay or extension of time, and the basis for that relief;
- (vii) Include all documents that support the facts in the Formal Challenge in possession of, or otherwise attainable by, the filing party, including, but not limited to, contracts and affidavits; and

- (viii) State whether the filing party utilized the Preliminary Challenge procedures described in these Protocols to dispute the action or inaction raised by the Formal Challenge, and, if not, describe why not.
- c. Preliminary and Formal Challenges shall be limited to issues that may be necessary to determine: (i) the extent or effect of an Accounting Change; (ii) whether the Annual Update or Annual Projection fails to include data properly recorded in accordance with these Protocols; (iii) the proper application of the Formula Rate and procedures in these Protocols; (iv) the accuracy of data and consistency with the Formula Rate of the calculations shown in the Annual Update and Annual Projection; (v) the prudence of actual costs and expenditures; (vi) the effect of any change to the underlying Uniform System of Accounts or FERC Form No. 1; or (vii) any other information that may reasonably have substantive effect on the calculation of the charge pursuant to the formula.
- d. Failure to raise an issue in a Preliminary Challenge shall not bar an Interested Party from raising that issue in a Formal Challenge, provided the Interested Party submitted a Preliminary Challenge during the Review Period with respect to one or more other issues. Failure to pursue an issue through a Preliminary Challenge or to lodge a Formal Challenge regarding any issue as to a given Annual Update shall bar pursuit of such issue with respect to that Annual Update, but shall not bar pursuit of such issue or the lodging of a Formal Challenge as to such issue as it relates to a subsequent Annual Update.

- e. Any response by AEP to a Formal Challenge must be submitted to the FERC within thirty (30) calendar days of the date of the filing of the Formal Challenge, and shall be served on the filing party(ies) and the PJM Exploder List on the date of such filing.
- f. In any Formal Challenge proceeding concerning an Annual Update (including corrections), Annual Projection, or Accounting Change(s), AEP shall demonstrate the justness and reasonableness of the rate resulting from its application of the Formula Rate by demonstrating that it has correctly applied the terms of the Formula Rate consistent with these Protocols and that it followed the applicable requirements and procedures in applying the Formula Rate. Nothing herein is intended to alter the burdens applied by FERC with respect to prudence challenges.
- g. Except as specifically provided herein, nothing herein shall be deemed to limit in any way the right of AEP to file unilaterally, pursuant to section 205 of the FPA and the regulations thereunder, an application seeking changes to the Formula Rate or to any of the stated value inputs requiring a section 205 filing under these Protocols (including, but not limited to, ROE and depreciation and amortization rates), or the right of any other party or the Commission to seek such changes pursuant to section 206 of the FPA and the regulations thereunder.
- h. AEP may, at its discretion and at a time of its choosing, make a limited filing pursuant to section 205 to modify stated values in the Formula Rate (i) for amortization and depreciation rates, (ii) to correct obvious errors or omissions in the Formula Rate such as would result from changes to the FERC Form No. 1, or (iii) PBOP charges pursuant to Statement of Financial Accounting Standards No. 106, Employers' Accounting for Postretirement Benefits Other Than Pensions. The sole issue in any such limited

section 205 proceeding shall be whether such proposed change(s) is just and reasonable, and it shall not address other aspects of the Formula Rate or impose upon AEP any burden with respect to such other aspects of the Formula Rate.

Section 6. <u>Changes to Annual Updates</u>

If AEP determines or concedes that corrections to the Annual Update are required, whether under Sections 4 or 5 of these Protocols, including but not limited to those requiring corrections to its FERC Form No. 1, or input data used for a Rate Year that would have affected the Annual Update for that Rate Year, such corrections shall be reflected as adjustments in the Annual Update for the next Rate Year, with interest calculated in accordance with the FERC Interest Rate (as determined pursuant to 18 C.F.R. § 35.19a). This reconciliation mechanism shall apply in lieu of mid-Rate Year adjustments.

Cost of Service Formula Rate Using Actual/Projected FF1 Balances Worksheet G Supporting - Development of Composite State Income Tax Rate COMPANY NAME HERE

State #1 Tax Rate Apportionment Factor - Note 1 Effective State Tax Rate	0.00%
State #2 Tax Rate	
Apportionment Factor - Note 1	
Effective State Tax Rate	0.00%
State #3 Tax Rate	
Apportionment Factor - Note 1	
Effective State Tax Rate	0.00%
State #4 Tax Rate	
Apportionment Factor - Note 1	
Effective State Tax Rate	0.00%
Total Effective State Income Tax Rate	0.00%

Apportionment Factors are determined as part of the Company's annual tax return for that jurisdiction.

Line No.	(A) Account	(B) Total	(C)	(D) Labor	(E) Other	(F) Non-Allocable
NO.	Account	Company NOTE 1	Property	Labor	Other	Non-Anocable
1	Revenue Taxes					
2	List Individual Taxes Here	-				-
3	Real Estate and Personal Property Taxes					
4 5	Real and Personal Property - Jurisdiction #1 Real and Personal Property - Jurisdiction #2	-	-			
6	Real and Personal Property - Jurisdiction #2 Real and Personal Property - Jurisdiction #3	-	-			
7	Real and Personal Property - Other Jurisdictions	-	-			
8	Payroll Taxes					
9	Federal Insurance Contribution (FICA)	-		-		
10 11	Federal Unemployment Tax State Unemployment Insurance	-		-		
12	Production Taxes					
13	List Individual Taxes Here	-				-
14		-				-
15	Miscellaneous Taxes					
16 17	List Individual Taxes Here	-				-
18		- -			- -	
19		-			-	
20		-			-	
21		-				-
22 23		-				-
24	Total Taxes by Allocable Basis					
21	(Total Company Amount Ties to FFI p.114, Ln 14,(c))					
	NOTE 1: The detail of each total company number and its source Functional Property Tax Allocation	in the FERC Form	1 is shown on W	S H-1.		
•		Production	Transmsission	Distribution	General	<u>Total</u>
25	Functionalized Net Plant (TCOS, Lns 41 thru 46) STATE JURISDICTION #1	-	-	-	-	-
26	Percentage of Plant in STATE JURISDICTION #1 Net Plant in STATE JURISDICTION #1 (Ln 25 * Ln 26)					
27 28	Less: Net Value of Exempted Generation Plant	_	-	-	-	-
29	Taxable Property Basis (Ln 27 - Ln 28)	-	-	-	-	-
30	Relative Valuation Factor					<u> </u>
31	Weighted Net Plant (Ln 29 * Ln 30)	-	-	-	-	
32 33	General Plant Allocator (Ln 31 / (Total - General Plant)) Functionalized General Plant (Ln 32 * General Plant)	0.00%	0.00%	0.00%	-100.00%	
33	Functionalized General Plant (Ln 32 "General Plant)	=	-	-	=	-
34 35	Weighted STATE JURISDICTION #1 Plant (Ln 31 + 33) Functional Percentage (Ln 34/Total Ln 34) STATE JURISDICTION #2	0.00%	0.00%	0.00%	-	-
36						
	Percentage of Plant in STATE JURISDICTION #2					
37	Percentage of Plant in STATE JURISDICTION #2 Net Plant in STATE JURISDICTION #2 (Ln 25 * Ln 36)	-	-	-	-	-
37 38	Percentage of Plant in STATE JURISDICTION #2 Net Plant in STATE JURISDICTION #2 (Ln 25 * Ln 36) Less: Net Value of Exempted Generation Plant	-	-		-	-
37 38 39	Percentage of Plant in STATE JURISDICTION #2 Net Plant in STATE JURISDICTION #2 (Ln 25 * Ln 36) Less: Net Value of Exempted Generation Plant Taxable Property Basis (Ln 37 - Ln 38)	-	-		-	 - -
37 38 39 40	Percentage of Plant in STATE JURISDICTION #2 Net Plant in STATE JURISDICTION #2 (Ln 25 * Ln 36) Less: Net Value of Exempted Generation Plant Taxable Property Basis (Ln 37 - Ln 38) Relative Valuation Factor	-	-		-	- -
37 38 39 40 41 42	Percentage of Plant in STATE JURISDICTION #2 Net Plant in STATE JURISDICTION #2 (Ln 25 * Ln 36) Less: Net Value of Exempted Generation Plant Taxable Property Basis (Ln 37 - Ln 38) Relative Valuation Factor Weighted Net Plant (Ln 39 * Ln 40) General Plant Allocator (Ln 41 / (Total - General Plant))	- 0.00%	- - 0.00%	- - 0.00%	- - -100.00%	- -
37 38 39 40 41 42 43	Percentage of Plant in STATE JURISDICTION #2 Net Plant in STATE JURISDICTION #2 (Ln 25 * Ln 36) Less: Net Value of Exempted Generation Plant Taxable Property Basis (Ln 37 - Ln 38) Relative Valuation Factor Weighted Net Plant (Ln 39 * Ln 40) General Plant Allocator (Ln 41 / (Total - General Plant)) Functionalized General Plant (Ln 42 * General Plant)	- - 0.00%	-	-	- - -100.00%	 - - -
37 38 39 40 41 42 43 44	Percentage of Plant in STATE JURISDICTION #2 Net Plant in STATE JURISDICTION #2 (Ln 25 * Ln 36) Less: Net Value of Exempted Generation Plant Taxable Property Basis (Ln 37 - Ln 38) Relative Valuation Factor Weighted Net Plant (Ln 39 * Ln 40) General Plant Allocator (Ln 41 / (Total - General Plant)) Functionalized General Plant (Ln 42 * General Plant) Weighted STATE JURISDICTION #2 Plant (Ln 41 + 43)	-	- 0.00% - -	- 0.00% -	- - -100.00% -	 - - - -
37 38 39 40 41 42 43 44 45	Percentage of Plant in STATE JURISDICTION #2 Net Plant in STATE JURISDICTION #2 (Ln 25 * Ln 36) Less: Net Value of Exempted Generation Plant Taxable Property Basis (Ln 37 - Ln 38) Relative Valuation Factor Weighted Net Plant (Ln 39 * Ln 40) General Plant Allocator (Ln 41 / (Total - General Plant)) Functionalized General Plant (Ln 42 * General Plant) Weighted STATE JURISDICTION #2 Plant (Ln 41 + 43) Functional Percentage (Ln 44/Total Ln 44) STATE JURISDICTION #3	- - 0.00% - - 0.00%	-	-	- - -100.00% - -	- - -
37 38 39 40 41 42 43 44 45	Percentage of Plant in STATE JURISDICTION #2 Net Plant in STATE JURISDICTION #2 (Ln 25 * Ln 36) Less: Net Value of Exempted Generation Plant Taxable Property Basis (Ln 37 - Ln 38) Relative Valuation Factor Weighted Net Plant (Ln 39 * Ln 40) General Plant Allocator (Ln 41 / (Total - General Plant)) Functionalized General Plant (Ln 42 * General Plant) Weighted STATE JURISDICTION #2 Plant (Ln 41 + 43) Functional Percentage (Ln 44/Total Ln 44) STATE JURISDICTION #3 Net Plant in STATE JURISDICTION #3 (Ln 25 - Ln 27 - Ln 37)	-	- 0.00% - -	- 0.00% -	- - -100.00% - -	- - -
37 38 39 40 41 42 43 44 45	Percentage of Plant in STATE JURISDICTION #2 Net Plant in STATE JURISDICTION #2 (Ln 25 * Ln 36) Less: Net Value of Exempted Generation Plant Taxable Property Basis (Ln 37 - Ln 38) Relative Valuation Factor Weighted Net Plant (Ln 39 * Ln 40) General Plant Allocator (Ln 41 / (Total - General Plant)) Functionalized General Plant (Ln 42 * General Plant) Weighted STATE JURISDICTION #2 Plant (Ln 41 + 43) Functional Percentage (Ln 44/Total Ln 44) STATE JURISDICTION #3 Net Plant in STATE JURISDICTION #3 (Ln 25 - Ln 27 - Ln 37) Less: Net Value Exempted Generation Plant	-	- 0.00% - -	- 0.00%	- - -100.00% - -	- - - -
37 38 39 40 41 42 43 44 45	Percentage of Plant in STATE JURISDICTION #2 Net Plant in STATE JURISDICTION #2 (Ln 25 * Ln 36) Less: Net Value of Exempted Generation Plant Taxable Property Basis (Ln 37 - Ln 38) Relative Valuation Factor Weighted Net Plant (Ln 39 * Ln 40) General Plant Allocator (Ln 41 / (Total - General Plant)) Functionalized General Plant (Ln 42 * General Plant) Weighted STATE JURISDICTION #2 Plant (Ln 41 + 43) Functional Percentage (Ln 44/Total Ln 44) STATE JURISDICTION #3 Net Plant in STATE JURISDICTION #3 (Ln 25 - Ln 27 - Ln 37)	-	- 0.00% - -	- 0.00%	- - -100.00% - -	- - -
37 38 39 40 41 42 43 44 45 46 47 48 49 50	Percentage of Plant in STATE JURISDICTION #2 Net Plant in STATE JURISDICTION #2 (Ln 25 * Ln 36) Less: Net Value of Exempted Generation Plant Taxable Property Basis (Ln 37 - Ln 38) Relative Valuation Factor Weighted Net Plant (Ln 39 * Ln 40) General Plant Allocator (Ln 41 / (Total - General Plant)) Functionalized General Plant (Ln 42 * General Plant) Weighted STATE JURISDICTION #2 Plant (Ln 41 + 43) Functional Percentage (Ln 44/Total Ln 44) STATE JURISDICTION #3 Net Plant in STATE JURISDICTION #3 (Ln 25 - Ln 27 - Ln 37) Less: Net Value Exempted Generation Plant Taxable Property Basis Relative Valuation Factor Weighted Net Plant (Ln 48 * Ln 49)	- 0.00%	- 0.00% - 0.00% - 0.00%	- 0.00% - 0.00% 	- -	- - -
37 38 39 40 41 42 43 44 45 46 47 48 49 50 51	Percentage of Plant in STATE JURISDICTION #2 Net Plant in STATE JURISDICTION #2 (Ln 25 * Ln 36) Less: Net Value of Exempted Generation Plant Taxable Property Basis (Ln 37 - Ln 38) Relative Valuation Factor Weighted Net Plant (Ln 39 * Ln 40) General Plant Allocator (Ln 41 / (Total - General Plant)) Functionalized General Plant (Ln 42 * General Plant) Weighted STATE JURISDICTION #2 Plant (Ln 41 + 43) Functional Percentage (Ln 44/Total Ln 44) STATE JURISDICTION #3 Net Plant in STATE JURISDICTION #3 (Ln 25 - Ln 27 - Ln 37) Less: Net Value Exempted Generation Plant Taxable Property Basis Relative Valuation Factor Weighted Net Plant (Ln 48 * Ln 49) General Plant Allocator (Ln 50 / (Total - General Plant)	-	- 0.00% - -	- 0.00%	- - -100.00% - - - - -100.00%	- - -
37 38 39 40 41 42 43 44 45 46 47 48 49 50	Percentage of Plant in STATE JURISDICTION #2 Net Plant in STATE JURISDICTION #2 (Ln 25 * Ln 36) Less: Net Value of Exempted Generation Plant Taxable Property Basis (Ln 37 - Ln 38) Relative Valuation Factor Weighted Net Plant (Ln 39 * Ln 40) General Plant Allocator (Ln 41 / (Total - General Plant)) Functionalized General Plant (Ln 42 * General Plant) Weighted STATE JURISDICTION #2 Plant (Ln 41 + 43) Functional Percentage (Ln 44/Total Ln 44) STATE JURISDICTION #3 Net Plant in STATE JURISDICTION #3 (Ln 25 - Ln 27 - Ln 37) Less: Net Value Exempted Generation Plant Taxable Property Basis Relative Valuation Factor Weighted Net Plant (Ln 48 * Ln 49)	- 0.00%	- 0.00% - 0.00% - 0.00%	- 0.00% - 0.00% 	-	- - -

Cost of Service Formula Rate Using 2008 FF1 Balances

Worksheet H-1 Form 1 Source Reference of Company Amounts on WS H

	(A)		(B)	(C)	(D)		
Li ne No	Annual Tax Expenses by Type (Note 1)		Total Company	FERC FORM 1 Tie-Back	FERC FORM 1 Reference		
1	Revenue Taxes		, in the second				
2	Revenue Tax 1	-					
	<u>(A)</u>	(B)	(C)	(D)	(E)	(F)	(G)
	Real Estate and Personal Propety Tax Detail Annual Tax Expenses by Type (Note 1)	Tax Year	Total Company	FERC FORM 1 Tie-Back	FERC FORM 1 Reference	Tax Year Factor (Note 2)	Transmis sion Function (Note 2)
3	Real Estate and Personal Property Taxes Total (Ln 4 + Ln 5 + Ln 6 + Ln 7)			_			-
4	Real and Personal Property - Jurisdiction 1						-
5	Real and Personal Property – Jurisdiction 2						
6	Real and Personal Property – Jurisdiction 3						
7	Real and Personal Property - Other Jurisdictions		r i				-
Li ne	<u>(A)</u>		(B)	(C)	(D)		
No	Annual Tax Expense by Type (Note 1)		Total Company	FERC FORM 1 Tie-Back	FERC Form 1 Reference		
8	Payroll Taxes						
9	Federal Insurance Contribution (FICA)		-				
10	Federal Unemployment Tax		-				
11	State Unemployment Insurance		-	-			
12	Production Taxes						
13	Production Tax 1		-				
15	Miscellaneous Taxes						
16	Miscellaneous Tax 1		-				
17	Miscellaneous Tax 2		-				
18	Miscellaneous Tax 3		-				
19	Miscellaneous Tax 4		-				
20	Miscellaneous Tax 5		-				
21	Miscellaneous Tax 6		-				

22 Miscellaneous Tax 7
23 Total Taxes by Allocable Basis - -

(Total Company Amount Ties to FFI p.114, Ln 14,(c))

Note 1: The taxes assessed on each operating company can differ from year to year and between operating companies by both the type of taxes and the states in which they were assessed. Therefore, for each company, the types and jurisdictions of tax expense recorded on this page could differ from the same page in the same company's prior year template or from this page in other operating companies' current year templates. For each update, this sheet will be revised to ensure that the total activity recorded hereon equals the total reported in account 408.1 on P. 114, Ln 14 of the FERC Form 1.

Note 2: The transmission functional amounts for any Real Estate and Property taxes listed on pages 263 of the FERC Form 1 will be allocated using the transmission functional allocator calculated for each state in Worksheet H of the applicable year that the taxes were assesed. Real and Personal Property - Other Jurisdictions will be allocated using the Gross Plant Allocator from the applicable year.

Cost of Service Formula Rate Using Actual/Projected FF1 Balances

Worksheet I RESERVED FOR FUTURE USE

Cost of Service Formula Rate Using Actual/Projected FF1 Balances

Worksheet J Supporting Calculation of PROJECTED PJM RTEP Project Revenue Requirement Billed to Benefiting Zones COMPANY NAME HERE

I. Calculate Return and Income Taxes with basis point ROE increase for Projects Qualified for Regional Billing.

Α.	Determine 'R'	with hypothetical	basis point increase	in ROE for Identified Projects
----	----------------------	-------------------	----------------------	--------------------------------

ROE w/o incentives (TCOS, ln 156)	0.00%
Project ROE Incentive Adder	
ROE with additional basis point incentive	0.00%

Determine R (cost of long term debt, cost of preferred stock and equity percentage is from the TCOS, lns 154 through 156)

	<u>%</u>	<u>Cost</u>	Weighted cost
Long Term Debt	0.00%	0.00%	0.000%
Preferred Stock	0.00%	0.00%	0.000%
Common Stock	0.00%	0.00%	0.000%
		R	= 0.000%

В.	Determine Return using	'R' with	hypothetical	basis point	t ROE increase	for Identified Projects.

Rate Base (TCOS, In 68)	-
R (from A. above)	0.000%
Return (Rate Base x R)	-

C. Determine Income Taxes using Return with hypothetical basis point ROE increase for Identified Projects.

C. Determine theome taxes using Return with hypothetical basis point ROE merease for fuentified riojects.		
Return (from B. above)		-
Effective Tax Rate (TCOS, ln 114)		0.00%
Income Tax Calculation (Return x CIT)	-	
ITC Adjustment	-	
Excess Deferred Income Tax	-	
Tax Affect of Permanent Differences	-	
Income Taxes	-	

II. Calculate Net Plant Carrying Charge Rate (Fixed Charge Rate or FCR) with hypothetical basis point ROE increase.

A. Determine Annual Revenue Requirement less return and Income Taxes.

Annual Revenue Requirement (TCOS, ln 1)

Lease Payments (TCOS, 95) Return (TCOS, ln 126)

Income Taxes (TCOS, ln 125)	=
Annual Revenue Requirement, Less Lease Payments, Return and Taxes	
B. Determine Annual Revenue Requirement with hypothetical basis point increase in ROE.	
Annual Revenue Requirement, Less Lease payments, Return and Taxes	-
Return (from I.B. above)	-
Income Taxes (from I.C. above)	=
Annual Revenue Requirement, with Basis Point ROE increase	-
Depreciation (TCOS, ln 100)	=
Annual Rev. Req, w/ Basis Point ROE increase, less Depreciation	-
C. Determine ECD with howethetical basis maint DOE increases	

C. Determine FCR with hypothetical basis point ROE increase.

Incremental FCR with Basis Point ROE increase, less Depreciation

Net Transmission Plant (TCOS, ln 42)	-
Annual Revenue Requirement, with Basis Point ROE increase	-
FCR with Basis Point increase in ROE	
Annual Rev. Req, w / Basis Point ROE increase, less Dep.	-
FCR with Basis Point ROE increase, less Depreciation	
FCR less Depreciation (TCOS, ln 10)	

III Calculation of Composite Depreciation Rate

SUMMARY OF PROJECTED ANNUAL RTEP REVENUE REQUIREMENTS				
		Rev Require	W Incentives	Incentive Amounts
	PROJECTED YEAR	Projected	Year -	- \$ -

0.00%

0.00%

0.00%

0.00%

Page 25

Average Transmission Plant Balance for Rate Year (TCOS, ln 21)

Annual Depreciation and Amortization Expense (TCOS, ln 100)

Composite Depreciation Rate

Depreciable Life for Composite Depreciation Rate

Round to nearest whole year

- 4

Worksheet J - ATRR PROJECTED Calculation for PJM Projects Charged to Benefiting Zones

IV. Determine the Revenue Requirement, and Additional Revenue Requirement for facilities receiving incentives.

_	A. Base Plan Facilities Facilities receiving incentives accepted by FERC in Docket No. Project Description:				(e.g. ER05-925-000)		Current Projected Year ARR - Current Projected Year ARR w/ Incentive - Current Projected Year Incentive ARR -]	
Details							Current i rojec	tieu Teal Thee	nuve AKK		1
Investment Current Year Service Year (yyyy) Service Month (1-12) ROE increase accepted by FERC (Basis Points) FCR w/o incentives, less depreciation						Projected Year	CUMULATIVE REVENUE REQ	UMULATIVE HISTORY OF PROJECTED ANNUAL REVENUE REQUIREMENTS: LATIVE HISTORY OF PROJECTED ANNUAL IUE REQUIREMENTS:			
Useful life CIAC (Yes or No)			ved for these facilities, les	ss dep.		0.00% 0.00%	INPUT PROJECTED ARR (WITH & WITHOUT INCENTIVES) FROM EACH PRIOR YEAR TEMPLATE BELOW TO MAINTAI HISTORY OF PROJECTED ARRS OVER THE LIFE OF THE PROJECT.			NTAIN	
Investment Year	Beginning Balance	Depreciation Expense	Ending Balance	RTEP Rev. Req't.	RTEP Rev. Req't. with Incentives **	Incentive Rev. Requirement ##	RTEP Projected Rev. Req't.From Prior Year Template w/o Incentives		RTEP Projected Rev. Req't.From Prior Year Template with Incentives **		
-	-	-	-	-	-	\$ -					

^{**} This is the total amount that needs to be reported to PJM for billing to all regions.

Project Totals

This is the calculation of additional incentive revenue on projects deemed by the FERC to be eligible for an incentive return. This additional incentive requirement is applicable for the life of this specific project. Each year the revenue requirement calculated for PJM should be incremented by the amount of the incentive revenue calculated for that year on this project.

In order to calculate the proper monthly RTEP billing amount, PJM requires a 12 month revenue requirement for each RTEP project. As a result, notwithstanding the fact that the project was in service for a partial year, the project revenue requirement in the year that the project goes into service has been annualized (shown at the full-year level) so that PJM will collect the correct monthly billings.

of Service Formula rate Compression 11 February									
Worksheet K Supporting Calculation of TRUE-UP PJM RTEP Project Revenue Requirement Billed	to Benefiting	g Zones							
COMPANY NAME HERE									
. Calculate Return and Income Taxes with basis point ROE increase for Projects Qualified	for Regiona	l Billing.							
A. Determine 'R' with hypothetical basis point increase in ROE for Identified Projects	Ö	O							
ROE w/o incentives (TCOS, ln 156)		0.00%							
Project ROE Incentive Adder									
ROE with additional basis point incentive		0.00%							
Determine R (cost of long term debt, cost of preferred stock and equity percentage is from the TCOS, lns 154 through 156)									
		<u>%</u>	<u>Cost</u>	<u>Weig</u>	ghted cost				
Long Te	erm Debt	0.00%	0.00%		0.000%				
Preferr	ed Stock	0.00%	0.00%		0.000%				
Comm	on Stock	0.00%	0.00%		0.000%				
]	R =	0.000%				
B. Determine Return using 'R' with hypothetical basis point ROE increase for Identified	Projects.								
Rate Base (TCOS, ln 68)	-		-						
R (from A. above)			0.00	0%					

C. Determine Income Taxes using Return with hypothetical basis point ROE increase for Identified Projects.

Return (from B. above) Effective Tax Rate (TCOS, ln 114) 0.00%

Income Tax Calculation (Return x CIT) ITC Adjustment Excess Deferred Income Tax Tax Affect of Permanent Differences Income Taxes

II. Calculate Net Plant Carrying Charge Rate (Fixed Charge Rate or FCR) with hypothetical basis point ROE increase.

A. Determine Annual Revenue Requirement less return and Income Taxes.

Annual Revenue Requirement (TCOS, ln 1) Lease Payments (TCOS, Ln 95) Return (TCOS, ln 126)

Annual Revenue Requirement, Less Lease Payments, Return and Taxes

B. Determine Annual Revenue Requirement with hypothetical basis point increase in ROE.

Annual Revenue Requirement, Less Lease Payments, Return and Taxes

Return (from I.B. above)

Income Taxes (from I.C. above)

Income Taxes (TCOS, ln 125)

Annual Revenue Requirement, with Basis Point ROE increase

Depreciation (TCOS, ln 100)

Return (Rate Base x R)

Annual Rev. Req, w/ Basis Point ROE increase, less Depreciation

C. Determine FCR with hypothetical basis point ROE increase.

Net Transmission Plant (TCOS, ln 42)

Annual Revenue Requirement, with Basis Point ROE increase

FCR with Basis Point increase in ROE

Annual Rev. Req, w / Basis Point ROE increase, less Dep.

FCR with Basis Point ROE increase, less Depreciation

FCR less Depreciation (TCOS, ln 10)

Incremental FCR with Basis Point ROE increase, less Depreciation

III. Calculation of Composite Depreciation Rate

Average Transmission Plant Balance for Rate Year (TCOS, ln 21)

Annual Depreciation and Amortization Expense (TCOS, ln 100)

Composite Depreciation Rate

Depreciable Life for Composite Depreciation Rate

Round to nearest whole year

Page 1 of 2

SUMMARY OF TRUED-UP ANNUAL REVENUE REQUIREMENTS FOR RTEP PROJECTS Rev Require W Incentives Incentive Amounts TRUE-UP YEAR Historic Year As Projected in Prior Year WS J Actual after True-up \$ -True-up of ARR For Historic Year -0.00%0.00% 0.00%

0.00%

0.00%

COMPANY NAME HERE Worksheet K - ATRR TRUE-UP Calculation for PJM Projects Charged to Benefiting Zones

IV. Determine the Revenue Requirement, and Additional Revenue Requirement for facilities receiving incentives.

A. Base Plan Facilities

Facilities receiving incentives accepted by	FERC in Docket No.
racing receiving incentives accepted by	TERC III DUCKET NO.

(e.g. ER05-925-000)

Project Description:

Details								
Investment		Current Year					Historic Year	
Service Year (yyyy)		ROE increase acce	epted by FERC (Bas	is Points)			_	
Service Month (1-12)		FCR w/o incentive depreciation					0.00%	
Useful life	_	FCR w/incentives dep.	w/incentives approved for these facilities, less					
CIAC (Yes or No)	No	Annual Depreciati	ual Depreciation Expense					
Investment Year	Beginning Balance	Depreciation Expense	Ending Balance	Average Balance	RTEP Rev. Req't. w/o Incentives	RTEP Rev. Req't. with Incentives **	Incentive Rev. Requirement ##	
							\$	

Project Totals - - - -

This is the calculation of additional incentive revenue on projects deemed by the FERC to be eligible for an incentive return.

additional incentive requirement is applicable for the life of this specific project. Each year the revenue requirement calculated for PJM

should be incremented by the amount of the incentive revenue calculated for that year on this project.

Page 2 of 2

Historic Year	Rev Require	W Incentives	Incentive Amounts
Prior Yr Projected	-	-	-
Prior Yr Actual	-	-	-
True-Up Adjustment	_	_	_

TRUE UP OF PROJECT REVENUE REQUIREMENT FOR PRIOR YEAR:

CUMULATIVE HISTORY OF TRUED-UP ANNUAL REVENUE REQUIREMENTS:

INPUT TRUE-UP ARR (WITH & WITHOUT INCENTIVES) FROM EACH PRIOR YEAR TEMPLATE BELOW TO MAINTAIN HISTORY OF TRUED-UP ARRS OVER THE LIFE OF THE PROJECT.

RTEP Projected Rev. Req't.From Prior Year WS J w/o Incentives	RTEP Rev Req't True-up w/o Incentives	RTEP Projected Rev. Req't.From Prior Year WS J with Incentives **	RTEP Rev Req't True-up with Incentives **	True-up of Incentive with Incentives **
	\$ - \$		\$ - \$	\$ - \$ -

^{**} This is the total amount that needs to be reported to PJM for billing to all regions.

AEP East Companies Cost of Service Formula Rate Using Actual/Projected FF1 Balances Worksheet L COMPANY NAME HERE

RESERVED FOR FUTURE USE

Cost of Service Formula Rate Using Actual/Projected FF1 Balances Worksheet M Supporting Calculation of Capital Structure and Weighted Average Cost of Capital Company Name

Lin e No	Month	Proprietary Capital	Less: Preferred Stock	Less Undistributed Sub Earnings (Acct 216.1)	Less AOCI (Acct 219.1)	Average Balance of Common Equity (f)=(b)-(c)-(d)-(
	(a)	(b)	(c)	(d)	(e)	e)
	(Note A) December Prior to Rate	(FF1 112.16)	(FF1 250-251)	(FF1 112.12)	(FF1 112.15)	
1	Year					-
2	January					-
3	February					-
4	March					-
5	April					-
6	May					-
7	June					-
8	July					-
9	August					-
10	September					-
11	October					-
12	November					-
13	December of Rate Year					-
14	Average of the 13 Monthly Balances	-	-	-	-	_

		Average Balance of Long Term Debt								
Lin e No	Month	Acct 221 Bonds	Less: Acct 222 Reacquired Bonds	Acct 223 LT Advances from Assoc. Companies	Acct 224 Senior Unsecured Notes	Less: Fair Value Hedges	Gross Proceeds Outstanding Long- Term Debt (g)=(b)-(c)+(d)+(
	(a)	(b)	(c)	(d)	(e)	(f)	e)-(f)			
	(Note A) December Prior to Rate	(FF1 112.18)	(FF1 112.19)	(FF1 112.20)	(FF1 112.21)	FF1, page 257, Col. (h) - Note 1				
15	Year						-			
16	January						-			
17	February						-			
18	March						-			
19	April						-			
20	May						-			
21	June						-			
22	July						-			
23	August						-			
24	September						-			
25	October						-			
26	November						-			
27	December of Rate Year						-			
28	Average of the 13 Monthly Balances	-			<u>-</u>		-			

NOTE 1: The balance of fair value hedges on outstanding long term debt are to be excluded from the balance of long term debt included in the formula's capital structure. (Page 257 Column H of the FF1)

Development of Cost of Long Term Debt Based on Average Outstanding Balance

	(a)	(b)	(c)	(d)	(e)	(f)	(g)
29	Annual Interest Expense for 2017						
	Interest on Long Term Debt - Accts 221						
30	- 224 (256-257.33.i)						
	Less: Total Hedge Gain/Expense Accum	ulated from p					
	256-257, col. (i) of FERC Form 1 include	ded in Ln 30					
31	and shown in 50 below.			-			
	Plus: Allowed Hedge Recovery From						
32	Ln 55 below.			-			
	Amort of Debt Discount & Expense -						
33	Acct 428 (117.63.c)						
	Amort of Loss on Reacquired Debt -						
34	Acct 428.1 (117.64.c)						
	Less: Amort of Premium on Debt - Acct						
35	429 (117.65.c)						
	Less: Amort of Gain on Reacquired Deb	t - Acct 429.1					
36	(117.66.c)						
	Total Interest Expense (Ln 30 - 31 +				-		
37	33 + 34 - 35 - 36)			-			
	Average Cost of Debt for 2017 (Ln 37/	,]		
38	ln 28 (g))			#DIV/0!			

CALCULATION OF RECOVERABLE HEDGE GAINS/LOSSES

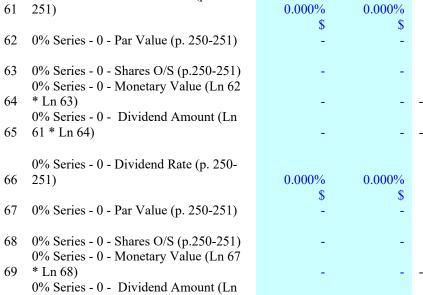
39 NOTE: The net amount of hedging gains or losses recorded in account 427 to be recovered in this formula rate should be limited to the effective portion of pre-issuance cash flow hedges that are amortized over the life of the underlying debt issuances. The recovery of a net loss or passback of a net gain will be limited to five basis points of the total Capital Structure. Amounts related to the ineffective portion of pre-issuance hedges, cash settlements of fair value hedges issued on Long Term Debt, post-issuance cash flow hedges, and cash flow hedges of variable rate debt issuances are not recoverable in this formula and are to be recorded in the "Excludable" column below.

Less Total **Excludable** Net HEDGE AMOUNTS BY ISSUANCE Hedge **Amounts** Includable Remaining (FROM p. 256-257 (i) of the FERC (Gain)/Los (See NOTE Hedge Unamortized **Begin** Form 1) s for 2017 on Line 39) **Balance Ending** Amount ning 40 41 42 43 44 45 46 47 48 49 Total Hedge Amortization Hedge Gain or Loss Prior to Application of Recovery Limit (Sum of Lines 40 to 48) Total Average Capital Structure 52 Balance for 2017 (TCOS, Ln 157) Financial Hedge Recovery Limit - Five Basis Points 53 of Total Capital 0.0005Limit of Recoverable Amount Recoverable Hedge Amortization (Lesser of Ln 51 or Ln 54)

Development of Cost of Preferred Stock

	Preferred Stock			Average
	0% Series - 0 - Dividend Rate (p. 250-			
56	251)	0.000%	0.000%	
		\$	\$	
57	0% Series - 0 - Par Value (p. 250-251)	-	-	
58	0% Series - 0 - Shares O/S (p.250-251)	_	-	
	0% Series - 0 - Monetary Value (Ln 57			
59	* Ln 58)	-	-	-
60	0% Series - 0 - Dividend Amount (Ln			

Amortization Period

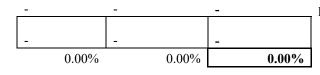


71 Balance of Preferred Stock (Lns 59, 64, 69)

66 * Ln 69)

72 Dividends on Preferred Stock (Lns 60, 65, 70)

73 Average Cost of Preferred Stock (Ln 72/71)



Year End Total Agrees to FF1 p.112, Ln 3, col (c) & (d)

Cost of Service Formula Rate Using Actual/Projected FF1 Balances

Worksheet N - Gains (Losses) on Sales of Plant Held For Future Use

Note: Gain or loss on plant held for future are recorded in accounts 411.6 or 411.7 respectively. Sales will be functionalized based on the description of that asset. Sales of transmission assets will be direct assigned; sales of general assets will be functionalized on labor. Sales of plant held for future use related to generation or distribution will not be included in the formula.

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
Line	Date	Property Description	Function (T) or (G) T = Transmission	Basis	Proceeds	(Gain) / Loss	Functional Allocator	Functionalized Proceeds (Gain) / Loss	FERC Account
			G = General						
1						-	0.000%	-	
2							0.0000/		
2						-	0.000%	-	
3						<u>-</u>	0.000%	-	
J							0.00070		
4				Net (Gain) or Loss fo	or Rate Year	-		_	-

Cost of Service Formula Rate Using Actual/Projected FF1 Balances

Worksheet O - Calculation of Postemployment Benefits Other than Pensions Expenses Allocable to Transmission Service

COMPANY NAME HERE

1 Total AEP East Operating Company PBOP Settlement Amount

Allocation of PBOP Settlement Amount for Rate Year:

Total Company Amount

Line #	Company	Actual Expense (Including AEPSC Billed OPEB)	Ratio of Company Actual to Total	Allocation of PBOB Recovery Allowance	Labor Allocator for Rate Year	Actual Expense	Allowable Expense	One Year Functional Expense (Over)/Under	
		(A) (Line 14)	(B)=(A)/Total (A)	(C)=(B)*1	(D)	(E)=(A)*(D)	(F)=(C)*(D)	(G)=(E)-(F)	
2	APCo		0.00%	-		-	-	-	
3	I&M		0.00%	-		-	-	-	
4	KNGP		0.00%	-		-	-	-	
5	OPCo		0.00%	-		-	-	-	
6	WPCo		0.00% _	-		-	-	<u>-</u>	
7	Sum of Lines 2 to 6	-		-		-	-	-	
	Detail of Actual PBOP Expenses to be	Removed in Cost of Service							AED E 4
9	 8 Direct Charged PBOP Expense per Actuarial Report Additional PBOP Ledger Entries (from 9 Company Records) 10 Medicare Subsidy 		<u>APCo</u>	<u>I&M</u>		<u>KNGSPT</u>	<u>OPCo</u>	<u>WPCo</u>	AEP East Total -
12	1 • 1 \		-	-	-	-	-	-	- -
13	Company PBOP Expense (Ln 11 + Ln 1)	2)	-	-		-	-	-	

Note:

For the rate year 2017 and adjusted every four years thereafter, using the annual actuarial report produced for that year, filed as part of the informational filing, Worksheet O will be used to adjust PBOP costs for the next four years (i.e. 2017, 2018, 2019, 2020). If the annual actuarial report projects PBOP costs during the next four years, taken together with the then current cumulative PBOP cost/allowance position, will, absent a change in the PBOP allowance, cause the AEP Companies to over or under collect their cumulative PBOP costs by more than 20% of the projected next four year's total cost, the PBOP allowance shall be adjusted. Worksheet O will be used in the process of updating the PBOP allowance determining (a) the level of cumulative over or under collections during the period since the PBOP allowance was last set, including carrying costs based on the weighted average cost of capital ("WACC") each year from the formula actual rate; (b) the cumulative net present value of projected PBOP costs during the next four years, as estimated by the then current actuarial report, assuming a discount rate equal to the actual formula rate WACC for the prior calendar year; and (c) the cumulative net present value of continued collections over the next four years based on the then effective PBOP allowance, assuming a discount rate equal to the prior year WACC. If the absolute value of (a)+(b)-(c) exceeds 20% of (b), then the PBOP allowance used in the formula rate calculation shall be changed to the value that will cause the projected result of (a)+(b)+(c) to equal zero. If the projected over or under collection during the next four years will be less than 20% of (b), then the PBOP allowance will continue in effect for the next four years at the then effective rate. If it is determined through this procedure AEP Companies will over-recover actual PBOP expenses by more than 20% over the subsequent four-year period, AEP shall make a filing under FPA Section 205 to change the PBOP expense stated in the formula rat

AEP EAST COMPANIES

Worksheet - P CALCULATION OF

TOTAL WEIGHTED AVERAGE DEPRECIATION RATES

FOR TRANSMISSION PLANT PROPERTY ACCOUNT

EFFECTIVE AS OF 3/6/2019

FOR MULTIPLE JURISDICTION COMPANIES

APPALACHIAN POWER COMPANY

		VIRO	GINIA			WE	ST VIRGINIA			FERC W	HOLESALE	FE	ERC KIN	GSPORT	_	COMPANY
		(1)				(2)				(3)		(4)				
			WTD AVG	. PSC	OF WV		WTD AVG.			WTD AVO	J.	V	VTD AVC	r.	WTD AVG.	
PLANT	VA SCC	ALLOCATION	DEPREC.	APPF	ROVED	ALLOCATION	DEPREC.	FERC	ALLOCATION	DEPREC	. FERC	ALLOC	CATION	DEPREC.	DEPREC.	
ACCT.	RATES	FACTOR (5)	RATE	RA	ATES	FACTOR (5)	RATE	RATES	FACTOR (5)	RATE	RATES	FACTO	OR (5)	RATE	RATE	
TRANSMISSION PLAN																
Land Rights - Va.	350. 1 0.66	% 1.000000 (0.66%												0.66%	
Energy Storage Equipment		351.0				14.22%	1.000000	14.22%							14.22%	
Structures & Improvemen		352.0		0.492648	0. 76%	1.62%	0.414603	0.67%	2.19%	0.033874	0.07%	2.19%	0.0588	74 0.13%	1.63%	
Station Equipment	11.5	353.0		0.492648	0. 76%	2.37%	0.414603	0.98%	2.19%	0.033874	0.07%	2.19%	0.0588		2.14%	
Towers & Fixtures		354.0		0.492648	0.56%	1.59%	0.414603	.0.66%	2.19%	0.033874	0.07%	2.19%	0.0588		1.42%	
Poles & Fixtures				0.492648	1.36%	2.71%	0.414603	1.12%	2.19%	0.033874	0.07%	2.19%	0.0588		2.68%	
Poles & Fixtures		355.0	2.7770	0.49264	1.30%	2./170	0.414003	1.1270	2.1970	0.033874	0.0770	2.1970	0.0388	74 0.13%	2.08%	
Overhead Conductor		356.0	1.01%	8	0.50%	1.53%	0.414603	.0.63%	2.19%	0.033874	0.07%	2.19%	0.0588	74 0.13%	1.33%	
Underground Conduit		357.0	1.23%	0.492648	0.61%	3.71%	0.414603	1.54%	2.19%	0.033874	0.07%	2.19%	0.0588	74 0.13%	2.35%	
Underground Conductors		358.0	3.18%	0.492648	1.57%	5.24%	0.414603	2.17%	2.19%	0.033874	0.07%	2.19%	0.0588	74 0.13%	3.94%	
GENERAL PLANT																
Structures and Improvement	ents	390.0	1.50%	0.519557	0.78%	1.91%	0.425935	0.81%	3.43%	0.019780	0.07%	3.43%	0.03472	28 0.12%	1.78%	
Office Furniture and Equi	p.	391.0	2.78%	0.519557	1.44%	3.17%	0.425935	1.35%	3.43%	0.019780	0.07%	3.43%	0.03472	28 0.12%	2.98%	
Transportation Equipment	t	392.0	0.00%	0.519557	0.00%	3.40%	0.425935	1.45%	3.43%	0.019780	0.07%	3.43%	0.03472		1.64%	
Stores Equipment		393.0	1.60%	0.519557	0.83%	1.80%	0.425935	0.77%	3.43%	0.019780	0.07%	3.43%	0.03472	28 0.12%	1.79%	
Tools, Shop and Garage Equipment		394.0	2.07%	0.519557	1.08%	2.57%	0.425935	1.09%	3.43%	0.019780	0.07%	3.43%	0.03472	28 0.12%	2.36%	
Laboratory Equipment		395.0		0.519557	0.79%	4.01%	0.425935	1.71%	3.43%	0.019780	0.07%	3.43%	0.03472		2.69%	
Power Operated Equipment	nt	396.0		0.519557	0.00%	3.90%	0.425935	1.66%	3.43%	0.019780	0.07%	3.43%	0.03472		1.85%	
Communications Equipme		397.0		0.519557	1.70%	4.98%	0.425935	2.12%	3.43%	0.019780	0.07%	3.43%	0.0347		4.01%	
Micellaneous Equipment		398.0		0.519557	1.30%	2.70%	0.425935	1.15%	3.43%	0.019780	0.07%	3.43%	0.0347		2.64%	
1 1																

Approved by FERC March 2, 1990 in Docket ER90-

(3) 132

⁽¹⁾ As approved in VA Case No. PUE 2011-00037 on Nov. 30, 2011. Depreciation rates were made effective on February 1, 2012.

⁽⁴⁾ Approved by FERC March 2, 1990 in Docket ER90-133

⁽²⁾ Approved by PSC of WV Order dated February 27, 2019 in Case No. 18-0645-E-D effective March 6, 2019.

⁽⁵⁾ The demand allocation factors are updated annually as of January 1, based on the 12 monthly CP's as of the previous September 30th.

(6) Energy Storage Equipment is a new account established per FERC Order 784.

GENERAL NOTES:

The rates for each AEP company have been approved by their respective regulatory commissions.

APCo falls under the authority of Virginia, West Virginia and the FERC. Therefore, APCo's rates are a composite of the jurisdictions under which it operates. Each jurisdictions to derive the composite rate for the company.

AEP will make a 205 filing whenever a company's rates are changed by their commission(s), or if the methodology to calculate the jurisdictional allocator in multiple-state companies changes. Changes in the allocation factors will not necessitate a 205 filing.

AEP EAST COMPANIES Worksheet - P CALCULATION OF TOTAL WEIGHTED AVERAGE DEPRECIATION RATES

FOR TRANSMISSION PLANT PROPERTY ACCOUNT EFFECTIVE AS OF March 11, 2020

FOR MULTIPLE JURISDICTION COMPANIES INDIANA MICHIGAN POWER COMPANY

					INDIANA MICH	IGAN POWER COMP	AINI				
			INDIANA			MICHIGAN			FERC WHOLESAL	E	TOTAL COMPANY
		(1)			(2)			(3)			
				WTD AVG.	MPSC		WTD AVG.			WTD AVG.	WTD AVG.
	PLANT	IURC	ALLOCATION	DEPREC.	APPROVED	ALLOCATION	DEPREC.	FERC	ALLOCATION	DEPREC.	DEPREC.
	ACCT.	RATES	FACTOR (4)	RATE	RATES	FACTOR (4)	RATE	RATES	FACTOR (4)	RATE	RATE
TRANSMISSION PLANT											
Land Improvements Structures &	350.1	1.66%	0.6623353	1.0995%	1.62%	0.3376647	0.5470%	1.62%	0.3376647	0.5470%	1.65%
Improvements	352.0	1.77%	0.6623353	1.1723%	1.74%	0.3376647	0.5875%	1.74%	0.3376647	0.5875%	1.76%
Station Equipment	353.0	2.43%	0.6623353	1.6095%	2.41%	0.3376647	0.8138%	2.41%	0.3376647	0.8138%	2.42%
Towers & Fixtures	354.0	2.57%	0.6623353	1.7022%	2.45%	0.3376647	0.8273%	2,45%	0.3376647	0.8273%	2.53%
Poles & Fixtures	355.0	3.19%	0.6623353	2.1128%	3.17%	0.3376647	1.0704%	3.17%	0.3376647	1.0704%	3.18%
Overhead Conductors	356.0	2.35%	0.6623353	1.5565%	2.28%	0.3376647	0.7699%	2.28%	0.3376647	0.7699%	2.33%
Underground Conduit Underground	357.0	2.30%	0.6623353	1.5234%	2.21%	0.3376647	0.7462%	2.21%	0.3376647	0.7462%	2.27%
Conductors	358.0	1.93%	0.6623353	1.2783%	1.90%	0.3376647	0.6416%	1.90%	0.3376647	0.6416%	1.92%
Trails & Roads	359.0	1.61%	0.6623353	1.0664%	1.59%	0.3376647	0.5369%	1.59%	0.3376647	0.5369%	1.60%
GENERAL PLANT Structures and			0.6818683								
Improvements Office Furniture and	390.0	2.08%	0.6818683	1.4183%	2.08%	0.3181317 0.3181317	0.6617%	2.08%	0.3181317	0.6617%	2.08%
Equip. Transportation	391.0	4.79%	0.6818683	3.2661%	4.84%	0.3181317	1.5398%	4.84%	0.3181317	1.5398%	4.81%
Equipment	392.0	4.64%		3.1639%	4.68%		1.4889%	4.68%	0.3181317	1.4889%	4.65%
Stores Equipment Tools, Shop and	393.0	7.35%	0.6818683 0.6818683	5.0117%	7.38%	0.3181317 0.3181317	2.3478%	7.38%	0.3181317	2.3478%	7.36%
Garage Equipment Laboratory	394.0	6.99%	0.6818683	4.7663%	7.07%	0.3181317	2.2492%	7.07%	0.3181317	2.2492%	7.02%
Equipment Power Operated	395.0	5.41%	0.6818683	3.6889%	5.46%	0.3181317	1.7370%	5.46%	0.3181317	1.7370%	5.43%
Equipment Communications	396.0	4.81%	0.6818683	3.2798%	4.90%	0.3181317	1.5588%	4.90%	0.3181317	1.5588%	4.84%
Equipment Micellaneous	397.0	3.91%	0.6818683	2.6661%	3.93%	0.3181317	1.2503%	3.93%	0.3181317	1.2503%	3.92%
Equipment	398.0	3.32%		2.2638%	3.35%		1.0657%	3.35%	0.3181317	1.0657%	3.33%

⁽¹⁾ As approved in Indiana Cause No. 45235 effective March 11, 2020.

⁽²⁾ As approved in Michigan Case No. U-20359 effective February 1, 2020.

⁽³⁾ FERC wholesale formula rate agreements specify that the depreciation rates in the formula rates change upon approval of MPSC rates in the Michigan jurisdiction.

(4) The rates approved for each jurisdiction are updated when approved by that commission. These demand-based allocation factors for all jurisdictions are updated when new rates are approved in one of the jurisdictions. These allocation factors reflect I&M's 12 monthly Coincident Peaks during test year of the most recent rate case.

GENERAL NOTES:

The rates for each AEP company have been approved by their respective regulatory commissions.

I&M falls under the authority of Indiana, Michigan and the FERC. Therefore, I&M's rates are a composite of the jurisdictions under which it operates. Each jurisdictions' rate is multiplied by an allocation factor, and the product for each jurisdiction is added with the other jurisdictions to derive the composite rate for the company.

AEP will make a 205 filing whenever a company's rates are changed by their commission(s), or if the methodology to calculate the jurisdictional allocator in multiple-state companies changes. Changes in the allocation factors will not necessitate a 205 filing.

AEP EAST COMPANIES PJM FORMULA RATE

WORKSHEET P - TRANSMISSION DEPRECIATION RATES

EFFECTIVE AS OF 9/1/2016

FOR SINGLE JURISDICTION COMPANIES

KINGSPORT POWER COMPANY

	PLANT	
	ACCT.	RATES
		Note 1
TRANSMISSION PLANT		
Structures & Improvements	352.0	1.04%
Station Equipment	353.0	1.49%
Towers & Fixtures	354.0	0.12%
Poles & Fixtures	355.0	2.14%
Overhead Conductors	356.0	0.77%
Underground Conduit	357.0	Note 2
Underground Conductors	358.0	Note 2
Composite Transmission Depreciation Rate		1.46%
GENERAL PLANT		
Structures & Improvements	390.0	1.71%
Office Furniture & Equipment	391.0	2.82%
Stores Equipment	393.0	2.22%
Tools Shop & Garage Equipment	394.0	3.12%
Laboratory Equipment	395.0	3.17%
Communication Equipment	397.0	3.32%
Miscellaneous Equipment	398.0	4.92%

Total General Plant 3.25%

Reference:

Note 1: Rates Approved In Tennessee Regulatory Authority Docket No. 16-00001.

Note 2: Kingsport Power Company does not have investment in plant accounts 357 or 358. Therefore, there are no depreciation rates approved for these plant accounts.

General Note
AEP will make a 205 filing whenever a company's rates are changed by their commission(s), or if the methodology to calculate the jurisdictional allocator in multiple-state companies changes. Changes in the allocation factors will not necessitate a 205 filing.

AEP EAST COMPANIES

PJM FORMULA RATE

WORKSHEET P - TRANSMISSION DEPRECIATION RATES

EFFECTIVE AS OF 1/1/2012

FOR SINGLE JURISDICTION COMPANIES

OHIO POWER COMPANY

	PLANT ACCT.	RATES Note 1
TRANSMISSION PLANT (Note 1)		
Structures & Improvements	352.0	2.02%
Station Equipment	353.0	2.29%
Twrs and Fixtures Above 69 KV	354.0	1.88%
Twrs and Fixtures Below 69 KV	354.0	1.88%
Poles and Fixtures Above 69 KV	355.0	3.52%
Poles and Fixtures Below 69 KV	355.0	3.52%
Overhead Conductor & Devices Above 69KV	356.0	1.91%
Overhead Conductor & Devices MSP	356.0	1.91%
Overhead Conductor & Devices 138KV/Above	356.0	1.91%
Overhead Conductor & Devices 69KV/Below	356.0	1.91%
Overhead Conductor & Devices CLR 69KV/Below	356.0	1.91%
Underground Conduit	357.0	2.26%
Underground Conductors	358.0	3.27%
GENERAL PLANT (Note 2)		
Structures and Improvements	390.0	2.17%
Office Furniture and Equip.	391.0	3.33%
Transportation Equipment	392.0	2.00%
Stores Equipment	393.0	2.94%
Tools, Shop and Garage Equipment	394.0	3.53%
Laboratory Equipment	395.0	3.57%
Power Operated Equipment	396.0	3.85%
Communications Equipment	397.0	2.86%
AMI - Communications Equipment	397.16	6.67%
Micellaneous Equipment	398.0	4.00%

Reference:

Note 1: These are the weighted average of the depreciation rates in effect for Columbus

Southern Power and Ohio Power prior to the merger of Columbus Southern into Ohio

Power.

Note 2: General Plant depreciation rates were updated as a result of the order issued in Cases No 16-1852-EL-SSO and 16-1853-EL-SSO.

General Note:

AEP will make a 205 filing whenever a company's rates are changed by their commission(s), or if the methodology to calculate the jurisdictional allocator in multiple-state companies changes. Changes in the allocation factors will not necessitate a 205 filing.

AEP EAST COMPANIES

PJM FORMULA RATE

WORKSHEET P - TRANSMISSION DEPRECIATION RATES

EFFECTIVE AS OF 3/6/2019

FOR SINGLE JURISDICTION COMPANIES

WHEELING POWER COMPANY

	PLANT	
	ACCT.	RATES
		Note 1
TRANSMISSION PLANT		
Structures & Improvements	352.0	1.15%
Station Equipment	353.0	2.22%
Towers & Fixtures	354.0	2.65%
Poles & Fixtures	355.0	2.41%
Overhead Conductors	356.0	1.32%
Underground Conduit	357.0	9.94%
Underground Conductors	358.0	13.98%
Trails & Roads	359.0	-
GENERAL PLANT		
Structures and Improvements	390.0	1.08%
Office Furniture and Equip.	391.0	2.13%
Stores Equipment	393.0	1.78%
Tools, Shop and Garage Equipment	394.0	1.65.%
Communications Equipment	397.0	5.09%
Micellaneous Equipment	398.0	2.76%

Note 1: Rates Approved in WV Public Service Commission Case No. 18-0645-E-D.

General Note:

AEP will make a 205 filing whenever a company's rates are changed by their commission(s), or if the methodology to calculate the jurisdictional allocator in multiple-state companies changes. Changes in the allocation factors will not necessitate a 205 filing.

AEP East Companies Cost of Service Formula Rate Using Actual/Projected FF1 Balances Worksheet Q – True-up With Interest (Hypothetical Example)

Reconciliation Revenue Requirement For Year 2018 Available May 25, 2019

2018 Revenue Requirement Forecast by October 31, 2017

True-up Adjustment -Over (Under) Recovery

		Over (Under) Recovery Plus Interest	Average Monthly Interest Rate	Months	Calculated Interest	Amortization	Surcharge (Refund) Owed
Interest Rate on Amount of Refun	ds or Surcharges (Note 1))	0.2780%				
An over or under collection will be	e recovered prorata over 2	2018, held for 2019 and returned p	prorata over 2020				
Calculation of Interest					Monthly		
lanuary	Year 2018	-	0.2780%	12			-
February	Year 2018	-	0.2780%	11	-		-
March	Year 2018	-	0.2780%	10	-		-
April	Year 2018	-	0.2780%	9	-		-
May une	Year 2018 Year 2018	-	0.2780% 0.2780%	8 7	-		-
uly	Year 2018	_	0.2780%	6	-		-
August	Year 2018	-	0.2780%	5	-		_
September	Year 2018	-	0.2780%	4	-		-
October	Year 2018	-	0.2780%	3	-		-
November	Year 2018	-	0.2780%	2	-		-
December	Year 2018	-	0.2780%	1 _	-		_
					-		-
					Annual		
anuary through December	Year 2019		0.2780%	12	_		_
	100.2017	-	0.278076	12			
Over (Under) Recovery Plus Interd			0.278076	12	Monthly		
Over (Under) Recovery Plus Interdanuary		ered Over 12 Months	0.2780%	12		_	-
	est Amortized and Recov			12		-	-
anuary ebruary March	Year 2020 Year 2020 Year 2020		0.2780% 0.2780% 0.2780%	12		- - -	-
anuary Gebruary March April	Year 2020 Year 2020 Year 2020 Year 2020 Year 2020 Year 2020		0.2780% 0.2780% 0.2780% 0.2780%	12		- - -	-
anuary Tebruary March April May	Year 2020		0.2780% 0.2780% 0.2780% 0.2780% 0.2780%	12		- - - -	-
anuary Gebruary March April May une	Year 2020		0.2780% 0.2780% 0.2780% 0.2780% 0.2780% 0.2780%	12		- - - - -	- - - - -
anuary February Aarch April Aay une	Year 2020		0.2780% 0.2780% 0.2780% 0.2780% 0.2780% 0.2780%	12			- - - - - -
anuary february March April May une uly	Year 2020		0.2780% 0.2780% 0.2780% 0.2780% 0.2780% 0.2780% 0.2780%	12		- - - - - - -	
anuary Sebruary March April May une uly August eptember	Year 2020		0.2780% 0.2780% 0.2780% 0.2780% 0.2780% 0.2780%	12			
anuary february March April May une ully August eptember	Year 2020		0.2780% 0.2780% 0.2780% 0.2780% 0.2780% 0.2780% 0.2780% 0.2780%	12			
anuary ebruary March	Year 2020		0.2780% 0.2780% 0.2780% 0.2780% 0.2780% 0.2780% 0.2780% 0.2780% 0.2780%	12			
ebruary flarch April Auy une ully August eptember October	Year 2020		0.2780% 0.2780% 0.2780% 0.2780% 0.2780% 0.2780% 0.2780% 0.2780% 0.2780% 0.2780%	-			
ebruary flarch April Auy une ully August eptember October	Year 2020		0.2780% 0.2780% 0.2780% 0.2780% 0.2780% 0.2780% 0.2780% 0.2780% 0.2780% 0.2780%	-			

Total Interest

Note 1: The interest rate to be applied to the over recovery or under recovery amounts will be determined using the average monthly FERC interest rate (as determined pursuant to 18 C.F.R. section 35.19a) for the twenty (20) months from the beginning of the rate year being trued-up through August 31 of the following year.

ATTACHMENT H-20

Annual Transmission Rates – AEP Transmission Companies (AEPTCo)¹ In the AEP Zone

- 1. The annual transmission revenue requirement is equal to the results of the AEPTCo formula and its associated attachments shown in Attachment H-20B posted on the PJM Internet site ("Formula Rate") which reflects the facilities within PJM and the associated revenue requirements of AEPTCo. The rates determined pursuant to Attachment H-20B shall be implemented pursuant to the Formula Rate Implementation Protocols set forth in Attachment H-20A.
- 2. **Determination of monthly charges for AEP Zone:** On a monthly basis, revenue credits shall be calculated based on the sum of AEPTCo's share of revenues collected during the month from: (i) the PJM Border Rate under Schedule 7; (ii) Network Integration Transmission Service to Non-Zone Network Load under Attachment H-A; and (iii) Firm Point-To-Point Transmission Service where the Point of Delivery is internal to the AEP Zone. The sum of these revenue credits and potential charges will appear as an adjustment (reduction) to the gross monthly rate stated above on a Transmission Customer's bill in that month for service under this schedule.
- 3. The revenue requirement in (1) shall be effective until amended by AEPTCo or modified by the Commission.
- 4. In addition to the rate set forth in section (1) above, the Network Customer purchasing Network Integration transmission Service shall pay for transmission congestion charges, and any other applicable charges, in accordance with the provisions of this Tariff, and any amounts necessary to reimburse the Transmission Owners for any amounts payable to them as sales, excise, "btu," carbon, value-added, or similar taxes (other than taxes based upon or measured by net income) with respect to the amounts payable pursuant to the Tariff.

AEPTCo subsidiaries in PJM include 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.

ATTACHMENT H-20 A

THE AEP TRANSMISSION COMPANIES IN THE AEP ZONE FORMULA RATE IMPLEMENTATION PROTOCOLS

The formula rate template ("Template"), and these formula rate implementation protocols ("Protocols") together comprise the filed rate ("Formula Rate") of 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. (collectively "AEPTCo") for transmission revenue requirement determinations under the PJM Interconnection, LLC ("PJM") Open Access Transmission Tariff ("PJM Tariff"). AEPTCo shall follow the instructions specified in the Formula Rate to calculate annually its net annual transmission revenue requirement, as set forth at Attachment H-20B, page 1, line 4 of the Template ("Net Revenue Requirement"). The Net Revenue Requirement shall be determined for January 1 to December 31 of a given calendar year (the "Rate Year"). The Formula Rate shall become effective for recovery of AEPTCo's Net Revenue Requirement upon the effective date for incorporation into the PJM Tariff through a filing with the Federal Energy Regulatory Commission ("FERC" or "Commission") under Section 205 of the Federal Power Act ("FPA"), 16 U.S.C. § 824d.

Section 1. <u>Annual Projection</u>

a. No later than October 31 preceding a Rate Year, and each subsequent Rate Year,

AEPTCo shall determine its projected Net Revenue Requirement for the upcoming Rate

Year in accordance with the Formula Rate ("Annual Projection"). The Annual Projection

shall include the True-Up Adjustment described and defined in Section 2 below, if

applicable. AEPTCo shall cause an electronic version of the Annual Projection to be

posted in both a Portable Document Format ("PDF") and fully-functioning Excel file at a

publicly accessible location on PJM's internet website and OASIS. The date on which the posting occurs shall be that year's "Annual Projection Publication Date."

- The posting of the Annual Projection shall: b.
 - (i) Provide the Formula Rate calculations and all inputs thereto, as well as supporting documentation and workpapers for data that are used in the projected Net Revenue Requirement;
 - Include all inputs in sufficient detail to identify the components of AEPTCo's (ii) projected Net Revenue Requirement, explanations of the bases for the projections and input data, and sufficient detail and explanation to enable Interested Parties² to replicate the calculation of the projected Net Revenue Requirement;
 - (iii) With respect to any Accounting Changes (as that term is defined in Section 3.e.iii)
 - Identify any Accounting Changes including: Α.
 - i. The initial implementation of an accounting standard or policy;
 - ii. The initial implementation of accounting practices for unusual or unconventional items where FERC has not provided specific accounting direction;
 - iii. Correction of errors and prior period adjustments that impact the projected Net Revenue Requirement calculation;
 - iv. The implementation of new estimation methods or policies that change prior estimates; and

² As used in these Protocols, "Interested Parties" shall include but not be limited to: (i) any Eligible Customer under the PJM Tariff; (ii) any regulatory agency with rate jurisdiction over a public utility located within the PJM footprint; (iii) any consumer advocate authorized by state law to review and contest the rates for any such public utility; and (iv) any party with standing under FPA section 205 or section 206.

- v. Changes to income tax elections;
- B. Identify items included in the projected Net Revenue Requirement at an amount other than on a historic cost basis (e.g., fair value adjustments);
- C. Identify any reorganization or merger transaction during the previous year and explain the effect of the accounting for such transaction(s) on inputs to the projected Net Revenue Requirement; and
- Provide, for each item identified pursuant to Section 1.b.iii.A C of these
 Protocols, a narrative explanation of the individual impact of such changes
 on the projected Net Revenue Requirement.
- (iv) Include the following information related to affiliate cost allocation:
 - A. A detailed description of the methodologies used to allocate and directly assign costs between AEP and its affiliates by service category or function, including any changes to such cost allocation methodologies from the prior year, and the reasons for those changes; and
 - B. The magnitude of such costs that have been allocated or directly assigned between AEP and each affiliate by service category or function.
- c. If the date for making the posting of the Annual Projection should fall on a weekend or a holiday recognized by FERC, then the posting shall be made no later than the next business day.³ Within five (5) calendar days of the posting, PJM shall provide notice of such posting via the PJM Members Committee email subscription ("PJM Exploder List"). Interested Parties can subscribe to the PJM Exploder List on the PJM website.

³ For the purposes of these Protocols, if any deadline included in these Protocols should fall on a weekend or a holiday recognized by FERC, then the deadline shall be extended to no later than the next business day.

- d. Together with the posting of the Annual Projection, AEPTCo shall cause to be posted on the PJM internet website and OASIS, and distributed to the PJM Exploder List, the time, date, location, and remote-access information for a stakeholder meeting with Interested Parties in order for AEPTCo to explain its Annual Projection and to provide Interested Parties an opportunity to seek information and clarifications regarding the Annual Projection ("Annual Projection Meeting"). The Annual Projection Meeting shall be held no less than twenty (20) business days and no more than thirty (30) business days after the posting of the Annual Projection. Notice of the Annual Projection Meeting shall be provided via the PJM Exploder List no less than seven (7) calendar days prior to the meeting. AEPTCo will provide remote access to the Annual Projection Meeting in order to ease burdens (e.g. travel costs) to ensure all Interested Parties have the opportunity to participate.
- e. To the extent AEPTCo agrees to make changes in the Annual Projection for a given Rate Year, such revised Annual Projection shall be promptly posted at a publicly accessible location on PJM's internet website and OASIS, and e-mailed to the PJM Exploder List. Changes posted prior to November 30 preceding the Rate Year, or the next business day if November 30 is not a business day (or such later date as can be accommodated under PJM's billing practices), shall be reflected in the Annual Projection for the Rate Year; changes posted after that date will be reflected, as appropriate, in the True-Up Adjustment for the Rate Year.
- f. The Annual Projection, including the True-Up Adjustment, for each Rate Year shall be subject to review, challenge, true-up, and refunds or surcharges with interest, to the extent and in the manner provided in these Protocols.

Section 2. <u>True-Up Adjustment</u>

AEPTCo will calculate the amount of under- or over-collection of its actual Net Revenue Requirement during the preceding Rate Year ("True-Up Adjustment") after the FERC Form No. 1 data for that Rate Year has been filed with the Commission. The True-Up Adjustment shall be the sum of the True-Up Adjustment Over/Under Recovery as determined in Section 2(a) and the Interest on the True-Up Adjustment Over/Under Recovery as determined in Section 2(b):

a. AEPTCo's projected Net Revenue Requirement collected during the previous Rate Year⁴ will be compared to AEPTCo's actual Net Revenue Requirement for the previous Rate Year calculated in accordance with AEPTCo's Formula Rate and based upon (i)

AEPTCo's FERC Form No. 1 for that same Rate Year, (ii) any FERC orders specifically applicable to AEPTCo's calculation of its annual revenue requirement, (iii) the books and records of AEPTCo (which shall be maintained consistent with the FERC Uniform System of Accounts ("USofA")), (iv) FERC accounting policies and practices applicable to the calculation of annual revenue requirements under formula rates, and (v) any aspects of the PJM Tariff Governing Documents that apply to the calculation of annual

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⁴ If the initial use of this Formula Rate covers only part of a calendar year, the initial projected annual Net Revenue Requirement will be divided by 12 to calculate the monthly projected cost of service to be collected each month it is effective that first year. Similarly, the actual Net Revenue Requirement will be divided by 12 to calculate the actual monthly cost of service to be collected during those same months of that year. Similar calculations of projected Net Revenue Requirement and actual Net Revenue Requirement will be made for the months prior to the effective date of this Formula Rate using the previous formula rate in effect during those months. The actual Net Revenue Requirements computed under each of the two formula rate periods that initial Rate Year will be added together to obtain the total actual Net Revenue Requirement. The first True-up Adjustment will compare this total actual Net Revenue Requirement to the Net Revenue Requirement collected under the two formulas for that initial Rate Year.

- revenue requirements under individual transmission owner formula rates,⁵ to determine any over- or under-recovery ("True-Up Adjustment Over/Under Recovery").
- b. Interest on any True-Up Adjustment Over/Under Recovery shall be calculated for the thirty-six (36) months during which the over or under recovery in the revenue requirement remains outstanding (*i.e.*, from January 1 of the Rate Year being trued-up through December 31 of the year in which the True-Up Adjustment Over/Under recovery is credited or collected). The interest rate to be applied to the True-Up Adjustment Over/Under Recovery amounts will be determined using the average monthly FERC Interest Rate (as determined pursuant to 18 C.F.R. § 35.19a) for the twenty (20) months from the beginning of the Rate Year being trued-up through August 31 of the following year.

Section 3. <u>Annual Update</u>

- a. On or before May 25 following each Rate Year, AEPTCo shall calculate its actual Net Revenue Requirement and the True-Up Adjustment as described in Section 2 ("Annual Update") for such Rate Year and, together with such other information described in this Section 3, shall cause such Annual Update to be posted, in both a PDF and fully-functioning Excel format, at a publicly accessible location on PJM's internet website and OASIS. Within five (5) calendar days of such posting, PJM shall provide notice of such posting via the PJM Exploder List.
- b. If the date for making the Annual Update posting should fall on a weekend or a holiday recognized by the FERC, then the posting shall be due on the next business day.

⁵ PJM Tariff Governing Documents include the PJM Tariff, Bylaws, Criteria, and Membership Agreements.

- The date on which the posting occurs shall be that year's "Annual Update Publication c. Date."
- d. Together with the posting of the Annual Update, AEPTCo shall cause to be posted on the PJM website and OASIS the time, date, location, and remote-access information for a stakeholder meeting with Interested Parties in order for AEPTCo to explain its Annual Update and to provide Interested Parties an opportunity to seek information and clarifications regarding the Annual Update ("Annual Update Meeting"). Notice of the Annual Update Meeting shall be provided via the PJM Exploder List no less than seven (7) calendar days prior to the meeting. The Annual Update Meeting shall be held no less than twenty (20) business days and no more than thirty (30) business days after the Annual Update Publication Date. AEPTCo will provide remote access to the Annual Update Meeting in order to ease burdens (e.g. travel costs) to ensure all Interested Parties have the opportunity to participate.
- The Annual Update posting for the Rate Year: e.
 - Shall provide, via the Formula Rate worksheets, sufficiently detailed supporting (i) documentation for data (and all adjustments thereto or allocations thereof) used in the Formula Rate that are not stated in the FERC Form No. 1;6
 - (ii) Shall provide sufficient detail and sufficient explanation to enable Interested Parties to replicate the calculation of the Annual Update results from the FERC

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⁶ It is the intent of the Formula Rate, including the supporting explanations and allocations described therein, that each input to the Formula Rate for purposes of determining the actual Net Revenue Requirement for a given Rate Year will be either taken directly from the FERC Form No. 1 or reconcilable to the FERC Form No. 1 by the application of clearly identified and supported information. If the referenced form is superseded, the successor form(s) shall be utilized and supplemented as necessary to provide equivalent information as that provided in the superseded form. If the referenced form is discontinued, equivalent information as that provided in the discontinued form shall be utilized.

Form No. 1 and verify that each input to the Template is consistent with the requirements of the Formula Rate;

(iii) Shall identify:

- A. Any change in accounting that affects inputs to the Template or the resulting charges billed under the Formula Rate ("Accounting Change"), including:
 - i. The initial implementation of an accounting standard or policy;
 - The initial implementation of accounting practices for unusual or unconventional items where FERC has not provided specific accounting direction;
 - iii. Correction of errors and prior period adjustments that impact theTrue-Up Adjustment calculation;
 - iv. The implementation of new estimation methods or policies that change prior estimates; and
 - v. Changes to income tax elections;
- B. Any items included in the Annual Update at an amount other than on a historic cost basis (e.g., fair value adjustments);
- C. Any reorganization or merger transaction during the previous year and an explanation of the effect of the accounting for such transaction(s) on inputs to the Annual Update;
- D. For each item identified pursuant to Sections 3.e.iii.A C of these
 Protocols, the individual impact (in narrative format) of such changes on the Annual Update.

- (iv) Shall be subject to review and challenge in accordance with the procedures set forth in Sections 4, 5, and 6 of these Protocols.
- (v) Shall be subject to review and challenge in accordance with the procedures set forth in these Protocols with respect to the prudence of any costs and expenditures included for recovery in the Annual Update; provided, however, that nothing in these Protocols is intended to modify the Commission's applicable precedent with respect to the burden of going forward or burden of proof under formula rates in such prudence challenges; and
- (vi) Shall not seek to modify the Formula Rate and shall not be subject to challenge by any Interested Party seeking to modify the Formula Rate (i.e., any modifications to the Formula Rate will require, as applicable, an FPA section 205 or section 206 filing or initiation of a section 206 investigation).
- f. The following Formula Rate inputs shall be stated values to be used in the Formula Rate until changed pursuant to an FPA section 205 or section 206 proceeding: (i) rate of return on common equity ("ROE"); (ii) the depreciation and/or amortization rates as set forth in Attachment 10 to the Formula Rate template, and (iii) Post-Employment benefits other than Pension ("PBOP") charges pursuant to Statement of Financial Accounting Standards No. 106, Employers' Accounting for Postretirement Benefits Other Than Pensions.
- g. Example Timelines for 2018 Annual Projection and 2019 Annual Update:
 On or before October 31, 2017, AEPTCo will determine the projected Net Revenue
 Requirement for the 2018 Rate Year. AEPTCo will post the Annual Projection for the
 2018 Rate Year in accordance with Section 1 above. On or before May 25, 2019,

AEPTCo will post its Annual Update, consisting of the actual Net Revenue Requirement and True-Up Adjustment for the 2018 Rate Year determined pursuant to Section 2 above. Such True-Up Adjustment will be reflected in the Annual Projection of the Net Revenue Requirement for the 2020 Rate Year posted on or before October 31, 2019.

Section 4. Annual Review Procedures

Each Annual Update and Annual Projection shall be subject to the following review procedures ("Annual Review Procedures"):

- a. Interested Parties shall have up to the later of two-hundred-ten (210) calendar days after the applicable Publication Date, or thirty (30) calendar days after the receipt of all responses to timely submitted information requests (unless such period is extended with the written consent of AEPTCo or by FERC order) ("Review Period"), to review the calculations and to notify AEPTCo in writing of any specific challenges to the Annual Update or Annual Projection ("Preliminary Challenge"), including challenges related to Accounting Changes. An Interested Party submitting a Preliminary Challenge must specify the inputs, supporting explanations, allocations, calculations, or other information to which it objects, and provide an appropriate explanation and documents to support its challenge. AEPTCo shall cause to be posted all Preliminary Challenges at a publicly accessible location on PJM's internet website and OASIS, and a link to the website will be e-mailed to the PJM Exploder List.
- b. In the event of a Preliminary Challenge, AEPTCo will appoint a senior representative to work with the Interested Party (or its representatives) toward a resolution of the dispute.

- c. AEPTCo shall respond in writing to a Preliminary Challenge within twenty (20) business days of receipt, and its response shall notify the challenging party of the extent to which AEPTCo agrees or disagrees with the challenge. If AEPTCo disagrees with the Preliminary Challenge, it will provide the Interested Party with an explanation supporting the challenged inputs, explanations, allocations, calculations, or other information. AEPTCo shall promptly cause to be posted its responses to all Preliminary Challenges at a publicly accessible location on PJM's internet website and OASIS, and a link to the website will be e-mailed to the PJM Exploder List. Notwithstanding the foregoing, Preliminary Challenges and responses to Preliminary Challenges that include material deemed by AEPTCo to be confidential information will not be publicly posted but will be made available to requesting parties pursuant to a confidentiality agreement to be executed by AEPTCo and the requesting party.
- d. AEPTCo shall respond to all Preliminary Challenges submitted during the Review Period by no later than thirty (30) calendar days after the end of the Review Period.
- e. Interested Parties shall have up to one-hundred-fifty (150) calendar days after each annual Publication Date (unless such period is extended with the written consent of AEPTCo or by FERC order) to serve reasonable information requests on AEPTCo ("Discovery Period").
- f. Information requests shall be limited to what is necessary to determine: (i) the extent, effect, or impact of an Accounting Change; (ii) whether the Annual Update or Annual Projection fails to include data properly recorded in accordance with the Protocols; (iii) the proper application of the Template and procedures in the Protocols; (iv) the accuracy of data and consistency with the Formula Rate of the charges shown in the Annual

Update or Annual Projection; (v) the prudence of the actual costs and expenditures, including procurement methods and cost control methodologies; (vi) the effect of any change to the underlying USofA or FERC Form No. 1; and (vii) any other information that may reasonably have substantive effect on the calculation of the charge pursuant to the Formula Rate. The information requests shall not otherwise be directed to ascertaining whether the Formula Rate is just and reasonable. Information requests shall not solicit information concerning costs or allocations where the costs or allocation methods have been determined to be appropriate by FERC in the context of prior AEPTCo Annual Updates, except that such information requests shall be permitted if they (i) seek to determine if there has been a change in circumstances, (ii) are in connection with corrections pursuant to Section 6 of these Protocols, or (iii) relate to costs or allocations that have not previously been challenged and adjudicated by FERC. AEPTCo shall make a good faith effort to respond to reasonable information requests pertaining to the Annual Update or Annual Projection within fifteen (15) business days of receipt of such requests. AEPTCo shall respond to all reasonable information requests no later than thirty (30) calendar days after the end of the Discovery Period. AEPTCo will cause to be posted on the PJM website and OASIS all information requests from Interested Parties and AEPTCo's response(s) to such requests, and a link to the website will be e-mailed to the PJM Exploder List. Notwithstanding the foregoing, information and document requests and responses to information and document requests that include material deemed by AEPTCo to be confidential information will not be publicly posted but will be made available to requesting parties pursuant to a confidentiality agreement to

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- be executed by AEPTCo and the requesting party. Voluminous materials will be made available at a physical AEP site.
- h. AEPTCo shall not claim that responses to information and document requests provided pursuant to these Protocols are subject to any settlement privilege in any subsequent FERC proceeding addressing AEPTCo's Annual Update or Annual Projection.
- i. To the extent AEPTCo and any Interested Party(ies) are unable to resolve disputes related to information requests submitted in accordance with these Annual Review Procedures, AEPTCo or the Interested Party may petition the FERC to appoint an Administrative Law Judge as a discovery master to resolve the discovery dispute(s) in accordance with these Protocols and consistent with the FERC's discovery rules.
- j. Preliminary Challenges or Formal Challenges (as described in Sections 4 and 5) related to Accounting Changes shall be treated in the same manner under these Protocols as other challenges to the Annual Update or Annual Projection. Failure to make a Preliminary Challenge with respect to an Accounting Change in an Annual Update or Annual Projection shall not act as a bar with respect to a Formal Challenge with respect to that Annual Update or Annual Projection provided that the Interested Party submitted a Preliminary Challenge with respect to one or more other issues. Nor shall such failure bar a subsequent Preliminary Challenge related to a subsequent Annual Update or Annual Projection to the extent such Accounting Change affects the subsequent Annual Update or Annual Projection.
- k. If a change made by AEPTCo to its accounting policies, practices, or procedures, or the application of the Formula Rate, is found by the FERC to be unjust, unreasonable, or unduly discriminatory or preferential, then the calculation of the charges to be assessed

during the Rate Year then under review, and the charges to be assessed during any subsequent Rate Years, including any True-up Adjustments, shall not include such change, but shall include any remedy that may be prescribed by FERC in the exercise of its discretion as of the effective date of such remedy, to ensure that the Formula Rate continues to operate in a manner that is just, reasonable, and not unduly discriminatory or preferential.

Section 5. Resolution of Challenges

- a. Interested Parties shall have up to two –hundred-seventy (270) days following the applicable Publication Date (unless such period is extended with the written consent of AEPTCo or by FERC order), to file a challenge with the FERC ("Formal Challenge"). Such Formal Challenge shall be submitted in the same docket as the AEPTCo informational filing and shall be served on AEPTCo by electronic service on the date of such filing in accordance with Section 385.2010(f)(3) of the Commission's regulations. Subject to any applicable confidentiality and Critical Energy Infrastructure Information restrictions, all information and correspondence produced by AEPTCo pursuant to these Protocols may be included in any Formal Challenge or other FERC proceeding relating to the Formula Rate.
- b. Formal Challenges are to be filed pursuant to these Protocols, rather than under rule 206, and shall:
 - (i) Clearly identify the action or inaction which is alleged to violate the Formula Rate Template or Protocols;
 - (ii) Explain how the action or inaction violates the filed rate Template or Protocols;

- (iii) Set forth the business, commercial, economic or other issues presented by the action or inaction as such relate to or affect the party filing the Formal Challenge, including
 - A. The extent or effect of an Accounting Change;
 - B. Whether the Annual Update or Annual Projection fails to include data properly recorded in accordance with these Protocols;
 - C. The proper application of the Template and procedures in these Protocols;
 - D. The accuracy of the data and consistency with the Formula Rate of the charges shown in the Annual Update or Annual Projection;
 - E. The prudence of actual costs and expenditures;
 - F. The effect of any change to the underlying Uniform System of Accounts or the FERC Form No. 1; or
 - G. Any other information that may reasonably have substantive effect on the calculation of the charge pursuant to the Template.
- (iv) Make a good faith effort to quantify the financial impact or burden (if any) created for the party filing the Formal Challenge as a result of the action or inaction;
- (v) State whether the issues presented are pending in an existing Commission proceeding or a proceeding in any other forum in which the filing party is a party, and if so, provide an explanation why timely resolution cannot be achieved in that forum;

- (vi) State the specific relief or remedy requested, including any request for stay or extension of time, and the basis for that relief;
- (vii) Include all documents that support the facts in the Formal Challenge in possession of, or otherwise attainable by, the filing party, including, but not limited to, contracts and affidavits; and
- (viii) State whether the filing party utilized the Preliminary Challenge procedures described in these Protocols to dispute the action or inaction raised by the Formal Challenge, and, if not, describe why not.
- c. Preliminary and Formal Challenges shall be limited to issues that may be necessary to determine: (i) the extent or effect of an Accounting Change; (ii) whether the Annual Update or Annual Projection fails to include data properly recorded in accordance with these Protocols; (iii) the proper application of the Formula Rate and procedures in these Protocols; (iv) the accuracy of data and consistency with the Formula Rate of the calculations shown in the Annual Update and Annual Projection; (v) the prudence of actual costs and expenditures; (vi) the effect of any change to the underlying Uniform System of Accounts or FERC Form No. 1; or (vii) any other information that may reasonably have substantive effect on the calculation of the charge pursuant to the formula.
- d. Failure to raise an issue in a Preliminary Challenge shall not bar an Interested Party
 from raising that issue in a Formal Challenge, provided the Interested Party submitted a
 Preliminary Challenge during the Review Period with respect to one or more other
 issues. Failure to pursue an issue through a Preliminary Challenge or to lodge a Formal
 Challenge regarding any issue as to a given Annual Update shall bar pursuit of such

issue with respect to that Annual Update, but shall not bar pursuit of such issue or the lodging of a Formal Challenge as to such issue as it relates to a subsequent Annual Update.

- e. Any response by AEPTCo to a Formal Challenge must be submitted to the FERC within thirty (30) calendar days of the date of the filing of the Formal Challenge, and shall be served on the filing party(ies) and the PJM Exploder List on the date of such filing.
- f. In any Formal Challenge proceeding concerning an Annual Update (including corrections), Annual Projection, or Accounting Change(s), AEPTCo shall demonstrate the justness and reasonableness of the rate resulting from its application of the Formula Rate by demonstrating that it has correctly applied the terms of the Formula Rate consistent with these Protocols and that it followed the applicable requirements and procedures in applying the Formula Rate. Nothing herein is intended to alter the burdens applied by FERC with respect to prudence challenges.
- g. Except as specifically provided herein, nothing herein shall be deemed to limit in any way the right of AEPTCo to file unilaterally, pursuant to section 205 of the FPA and the regulations thereunder, an application seeking changes to the Formula Rate or to any of the stated value inputs requiring a section 205 filing under these Protocols (including, but not limited to, ROE and depreciation and amortization rates), or the right of any other party or the Commission to seek such changes pursuant to section 206 of the FPA and the regulations thereunder.
- h. AEPTCo may, at its discretion and at a time of its choosing, make a limited filing pursuant to section 205 to modify stated values in the Formula Rate (i) for amortization and depreciation rates, (ii) to correct obvious errors or omissions in the Formula Rate

such as would result from changes to the FERC Form No. 1, or (iii) PBOP charges pursuant to Statement of Financial Accounting Standards No. 106, Employers' Accounting for Postretirement Benefits Other Than Pensions. The sole issue in any such limited section 205 proceeding shall be whether such proposed change(s) is just and reasonable, and it shall not address other aspects of the Formula Rate or impose upon AEPTCo any burden with respect to such other aspects of the Formula Rate.

Section 6. Changes to Annual Updates

If AEPTCo determines or concedes that corrections to the Annual Update are required, whether under Sections 4 or 5 of these Protocols, including but not limited to those requiring corrections to its FERC Form No. 1, or input data used for a Rate Year that would have affected the Annual Update for that Rate Year, such corrections shall be reflected as adjustments in the Annual Update for the next Rate Year, with interest calculated in accordance with the FERC Interest Rate (as determined pursuant to 18 C.F.R. § 35.19a). This reconciliation mechanism shall apply in lieu of mid-Rate Year adjustments.

AEPTCo subsidiaries in PJM Cost of Service Formula Rate Using Actual/Projected FF1 Balances Worksheet A Rate Base Company Name

			Gross Pla	ant In Servi	ce	
Line No	Month	Transmission	Transmission ARO	General	General ARO	Intangible
	(a)	(d)	(e)	(h)	(i)	(j)
				FF1,	FF1, page 207	FF1, page 205
		FF1, page 207	FF1, page 207	page 207 Col.(g) &	Col.(g) &	Col.(g) &
		Col.(g) & pg.	Col.(g) & pg.	pg. 206	pg. 206	pg. 204
		206 Col. (b),	206 Col. (b),	Col. (b),	Col. (b), ln	Col. (b), ln
	(Note A)	ln 58	ln 57	ln 99	98	5
1	December Prior to Rate Year					
2	January					
3	February					
4	March					
5	April					
6	May					
7	June					
8	July					
9	August					
10	September					
11	October					
12	November					
13	December of Rate Year					
	Average of the 13 Monthly					
14	Balances	-	-	-	-	-

			Accumula	ted Deprecia	tion	
Line No	Month	Transmission	Transmissio n ARO	General	General ARO	Intangible
	(a)	(d)	(e)	(h)	(i)	(j)
			Company Records		Company Records (Included	
		FF1, page	(Included in	FF1, page	in total in	FF1, page
		219, ln 25,	total in	219, ln 28,	Column	200, ln 21,
	(Note A)	Col. (b)	Column (d))	Col. (b)	(h))	Col. (b)
15	December Prior to Rate Year					
16	January					
17	February					
18	March					
19	April					
20	May					
21	June					
22	July					
23	August					

24	September						
25	October						
26	November						
27	December of Rate Year						
	Average of the 13 Monthly						
28	Balances	-	-	-	-	-	

Line No	Month (a)	OATT Ancillary Services (GSU) Plant In Service (b) Company Records (included in total in column (d) of	OATT Ancillary Services (GSU) Accumulate d Depreciation (c) Company Records (included in total in column (d) of accumulated	Excluded Plant - Plant In Service (d) Company Records (included in total in column (d) of line 14,	Excluded Plant - Accumula ted Depreciat ion (e) Company Records (included in total in column (d) of line 28, Accumulat ed
	(Note A)	gross plant above)	depreciation above)	Gross Pla nt, above)	Depreciati on, above)
29	December Prior to Rate Year				_
30	January				-
31	February				-
32	March				-
33	April				-
34	May				-
35	June				_
36	July				_
37	August				_
38	September				_
39	October				_
40	November				_
41 42	December of Rate Year Average of the 13 Monthly				-

Balances -	-	-	-	
------------	---	---	---	--

Transmission Accumulated Depreciation net of GSU and other Excludeable Balances (Ln 28d - 42c - 42e) --

<u>Plant</u>	Held For Future Use	Source of Data	Balance @ December 31, 2017	<u>@</u> <u>December</u> 31, 2016	Average Balance for 2017
	(a)	(b)	(c)	(d)	(e)
		FF1, page			
		214, ln 47,			
44	Plant Held For Future Use	Col. (d)	-	-	-
	Transmission Plant Held	Company			
	For Future Use (Included	Records -			
45	in total on line 43)	Note 1	-	_	-

Regulatory Assets and Liabilities

Approved for Recovery In

Ratebase

Note: Regulatory Assets & Liabilities can only be included in ratebase pursuant to a 205 filing with the FERC.



<u>Unfunded Reserves Summary</u> (Company Records)

52	Description	Account				
53a					-	
53b					-	
54		Total	_	_	-	

NOTE 1: On this worksheet, "Company Records" refers to AEP's property accounting ledger.

NOTE 2: The ratebase should not include the

unamoritzed balance of hedging gains or losses.

AEPTCo subsidiaries in PJM Cost of Service Formula Rate Using Actual/Projected FF1 Balances

Worksheet B Supporting ADIT and ITC Balances

		AEPTRANSMISSION	COMPANY		
	(A)	(B)	(C)	(D)	(E)
Line			Balance @		
			<u>December</u>	Balance @ December	Average Balance
Number	<u>Description</u>	Source	<u>31,</u>	31,	for
1	Account 281				
2	Year End Utility Deferrals	FF1, p. 272 - 273, ln 8, Col. (k)			_
3	Less: ARO Related Deferrals	WS B-1 - Actual Stmt. AF Ln. 4 (Note 1)			- -
4	Less: Other Excluded Deferrals	WS B-1 - Actual Stmt. AF Ln. 3 (Note 1)			_
5	Transmission Related Deferrals	Ln 2 - ln 3 - ln 4	-	-	-
6	Account 282				
7	Year End Utility Deferrals	FF1, p. 274 - 275, ln 5, Col. (k)			_
8	Less: ARO Related Deferrals	WS B-1 - Actual Stmt. AF Ln. 7 (Note 1)			_
9	Less: Other Excluded Deferrals	WS B-1 - Actual Stmt. AF Ln. 6 (Note 1)			-
10	Transmission Related Deferrals	Ln 7 - ln 8 - ln 9	-	-	-
11	Account 283				
12	Year End Utility Deferrals	EEL = 276 277 l= 0 C=1 (b)			
13	Less: ARO Related Deferrals	FF1, p. 276 - 277, ln 9, Col. (k) WS B-1 - Actual Stmt. AF Ln. 13 (Note 1)			•
14	Less: Other Excluded Deferrals	WS B-1 - Actual Stmt. AF Ln. 13 (Note 1)			
15	Transmission Related Deferrals	Ln 12 - In 13 - In 14	-	-	
16					
16	Account 190	FF1 2041 0 G 1 ()			
17	Year End Utility Deferrals	FF1, p. 234, ln 8, Col. (c)			-
18	Less: ARO Related Deferrals	WS B-2 - Actual Stmt. AG Ln. 4 (Note 1)			-
19 20	Less: Other Excluded Deferrals Transmission Related Deferrals	WS B-2 - Actual Stmt. AG Ln. 3 (Note 1) Ln 17 - ln 18 - ln 19		_	
20	Transmission Related Defention	En 17 - In 10 - In 19			
21	Account 255				
22	Year End ITC Balances	FF1, p. 266-267, ln 8, Col. (h)			-
23	Less: Balances Not Qualified for Ratebase	Company Records - Note 1			_
24	ITC Balances Includeable in Ratebase	Ln 22 - ln 23	-		-
25	Transmission Related Deferrals	WS B-1 - Actual Stmt. AF Ln. 20 (Note 1)			-
Nome:	On this worksheet, "Company Records" refers to AEP's tax forecast and account proration required by IRS Letter Rule Section 1.167(I)-I(h)(6)(ii). Line item det	ing ledger. The PRTR will use projected ending balances and reflect ail of actual deferred tax items will be included on Worksheets B-1 and B-			
NOTE 1	2.				
NOTE 2	ADIT balances should exclude balances related to hedging activity.				

Company Name SPECIFIED DEFERRED CREDITS - Actual Cycle Only PERIOD ENDED DECEMBER 31, 2017

(DEBIT) CREDIT

	<u>COLUMN A</u>	COLUMN B	COLUMN C	COLUM N D	COLUM N E	COLUMN <u>F</u>	COLUM N G	COLUMN <u>H</u>	COLUMN <u>I</u>	COLUM N J	COLUMN <u>K</u>	COLUMN L	COLUM N M	COLUMN <u>N</u>	COLUMN O
		PER BO	OOKS	APPLICA	<u>ON-</u> BLE/NON- LITY	AVERAGE	FUNCTIO)NALIZATION	AVERAGE	FUNCTIO	ONALIZATION	12/31/2016	FUNCTIO	ONALIZATION	12/31/2017
	ACCUMULATED DEFERRED FIT ITEMS	BALANCE AS <u>OF 12-31-</u> 2016	BALANCE AS OF 12-31- 2017	BALANC E AS OF 12-31- 2016	BALANC E AS OF 12-31- 2017	UTILITY (B+C+D+E)/2	GENER ATION	TRANSMI SSION	<u>DISTRIB</u> <u>UTION</u>	GENER ATION	TRANSMI SSION	DISTRIB UTION	GENER ATION	TRANSMI SSION	<u>DISTRIB</u> <u>UTION</u>
1.00	ACCOUNT 281:														
2.01		0	0			0	0	0	0						
2.03 2.04		0	0	0	0	0									
2.05		0	0	0	0	0									
2.06		0	0	0	0	0							. <u></u>		
3	TOTAL ACCOUNT 281 ACCOUNT 281 - ARO-Related	0	0	0	0	0	0	0	0	0	0	0	0	0	0
4	Deferrals	0	0	0	0	0	0	0	0	0	0	0	0	0	0
5	ACCOUNT 282:														
5.01		0	0			0	0	0	0						
5.02		0	0			0	0	0	0						
5.03		0	0			0	0	0	0						
5.04		0	0			0	0	0	0						
5.05		0	0			0	0	0	0						

5.0	06	0	0	0	0	0	0
5.0	07	0	0	0	0	0	0
5.0	08	0	0	0	0	0	0
5.0	09	0	0	0	0	0	0
5.	10	0	0	0	0	0	0
5.	11	0	0	0	0	0	0
5.	12	0	0	0	0	0	0
5.	13	0	0	0	0	0	0
5.	14	0	0	0	0	0	0
5.	15	0	0	0	0	0	0
5.	16	0	0	0	0	0	0
5.	17	0	0	0	0	0	0
5.	18	0	0	0	0	0	0
5.	19	0	0	0	0	0	0
5.3	20	0	0	0	0	0	0
5.3	21	0	0	0	0	0	0
5.3	22	0	0	0	0	0	0
5.3	23	0	0	0	0	0	0
5.3	24	0	0	0	0	0	0
5.3	25	0	0	0	0	0	0
5.3	26	0	0	0	0	0	0
5.3	27	0	0	0	0	0	0
5.3	28	0	0	0	0	0	0
5.3	29	0	0	0	0	0	0
5.3	30	0	0	0	0	0	0
5.3	31	0	0	0	0	0	0
5.3	32	0	0	0	0	0	0
5.3	33	0	0	0	0	0	0
5.3	34	0	0	0	0	0	0
5.3	35	0	0	0	0	0	0
5.3	36	0	0	0	0	0	0
5.3	37	0	0	0	0	0	0
5.3	38	0	0	0	0	0	0

5.39				0	0	0									
5.40				0	0	0									
5.41				0	0	0									
6	TOTAL ACOUNT 282 ACCOUNT 282 - ARO-Related	0	0	0	0	0	0	0	0	0	0	0	0	0	0
7	Deferals	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	A COOLDIT AND														
8	ACCOUNT 283:														
9.01		0	0			0	0	0	0						
9.02		0	0			0	0	0	0						
9.03		0	0			0	0	0	0						
9.04		0	0			0	0	0	0						
9.05		0	0			0	0	0	0						
9.06		0	0			0	0	0	0						
9.07		0	0			0	0	0	0						
9.08		0	0			0	0	0	0						
9.09		0	0			0	0	0	0						
9.10		0	0			0	0	0	0						
9.11		0	0			0	0	0	0						
9.12		0	0			0	0	0	0						
9.13		0	0			0	0	0	0						
9.14		0	0			0	0	0	0						
9.15		0	0			0	0	0	0						
9.16		0	0			0	0	0	0						
9.17		0	0			0	0	0	0						
9.18		0	0			0	0	0	0						
9.19		0	0			0	0	0	0						
9.20		0	0			0	0	0	0						
9.21		0	0			0	0	0	0						
9.22		0	0			0	0	0	0						
9.23		0	0			0	0	0	0						

9.24	0	0	0	0	0	0
9.25	0	0	0	0	0	0
9.26	0	0	0	0	0	0
9.27	0	0	0	0	0	0
9.28	0	0	0	0	0	0
9.29	0	0	0	0	0	0
9.30	0	0	0	0	0	0
9.31	0	0	0	0	0	0
9.32	0	0	0	0	0	0
9.33	0	0	0	0	0	0
9.34	0	0	0	0	0	0
9.35	0	0	0	0	0	0
9.36	0	0	0	0	0	0
9.37	0	0	0	0	0	0
9.38	0	0	0	0	0	0
9.39	0	0	0	0	0	0
9.40	0	0	0	0	0	0
9.41	0	0	0	0	0	0
9.42	0	0	0	0	0	0
9.43	0	0	0	0	0	0
9.44	0	0	0	0	0	0
9.45	0	0	0	0	0	0
9.46	0	0	0	0	0	0
9.47	0	0	0	0	0	0
9.48	0	0	0	0	0	0
9.49	0	0	0	0	0	0
9.50	0	0	0	0	0	0
9.51	0	0	0	0	0	0
9.52	0	0	0	0	0	0
9.53	0	0	0	0	0	0
9.54	0	0	0	0	0	0
9.55	0	0	0	0	0	0
9.56	0	0	0	0	0	0
7.50	Ü	U	U	v	U	U

9.57	0	0	0	0	0	0
9.58	0	0	0	0	0	0
9.59	0	0	0	0	0	0
9.60	0	0	0	0	0	0
9.61	0	0	0	0	0	0
9.62	0	0	0	0	0	0
9.63	0	0	0	0	0	0
9.64	0	0	0	0	0	0
9.65	0	0	0	0	0	0
9.66	0	0	0	0	0	0
9.67	0	0	0	0	0	0
9.68	0	0	0	0	0	0
9.69	0	0	0	0	0	0
9.70	0	0	0	0	0	0
9.71	0	0	0	0	0	0
9.72	0	0	0	0	0	0
9.73	0	0	0	0	0	0
9.74	0	0	0	0	0	0
9.75	0	0	0	0	0	0
9.76	0	0	0	0	0	0
9.77	0	0	0	0	0	0
9.78	0	0	0	0	0	0
	0					
9.79		0	0	0	0	0
9.80	0	0	0	0	0	0
9.81	0	0	0	0	0	0
9.82	0	0	0	0	0	0
9.83	0	0	0	0	0	0
9.84	0	0	0	0	0	0
9.85	0	0	0	0	0	0
9.86	0	0	0	0	0	0
9.87	0	0	0	0	0	0
9.88	0	0	0	0	0	0
9.89	0	0	0	0	0	0

9.90		0	0			0	0	0	0						
9.91		0	0			0	0	0	0						
9.92		0	0			0	0	0	0						
9.93		0	0			0	0	0	0						
9.94				0	0	0									
9.95				0	0	0									
9.96				0	0	0									
9.97				0	0	0									
9.98				0	0	0									
9.99				0	0	0									
10		0	0	0	0	0	0	0	0	0	0	0	0	0	0
11	DEFD STATE INCOME TAXES	0	0			0	0	0	0						
11.01				0	0	0									
12	TOTAL ACCOUNT 283	0	0	0	0	0	0	0	0	0	0	0	0	0	0
13	ACCOUNT 283 - ARO-Related Deferals	0	0	0	0	0	0	0	0	0	0	0	0	0	0
14	JURISDICTIONAL AMOUNTS FUNCTIONALIZED														
15	TOTAL COMPANY AMOUNTS FUNCTIONALIZED														
	DEFENDATIONALIZED DAGED														
16	REFUNCTIONALIZED BASED ON JURISDICTIONAL PLANT														
	NOTE: DOCT 1070														
17	NOTE: POST 1970 ACCUMULATED DEFERRED														
18	INV TAX CRED. (JDITC) IN A/C 255														
18.01		0	0			0	0	0	0						
18.02		0	0			0	0	0	0						
19															
20	TOTAL ACCOUNT 255	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Company Name ACCUMULATED DEFERRED INCOME TAX IN ACCOUNT 190 - Actual Cycle Only PERIOD ENDED DECEMBER 31, 2017

DEBIT (CREDIT)

	<u>COLUMN A</u>	COLUMN B	COLUMN C	COLUM N D	COLU MN E	COLUMN F	COLUM N G	COLUM N H	COLUM N I	COLUM N J	COLUM N K	COLUM N L	COLUM N M	COLUM N N	COLUM NO
		PER E	BOOKS	NO APPLICAB UTIL	ILE/NON- ITY	AVERAGE ELECTRIC	FUNCTIO	NALIZATION	AVERAGE	FUNCTIO	NALIZATION	12/31/2016	FUNCTI	ONALIZATION	¥ 12/31/2017
		BALANCE AS	BALANCE AS	BALAN CE AS	BALA NCE AS	UTILITY									
	ACCUMULATED DEFERRED FIT ITEMS	OF 12-31- 2016	OF 12-31- 2017	OF 12- 31-2016	OF 12- 31- 2017	(B+C+D+E) /2	GENER ATION	TRANSM ISSION	DISTRIB UTION	GENER ATION	TRANSM ISSION	DISTRIB UTION	GENER ATION	TRANSM ISSION	DISTRIB UTION
1	ACCOUNT 190:														
2.01		0	0			0	0	0	0						
2.02		0	0			0	0	0	0						
2.03		0	0			0	0	0	0						
2.04		0	0			0	0	0	0						
2.05		0	0			0	0	0	0						
2.06		0	0			0	0	0	0						
2.07		0	0			0	0	0	0						
2.08		0	0			0	0	0	0						
2.09		0	0			0	0	0	0						
2.10		0	0			0	0	0	0						
2.11		0	0			0	0	0	0						
2.12		0	0			0	0	0	0						
2.13		0	0			0	0	0	0						
2.14		0	0			0	0	0	0						
2.15		0	0			0	0	0	0						
2.16		0	0			0	0	0	0						
2.17		0	0			0	0	0	0						
2.18		0	0			0	0	0	0						
2.19		0	0			0	0	0	0						

2.20							
2.21	0	0		0	0	0	0
2.22	0	0		0	0	0	0
2.23	0	0	1	0	0	0	0
2.24	0	0	1	0	0	0	0
2.25	0	0	1	0	0	0	0
2.26	0	0	1	0	0	0	0
2.27	0	0		0	0	0	0
2.28	0	0	1	0	0	0	0
2.29	0	0	1	0	0	0	0
2.30	0	0	1	0	0	0	0
2.31	0	0		0	0	0	0
2.32	0	0		0	0	0	0
2.33	0	0		0	0	0	0
2.34	0	0		0	0	0	0
2.35	0	0		0	0	0	0
2.36	0	0		0	0	0	0
2.37	0	0		0	0	0	0
2.38	0	0		0	0	0	0
2.39	0	0		0	0	0	0
2.40	0	0		0	0	0	0
2.41	0	0		0	0	0	0
2.42	0	0		0	0	0	0
2.43	0	0		0	0	0	0
2.44	0	0		0	0	0	0
2.45	0	0		0	0	0	0
2.46	0	0		0	0	0	0
2.47	0	0		0	0	0	0
2.48	0	0		0	0	0	0
2.49	0	0		0	0	0	0
2.50	0	0		0	0	0	0
2.51	0	0	1	0	0	0	0
2.52	0	0		0	0	0	0
2.53	0	0		0	0	0	0

254									
2.56 0	2.54	0	0			0	0	0	0
2.57 0	2.55	0	0			0	0	0	0
2.58 0	2.56	0	0			0	0	0	0
2.59 2.60 2.61 2.62 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0	2.57	0	0			0	0	0	0
260 0 0	2.58	0	0			0	0	0	0
261 0 0	2.59	0	0			0	0	0	0
262 0 0	2.60	0	0			0	0	0	0
2.63 0	2.61	0	0			0	0	0	0
2.64 0	2.62	0	0			0	0	0	0
2.65 0	2.63	0	0			0	0	0	0
2.66 0	2.64	0	0			0	0	0	0
2.67 0	2.65	0	0			0	0	0	0
2.68 0 0 0 0 0 0 2.69 0 0 0 0 0 0 2.70 0 0 0 0 0 0 2.71 0 0 0 0 0 0 0 2.72 0 0<	2.66	0	0			0	0	0	0
2.69 0 0 0 0 0 0 2.70 0 0 0 0 0 0 2.71 0 0 0 0 0 0 0 2.72 0	2.67	0	0			0	0	0	0
2.70 0	2.68	0	0			0	0	0	0
2.71 0 0 0 0 0 0 2.72 0 0 0 0 0 0 0 2.73 0	2.69	0	0			0	0	0	0
2.72 0	2.70	0	0			0	0	0	0
2.73 0	2.71	0	0			0	0	0	0
2.74 0	2.72	0	0			0	0	0	0
2.75 0	2.73	0	0			0	0	0	0
2.76 0	2.74	0	0			0	0	0	0
2.77 0	2.75	0	0			0	0	0	0
2.78 0 0 0 0 0 2.79 0 0 0 0 0 2.80 0 0 0 0 2.81 0 0 0 0 2.82 0 0 0 0 2.83 0 0 0 0 2.84 0 0 0 0	2.76	0	0			0	0	0	0
2.79 0 0 0 0 0 2.80 0 0 0 0 2.81 0 0 0 0 2.82 0 0 0 0 2.83 0 0 0 0 2.84 0 0 0	2.77	0	0			0	0	0	0
2.80 0 0 0 2.81 0 0 0 2.82 0 0 0 2.83 0 0 0 2.84 0 0 0	2.78	0	0			0	0	0	0
2.81 0 0 0 2.82 0 0 0 2.83 0 0 0 2.84 0 0 0	2.79	0	0			0	0	0	0
2.82 0 0 0 2.83 0 0 0 2.84 0 0 0	2.80			0	0	0			
2.83 0 0 0 2.84 0 0 0	2.81			0	0	0			
2.84 0 0 0	2.82			0	0	0			
	2.83			0	0	0			
2.85 0 0 0	2.84			0	0	0			
	2.85			0	0	0			

0

0

2.86

	4 ACCOUNT 190 - ARO-Related Deferals	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	3 TOTAL ACCOUNT 190	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2.	.91	0	0			0	0	0	0						
2.	2.90			0	0	0	0	0	0						
2.	2.89			0	0	0									
2.	2.88			0	0	0									
2.	2.87														

COMPANY NAME HERE Worksheet B-3 Excess/ Deficient ADIT Worksheet For Year Ended December 31, 20 Debit/(Credit) Α В С D Ε F G Н **TOTAL COMPANY BALANCES Excess Balance** Tax Rate Amortization at Methodology **Protected** Change Amortization Remeasurement Line No. Account (NOTE A) **Description of Account** Unprotected Act (NOTE C) (NOTE D) Period **Deferred Tax Account (NOTE** B) 1a 1b 1c 1d 1e 1f 1g 1h 1i 1j NOTE E **Regulatory Deferral Accounts** Regulatory Asset 2a 182.3 Regulatory Liability 254 2b 2c NOTE E

Total For Accounting Entries (Sum of Lines 1a through 2)

3

l 1/1/20 Beginning	J g Balances	К	L Balance She	M eet Entries	N Tax Expense Entries	0	P 12/31/20 Balance	Q Ending	R
Excess ADIT Regulatory Offset	Excess ADIT in Utility Deferrals	Balance Sheet Account Reclassific ations	182.3	254	410/411 Excess Amortization	410/411 Deferred Tax Expense/ (Benefit)	Excess ADIT Regulator y Offset Sum of	Excess ADIT in Utility Deferrals	Reference
							Cols (I) - (O)		
							1	ı	
]	
							_		
							-		
								1	
	_	-	_	_	_	_	_	_	

NOTE F

NOTE A: In order to ensure ratebase neutrality, AEP utilizes the fourth digit of its seven digit FERC Tax subaccount numbers to identify balances associated with utility operations vs regulatory reporting requirements. A "1" in the fourth digit of a FERC tax account refers to the utility operations balances or activity. Accounts with the "1" designation will be included in the determination of ratebase to be recovered in the formula rate. A "4" in the fourth position of the account number indicates accounts used to track regulatory accounting requirements. The excess ADIT amounts recorded in accounts with the "4" designation will be contra to the "1" balance, which will ensure that in the formula rate the excess or deficiency amounts will be part of ratebase, but at the total FERC account level the tax liability or asset will be recorded at the current Federal FIT rate. The amounts recorded in the "4" accounts will be offset on a net basis in the regulatory asset or liability subaccount established for this purpose.

NOTE B: The amount of the FIT gross up to recorded on regulatory assets and liabilities will be reported on the first line of ADIT accounts provided for each specific change in tax rates.

NOTE C: The amounts of the remeasurement shown here are as of the effective date of the change in tax rates and will remain static on this workpaper.

NOTE D: {REFERENCE OR CITE TO APPROVAL OF AMORTIZATION PERIOD FOR UNPROTECTED EXCESS OR DEFICIENT ADIT}

NOTE E: In the event of future tax rate changes, additional lines will be inserted in both the Total Company and Transmission Functional sections above as required to reflect any new ADIT or regulatory deferral accounts that may be necessary to track that tax rate change.

NOTE F: The amount of excess amortization entries shown in lines 1a through 1h are shown as a debit or credit to the ADIT account from which it is being amortized. The total in line 3 is the offset recorded to the 410/411 account and will tie to the total company amount of excess or deficient ADIT amortization shown on line 102 of the cost of service.

Cost of Service Formula Rate Using Actual/Projected FF1 Balances Worksheet C Supporting Working Capital Rate Base Adjustments TRANSMISSION COMPANY (B) (D) (F) (G) (A) (C) Materials & Supplies <u>Line</u> Number Balance (a) December Source 31, Balance @ December 31, Average Balance for Transmission Materials & Supplies General Materials & Supplies FF1, p. 227, ln 8, Col. (c) & (b) FF1, p. 227, ln 11, Col. (c) & (b) Stores Expense (Undistributed) – Account 163 FF1, p. 227, ln 16, Col. (c) & (b) Prepayment Balance Summary (Note 1) Transmission 100% Transmission **Total Included** Average of Excludable Transmission Plant Labor YE Balance Balances Related Related Related

	=	Prepayments Account 165 - Balance @ 12/31/							
		_	Excludable	100% Transmission	Transmission Plant	Transmission Labor	Total Included in Ratebase		
Acc. No.	Description	YE Balance	Balances	Related	Related	Related	(E)+(F)+(G)	Explanation	
			-		-		-		
			-		-		-		
			-			-	-		
			-				-		
			-			-	-		
			-				-		
			-				-		
						-	-		
			-				-		
	_		<u> </u>			-	-		
	Subtotal - Form 1, p 111.57.c	0	0	0	0	0	0		
		Prepayments Accou	ınt 165 - Balance @ 12/31/						

0

				Excludable	100% Transmission	Transmission Plant	Transmission Labor	Total Included in Ratebase	
20	Acc. No.	<u>Description</u>	YE Balance	Balances	Related	Related	Related	(E)+(F)+(G)	Explanation
21						0		-	
22						0		-	
23						0		-	
24								-	
25				0				-	
26				0				-	
27				0				-	
28				0				-	
29							0	-	
30				0				-	
31				0				-	
		Subtotal - Form 1, p 111.57.d							_

Prepayment Balance will not include: (i) federal and state income tax payments made to offset additional tax liabilities resulting (or expected to result) from prior federal or state audits or from the filing of one or more amended income tax returns; (ii) outstanding income tax refunds due to [company] resulting (or expected to result) from prior federal or state audits or from the filing of one or more amended income tax returns; or (iii) prepayments of federal or teteral or state adults or not me image of one or more amended income tax feturins, or (iii) prepayments or received state income taxes which are attributable to income earned during periods prior to January 1 of the year depicted in the Balance Sheet (as described in USofA Account 236).

Totals as of December 31, Totals as of December 31,

Average Balance

(H)

in Ratebase

(E)+(F)+(G)

(I)

Cost of Service Formula Rate Using Actual/Projected FF1 Balances

Worksheet D Supporting IPP Credits TRANSMISSION COMPANY

	AEPTRANSMISSION COMPANY	
<u>Line</u>	(A)	(B)
<u>Number</u>	Description	
1 2	Net Funds from IPP Customers 12/31/ (FORM 1, P269) Interest Expense (Company Records – Note 1)	-
3	Revenue Credits to Generators (Company Records – Note 1)	_
4	Other Adjustments	
5	Accounting Adjustment (Company Records – Note 1)	
6		-
7	Net Funds from IPP Customers 12/31/ (FORM 1, P269)	-
8	Average Balance for Year as Indicated in Column ((ln 1 + ln 7)/2) On this worksheet Company Records refers to AEP TRANSMISSION	-
Note 1	COMPANY 's general ledger.	

Cost of Service Formula Rate Using Actual/Projected FF1 Balances

Worksheet E Supporting Revenue Credits

AEP _____ TRANSMISSION COMPANY

		<u>(a)</u>	<u>(b)</u>	<u>(c)</u>
Line		<u>Total</u>	Non-	
Number	<u>Description</u>	<u>Company</u>	Transmission	<u>Transmission</u>
1	Account 450, Forfeited Discounts (FF1 p.300.16.(b); Company Records - Note 1)		-	
2	Account 451, Miscellaneous Service Revenues (FF1 p.300.17.(b); Company Records - Note 1)		-	
3	Account 454, Rent from Electric Property (FF1 p.300.19.(b); Company Records - Note 1)		-	
4	Account 4560015, Associated Business Development - (Company Records - Notes 1, 2)		-	
5	Account 456 - Other Electric Revenues - (Company Records - Notes 1, 2)		-	
5a	Account 457.1, Regional Control Service Revenues (FF1 p.300.23.(b); Company Records - Note 1)			
5b	Account 457.2, Miscellaneous Revenues (FF1p.300.24.(b); Company Records - Note 1)			
6	Subtotal - Other Operating Revenues (Company Total equals (FF1 p. 300.26.(b))		-	
7	Accounts 4470004 & 4470005, Revenues from Grandfathered Transmission Contracts - (Company Records - Note 1)		-	
8	Total Other Operating Revenues To Reduce Revenue Requirement			
9	Facility Credits under PJM OATT Section 30.9			-
Note 1	The total company data on this worksheet comes from the indicated FF1 source, or AEP TRANSMISSION COMPANY 's general ledger. The functional amounts identified as transmission revenue also come from the general ledger.			
Note 2	The total of line 4 and line 5 will equal total Account 456 as listed on FF1 p.300.21-22.(b)			

AEPTCo subsidiaries in PJM Cost of Service Formula Rate Using Actual/Projected FF1 Balances Worksheet F Supporting Allocation of Specific O&M or A&G Expenses AEP TRANSMISSION COMPANY

(A) (B) (C) (D) (E) 100% **(F)** <u>Line</u> Number 100% Transmission Item No. <u>Description</u> Regulatory O&M Deferrals & Amortizations Expense Non-Transmission Explanation Specific Total Detail of Account 561 Per FERC Form 1 FF1 p 321.85.b FF1 p 321.86.b FF1 p 321.87.b FF1 p 321.88.b FF1 p 321.89.b FF1 p 321.90.b FF1 p 321.91.b FF1 p 321.92.b 561.1 - Load Dispatch - Reliability
561.2 - Load Dispatch - Monitor & Operate Trans System
561.3 - Load Dispatch - Trans Service & Scheduling
561.4 - Scheduling, System Control & Dispatch
561.5 - Reliability, Planning and Standards Development
561.6 - Transmission Service Studies 10 11 561.7 - Generation Interconnection Studies 12 561.8 - Reliability, Planning and Standards Development Services 13 14 Total of Account 561 Account 928 15 16 17 18 19 20 21 Total (FERC Form 1 p.323.189.b) Account 930.1 22 23 24 25 26 27 28 29 30 31 32 33 34 35 36 37 38 Total (FERC Form 1 p.323.191.b) Account 930.2 39 40 41 42 43 Total (FERC Form 1 p.323.192.b)

Cost of Service Formula Rate Using Actual/Projected FF1 Balances

Worksheet G Supporting - Development of Composite State Income Tax Rate

		AEP	TRANSMISSION COMPANY	
1	Tax Rate			
	Apportionment Factor - Note 1			
	Effective State Tax Rate			
2	Tax Rate			
	Apportionment Factor - Note 1			
	Effective State Tax Rate			
3	Tax Rate			
	Apportionment Factor - Note 1			
	Effective State Tax Rate			
4	Tax Rate			
	Apportionment Factor - Note 1			
	Effective State Tax Rate			
5	Tax Rate			
	Apportionment Factor - Note 1			
	Effective State Tax Rate			
	Total Effective State Income Tax Rate	e		

Note 1 Apportionment Factors are determined as part of the Company's annual tax return for that jurisdiction.

AEPTCo subsidiaries in PJM Cost of Service Formula Rate Using Actual/Projected FF1 Balances Worksheet H Supporting Taxes Other than Income AEP ______ TRANSMISSION COMPANY (B) (C)

AEPTRANSMISSION COMPANY											
	(A)	(B)	(C)	(D)	(E)	(F)					
Line		Total									
No.	Account	Company	Property	Labor	Other	Non-Allocable					
1	Revenue Taxes	NOTE 1									
2	List Individual Taxes Here					-					
3	Real Estate and Personal Property Taxes										
4	Real and Personal Property - Jurisdiction #1		-								
5	Real and Personal Property - Jurisdiction #2		-								
6	Real and Personal Property - Jurisdiction #3		-								
7	Real and Personal Property - Other Jurisdictions		-								
8	Payroll Taxes										
9	Federal Insurance Contribution (FICA)			-							
10	Federal Unemployment Tax			-							
11	State Unemployment Insurance			-							
12	Line Deliberately Left Blank										
13	State Severance Taxes					_					
14	Miscellaneous Taxes										
15	List Individual Taxes Here					_					
16	Dist individual 1 dies fiere				=						
17						_					
18					_						
19					_						
20					_						
21						_					
22						_					
23	Total Taxes by Allocable Basis	-	-	-							
23	-										
23	(Total Company Amount Ties to FFI p.114, Ln 14,(c))										
23	-	is shown on WS H-1.									
23	(Total Company Amount Ties to FFI p.114, Ln 14,(c))	is shown on WS H-1.	erty Tax Allocation								
25	(Total Company Amount Ties to FFI p.114, Ln 14,(c))	is shown on WS H-1. Functional Proper Lines 24-58 Column (B)	erty Tax Allocation	Lines 24-58 Column (D)							
	(Total Company Amount Ties to FFI p.114, Ln 14,(e)) NOTE 1: The detail of each total company number and its source in the FERC Form 1	is shown on WS H-1.			General	<u>Total</u>					
23	(Total Company Amount Ties to FFI p.114, Ln 14,(c)) NOTE 1: The detail of each total company number and its source in the FERC Form 1 Functionalized Net Plant (TCOS, Lns 33 thru 36)	is shown on WS H-1. Functional Proper Lines 24-58 Column (B)	erty Tax Allocation	Lines 24-58 Column (D)	General	Total					
24	(Total Company Amount Ties to FFI p.114, Ln 14,(c)) NOTE 1: The detail of each total company number and its source in the FERC Form 1 Functionalized Net Plant (TCOS, Lns 33 thru 36) JURISDICTION	is shown on WS H-1. Functional Proper Lines 24-58 Column (B)	erty Tax Allocation	Lines 24-58 Column (D)	General	Total					
24 25	(Total Company Amount Ties to FFI p.114, Ln 14,(c)) NOTE 1: The detail of each total company number and its source in the FERC Form 1 Functionalized Net Plant (TCOS, Lns 33 thru 36) JURISDICTION Percentage of Plant in JURISDICTION	is shown on WS H-1. Functional Proper Lines 24-58 Column (B)	erty Tax Allocation	Lines 24-58 Column (D)	General	Total					
24 25 26	(Total Company Amount Ties to FFI p.114, Ln 14,(c)) NOTE 1: The detail of each total company number and its source in the FERC Form 1 Functionalized Net Plant (TCOS, Lns 33 thru 36)	is shown on WS H-1. Functional Proper Lines 24-58 Column (B)	erty Tax Allocation	Lines 24-58 Column (D)	General	Total					
24 25 26 27	(Total Company Amount Ties to FFI p.114, Ln 14,(e)) NOTE 1: The detail of each total company number and its source in the FERC Form 1 Functionalized Net Plant (TCOS, Lns 33 thru 36) JURISDICTION Percentage of Plant in JURISDICTION Net Plant in JURISDICTION (Ln 24 * Ln 25) Less: Net Value of Exempted Generation Plant	is shown on WS H-1. Functional Proper Lines 24-58 Column (B)	erty Tax Allocation	Lines 24-58 Column (D)	General	<u>Total</u>					
24 25 26 27 28	(Total Company Amount Ties to FFI p.114, Ln 14,(c)) NOTE 1: The detail of each total company number and its source in the FERC Form 1 Functionalized Net Plant (TCOS, Lns 33 thru 36)	is shown on WS H-1. Functional Proper Lines 24-58 Column (B)	erty Tax Allocation	Lines 24-58 Column (D)	General	Total					
24 25 26 27 28 29	(Total Company Amount Ties to FFI p.114, Ln 14,(c)) NOTE 1: The detail of each total company number and its source in the FERC Form 1 Functionalized Net Plant (TCOS, Lns 33 thru 36)	is shown on WS H-1. Functional Proper Lines 24-58 Column (B)	erty Tax Allocation	Lines 24-58 Column (D)	General	Total					
24 25 26 27 28	(Total Company Amount Ties to FFI p.114, Ln 14,(e)) NOTE 1: The detail of each total company number and its source in the FERC Form 1 Functionalized Net Plant (TCOS, Lns 33 thru 36) JURISDICTION Percentage of Plant in JURISDICTION Net Plant in JURISDICTION (Ln 24 * Ln 25) Less: Net Value of Exempted Generation Plant Taxable Property Basis (Ln 26 - Ln 27) Relative Valuation Factor Weighted Net Plant (Ln 28 * Ln 29)	is shown on WS H-1. Functional Proper Lines 24-58 Column (B)	erty Tax Allocation	Lines 24-58 Column (D)	General	<u>Total</u>					
24 25 26 27 28 29	(Total Company Amount Ties to FFI p.114, Ln 14,(c)) NOTE 1: The detail of each total company number and its source in the FERC Form 1 Functionalized Net Plant (TCOS, Lns 33 thru 36)	is shown on WS H-1. Functional Proper Lines 24-58 Column (B)	erty Tax Allocation	Lines 24-58 Column (D)	General	Total					
24 25 26 27 28 29 30	(Total Company Amount Ties to FFI p.114, Ln 14,(e)) NOTE 1: The detail of each total company number and its source in the FERC Form 1 Functionalized Net Plant (TCOS, Lns 33 thru 36) JURISDICTION Percentage of Plant in JURISDICTION Net Plant in JURISDICTION (Ln 24 * Ln 25) Less: Net Value of Exempted Generation Plant Taxable Property Basis (Ln 26 - Ln 27) Relative Valuation Factor Weighted Net Plant (Ln 28 * Ln 29)	is shown on WS H-1. Functional Proper Lines 24-58 Column (B)	erty Tax Allocation	Lines 24-58 Column (D)	General	Total					
24 25 26 27 28 29 30 31 32 33	(Total Company Amount Ties to FFI p.114, Ln 14,(e)) NOTE 1: The detail of each total company number and its source in the FERC Form 1 Functionalized Net Plant (TCOS, Lns 33 thru 36) JURISDICTION Percentage of Plant in JURISDICTION Net Plant in JURISDICTION (Ln 24 * Ln 25) Less: Net Value of Exempted Generation Plant Taxable Property Basis (Ln 26 - Ln 27) Relative Valuation Factor Weighted Net Plant (Ln 28 * Ln 29) General Plant Allocator (Ln 31 / (Total - General Plant)) Functionalized General Plant (Ln 31 * General Plant) Weighted JURISDICTION Plant (Ln 30 * 3.2)	is shown on WS H-1. Functional Proper Lines 24-58 Column (B)	erty Tax Allocation	Lines 24-58 Column (D)	General	<u>Total</u>					
24 25 26 27 28 29 30 31 32	(Total Company Amount Ties to FFI p.114, Ln 14,(c)) NOTE 1: The detail of each total company number and its source in the FERC Form 1 Functionalized Net Plant (TCOS, Lns 33 thru 36)	is shown on WS H-1. Functional Proper Lines 24-58 Column (B)	erty Tax Allocation	Lines 24-58 Column (D)	General	Total					
24 25 26 27 28 29 30 31 32 33	(Total Company Amount Ties to FFI p.114, Ln 14,(c)) NOTE 1: The detail of each total company number and its source in the FERC Form 1 Functionalized Net Plant (TCOS, Lns 33 thru 36)	is shown on WS H-1. Functional Proper Lines 24-58 Column (B)	erty Tax Allocation	Lines 24-58 Column (D)	General	Total					
24 25 26 27 28 29 30 31 32 33 34	(Total Company Amount Ties to FFI p.114, Ln 14,(c)) NOTE 1: The detail of each total company number and its source in the FERC Form 1 Functionalized Net Plant (TCOS, Lns 33 thru 36)	is shown on WS H-1. Functional Proper Lines 24-58 Column (B)	erty Tax Allocation	Lines 24-58 Column (D)	General	Total					
24 25 26 27 28 29 30 31 32 33 34 35	(Total Company Amount Ties to FFI p.114, Ln 14,(c)) NOTE 1: The detail of each total company number and its source in the FERC Form 1 Functionalized Net Plant (TCOS, Lns 33 thru 36) JURISDICTION Percentage of Plant in JURISDICTION (Ln 24 * Ln 25) Less: Net Value of Exempted Generation Plant Taxable Property Basis (Ln 26 - Ln 27) Relative Valuation Factor Weighted Net Plant (Ln 28 * Ln 29) General Plant Allocator (Ln 31 / (Total - General Plant)) Functionalized General Plant (Ln 31 * General Plant) Weighted JURISDICTION Plant (Ln 30 + 32) Functional Percentage (Ln 33/Total Ln 33) Net Plant in JURISDICTION (Ln 24 - Ln 26) Less: Net Value of Exempted Generation Plant	is shown on WS H-1. Functional Proper Lines 24-58 Column (B)	erty Tax Allocation	Lines 24-58 Column (D)	General	Total					
24 25 26 27 28 29 30 31 32 33 34 35 36 37	(Total Company Amount Ties to FFI p.114, Ln 14,(c)) NOTE 1: The detail of each total company number and its source in the FERC Form 1 Functionalized Net Plant (TCOS, Lns 33 thru 36)	is shown on WS H-1. Functional Proper Lines 24-58 Column (B)	erty Tax Allocation	Lines 24-58 Column (D)	General	<u>Total</u>					
24 25 26 27 28 29 30 31 32 33 34 35 36 37 38	(Total Company Amount Ties to FFI p.114, Ln 14,(c)) NOTE 1: The detail of each total company number and its source in the FERC Form 1 Functionalized Net Plant (TCOS, Lns 33 thru 36)	is shown on WS H-1. Functional Proper Lines 24-58 Column (B)	erty Tax Allocation	Lines 24-58 Column (D)	General	Total					
24 25 26 27 28 29 30 31 32 33 34 35 36 37 38	(Total Company Amount Ties to FFI p.114, Ln 14,(c)) NOTE 1: The detail of each total company number and its source in the FERC Form 1 Functionalized Net Plant (TCOS, Lns 33 thru 36) JURISDICTION Percentage of Plant in JURISDICTION (Ln 24 * Ln 25) Less: Net Value of Exempted Generation Plant Taxable Property Basis (Ln 26 - Ln 27) Relative Valuation Factor Weighted Net Plant (Ln 28 * Ln 29) General Plant Allocator (Ln 31 / (Total - General Plant)) Functionalized General Plant (Ln 31 * General Plant) Weighted JURISDICTION Plant (Ln 30 + 32) Functional Percentage (Ln 33/Total Ln 33) Net Plant in JURISDICTION (Ln 24 - Ln 26) Less: Net Value of Exempted Generation Plant Taxable Property Basis (Ln 36 - Ln 37) Relative Valuation Factor Weighted Net Plant (Ln 37 * Ln 38)	is shown on WS H-1. Functional Proper Lines 24-58 Column (B)	erty Tax Allocation	Lines 24-58 Column (D)	General	Total					
24 25 26 27 28 29 30 31 32 33 34 35 36 37 38 39 40	(Total Company Amount Ties to FFI p.114, Ln 14,(c)) NOTE 1: The detail of each total company number and its source in the FERC Form 1 Functionalized Net Plant (TCOS, Lns 33 thru 36)	is shown on WS H-1. Functional Proper Lines 24-58 Column (B)	erty Tax Allocation	Lines 24-58 Column (D)	General	Total					
24 25 26 27 28 29 30 31 32 33 34 35 36 37 38 39 40	(Total Company Amount Ties to FFI p.114, Ln 14,(c)) NOTE 1: The detail of each total company number and its source in the FERC Form 1 Functionalized Net Plant (TCOS, Lns 33 thru 36) JURISDICTION Percentage of Plant in JURISDICTION Net Plant in JURISDICTION (Ln 24 * Ln 25) Less: Net Value of Exempted Generation Plant Taxable Property Basis (Ln 26 - Ln 27) Relative Valuation Factor Weighted Net Plant (Ln 28 * Ln 29) General Plant Allocator (Ln 31 / (Total - General Plant)) Functionalized General Plant (Ln 31 * General Plant) Weighted JURISDICTION Plant (Ln 30 + 32) Functional Percentage (Ln 33/Total Ln 33) Net Plant in JURISDICTION (Ln 24 - Ln 26) Less: Net Value of Exempted Generation Plant Taxable Property Basis (Ln 36 - Ln 37) Relative Valuation Factor Weighted Net Plant (Ln 37 * Ln 38) General Plant Allocator (Ln 39 / (Total - General Plant)) Functionalized General Plant (Ln 41 * General Plant))	is shown on WS H-1. Functional Proper Lines 24-58 Column (B)	erty Tax Allocation	Lines 24-58 Column (D)	General	Total					
24 25 26 27 28 29 30 31 32 33 34 35 36 37 38 39 40	(Total Company Amount Ties to FFI p.114, Ln 14,(c)) NOTE 1: The detail of each total company number and its source in the FERC Form 1 Functionalized Net Plant (TCOS, Lns 33 thru 36)	is shown on WS H-1. Functional Proper Lines 24-58 Column (B)	erty Tax Allocation	Lines 24-58 Column (D)	General	Total					

AEPTCo subsidiaries in PJM Cost of Service Formula Rate Using Actual/Projected FF1 Balances Worksheet H page 2 Form 1 Source Reference of Company Amounts on WS H AEP______TRANSMISSION COMPANY

	(A)		(B)	(C)	(D)		
Line No.	Annual Tax Expenses by Type (Note 1)		Total Company	FERC FORM 1 Tie-Back	FERC FORM 1 Reference		
1 2	Revenue Taxes Gross Receipts Tax				P.263.1 ln 7 (i)		
3 4 5 6	"Real Estate and Personal Propety Tax Detail Annual Tax Expenses by Type (Note 1)" Real Estate and Personal Property Taxes Total (Ln 4 + Ln 5 + Ln 6 + Ln 7) Real and Personal Property - Real and Personal Property - Real and Personal Property - Real and Personal Property - Other Jurisdictions	(B) Tax Year	(C) Total Comapny	(D) FERC FORM 1 Tie-Back	P.263.2 ln 3 (i) P.263.2 ln 4 (i) (E) FERC FORM 1 Reference	(F) Tax Year Factor (Note 2)	(G) Transmission Function (Note 2)
					(D)		
Line No.	(A) Annual Tax Expense by Type (Note 1)			(C) FERC FORM 1 Tie-Back	(D) FERC FORM 1 Reference		
8 9	Payroll Taxes Federal Insurance Contribution (FICA)						
10	Federal Unemployment Tax				P.263 ln 6 (i)		
11	State Unemployment Insurance Line Left Deliberately Blank				P.263.1 ln 23 (i) P.263.3 ln 16 (i)		
13	State Severance Taxes						
14 15	Miscellaneous Taxes State Business & Occupation Tax				P.263 ln 21 (i)		
16	State Public Service Commission Fees				P.263 ln 22 (i) P.263 ln 26 (i)		
17	State Franchise Taxes				P.263.3 ln 20 (i) P.263.1 ln 18 (i) P.263.4 ln 27 (i)		
18	State Lic/Registration Fee				P.263.1 ln 15 (i) P.263.4 ln 21 (i)		

19	Misc. State and Local Tax	
20	Sales & Use	P.263.1 ln 12 (i)
20	Sales & Ose	P.263 ln 30 (i)
21	Federal Excise Tax	P.263.3 ln 21 (i)
21	receiai excise 1ax	P.263 ln 13 (i)
22	Maria di India di	P.263 ln 14 (i)
22	Michigan Single Business Tax	
23	Total Taxes by Allocable Basis	
	(Total Company Amount Ties to FFI p.114, Ln 14,(c))	

Note 1: The taxes assessed on each transmission company can differ from year to year and between transmission companies by both the type of taxes and the states in which they were assessed. Therefore, for each company, the types and jurisdictions of tax expense recorded on this page could differ from the same page in the same company's prior year template or from this page in other transmission companies' current year templates. For each update, this sheet will be revised to ensure that the total activity recorded hereon equals the total reported in account 408.1 on P. 114, Ln 14.(c) of the Ferc Form 1.

Note 2: The transmission functional amounts for any Real Estate and Property taxes listed on pages 263 of the FERC Form 1 will be allocated using the transmission functional allocator calculated for each state in Worksheet H of the applicable year that the taxes were assessed. Real and Personal Property - Other Jurisdictions will be allocated using the Gross Plant Allocator from the applicable year.

AEPTCo subsidiaries in PJM
Cost of Service Formula Rate Using Actual/Projected FF1
Balances
Worksheet I RESERVED
AEP ______TRANSMISSION COMPANY

RESERVED FOR FUTURE USE

AEPTCo subsidiaries in PJM

Regional Billi A. Determin	turn and Income Taxes ing. he 'R' with hypothetical centives (TCOS, ln 138)	basis point incr		•	11.49%								
	Incentive Adder												
	dditional basis point ince	entive											
	*		d atack and aquity m	aroanto ao io from the TCOS	lno 164 throug	h166)							
Determine K	(cost of long term debi			ercentage is from the TCOS	ilis 104 tilioug	(11100)							
	T T D1	<u>%</u>	Cost	Weighted cost	0.0000/								
	Long Term Debt	0.00%	0.00%		0.000%				,—				
	Preferred Stock	0.00%	0.00%		0.000%								
	Common Stock	0.00%	11.49%		0.000%				SU	MMARY OF PROJECTED A	ANNUAL RTEP RE	VENUE REQUII	
													Incentive
			R =		0.000%						Rev Require	W Incentives	Amounts
P. Dotoumin	o Dotum using 'D' with	hypothetical by	asis point POF ince	ease for Identified Project						PROJECTED YEAR			\$
	TCOS, ln 58)	nypotneticai ba	asis point KOE inci	ease for fuentified r roject					<u>. </u>	PROJECTED TEAR			
R (fom A. a					0.000%								
					0.00076								
Return (Rate													
		Return with hypo	othetical basis poin	t ROE increase for Identif	ied Projects.								
Return (from	,				-								
	x Rate (TCOS, ln 97)				0.00%								
Income Tax	Calculation (Return x	CIT)			-								
ITC Adjustm	nent				-								
Excess Defer	rred Income Tax				-								
Tax Affect o	of Permanent Differences				-								
Income Taxe	es				-								
II. Calculate Net	Plant Carrying Charge	e Rate (Fixed Cl	narge Rate or FCR	with hypothetical									
basis point RO				,									
	e Annual Revenue Req	uirement less re	turn and Income T	aves									
	enue Requirement (TCC		turn und meome 1	a.res.			_						
	ents (TCOS, Ln 80))B, III 1)											
Return (TC							-						
							-						
	es (TCOS, ln 108)		D . 1T			-							
	enue Requirement, Less			L.I. L.DOD			-						
	e Annual Revenue Req			oint increase in ROE.									
	nue Requirement, Less L	ease payments, R	leturn and Taxes				-						
	m I.B. above)						-						
	es (from I.C. above)												
	enue Requirement, with		increase				-						
	a & Amortization (TCOS												
Annual Rev.	. Req, w/ Basis Point RO	E increase, less I	Depreciation				-						
C D	ECD 141 4 4		or.										
	e FCR with hypothetic		OE increase.										
	ission Plant (TCOS, ln 3						-						
	enue Requirement, with		increase				-						
	Basis Point increase in RC						0.00%	,					
Annual Rev.	. Req, w / Basis Point Ro	DE increase, less	Dep.				-						
FCR with B	Basis Point ROE increase	, less Depreciatio	n				0.00%	,					
	epreciation (TCOS, ln 1						0.00%	<u></u>					
Incremental 1	FCR with Basis Point R	OE increase, less	Depreciation				0.00%	,					
П													
I. Calculation of	f Composite Depreciati	on Rate											
Average Trans	smission Plant Balance fo	or TCOS, ln	19				-						
Annual Deprec	ciation and Amortization	Expense(TCOS	, ln 83)				_						
Composite De	preciation Rate						0.00%	Note 1: Until AEP	TRANSM	ISSION COMPANY establis	hes Transmission pla	nt in service the	denreciation expens
Depreciable Li	ife for Composite Depre	ciation Rate					-	component of the carrying of		alculated as in the Operating (
Average Life is	in Whole Years						-	The calculation for AEP		NSMISSION COMPANY is			

TransCo Worksheet J - ATRR PROJECTED Calculation for PJM Projects Charged to Benefiting Zones

I

- V Determine the Revenue Requirement, and Additional
- . Revenue Requirement for facilities receiving incentives.

A. Base Plan Facilities

racinucs									
Facilities receiving ince	ntives accepted by	y FERC in Docket !	No.		(e.g. ER10-925-0	00)	Current Projected Year ARR		-
							Current Projected Year ARR w/ Incent	tive	_
Project Description							Current Projected Year Incentive ARI		
Project Description: Details							Current Projected Tear Incentive AKI		-
Investment		Current Year					CUMULATIVE HISTORY OF PRO		
Service Year (yyyy)		O ROE increase acce FCR w/o incentive		C (Basis Points)		-	CUMMULATIVE HISTORY OF PROJECTED ARR (WITH	ECTED ANNUAL REVENUE REQU & WITHOUT INCENTIVES) FRO!	
Service Month (1-12)		depreciation	s, iess			0.00%	YEAR	& WITHOUT INCENTIVES) FROM	VI EACH FRIOR
		FCR w incentives	approved for			0.00%			
Useful life		these facilities, les	s dep.			0.00%		AIN HISTORY OF PROJECTED AI	RRS OVER THE
aria ar							A HEL OF THE PROJECT		
CIAC (Yes or No)		O Annual Depreciation	on Expense	Ī		<u>.</u>	LIFE OF THE PROJECT. RTEP Projected	RTEP Projected Rev.	
					RTEP Rev.		Rev. Req't.From	Req't.From Prior Year	
Investment	Beginning	Depreciation	Ending	RTEP Rev. Req't.	Req't. with Incentives	Incentive Rev.	Prior Year Template	Template	
Year	Balance	Expense	Balance	w/o Incentives	**	Requirement ##	w/o Incentives	with Incentives **	
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57	-	1 -	-	-	ŀ	s -			
58 59		1:	I.	1:	ľ.	S - S -			
Droject Totals	-	1			ľ.	9 -			

Project Totals

** This is the total amount that needs to be reported to PJM for billing to all regions.

^{##} This is the calculation of additional incentive revenue on projects deemed by the FERC to be eligible for an incentive return. This additional incentive requirement is applicable for the life of this specific project. Each year the revenue requirement calculated for PJM

should be incremented by the amount of the incentive revenue calculated for that year on this project.

In order to calculate the proper monthly RTEP billing amount, PJM requires a 12 month revenue requirement for each RTEP project. As a result, notwithstanding the fact that the project was in service for a partial year, the project revenue requirement in the year that the project goes into service has been annualized (shown at the full-year level) so that PJM will collect the correct monthly billings.

AEPTCo subsidiaries in PJM Cost of Service Formula Rate Using Actual/Projected FF1 Balances Worksheet K Supporting Calculation of TRUE-UP PJM RTEP Project Revenue Requirement Billed to Benefiting Zones AEP TRANSMISSION COMPANY

Page 1 of 2

Calculate Return a A. Determine 'R'	and Income Taxes with hypothetical	with 0 basis point R I 0 basis point increas	OE increase for Proje se in ROE for Identific	cts Qualified for Region ed Projects	al Billing.						
	es (TCOS, ln 138	3)		11.49							
Project ROE Ince ROE with additio	ntive Adder nal 0 basis point in	centive		0		SUMMARY OF	TRUED-UP ANNUAL	REVENUE RE	QUIREMENTS FO	R RTEPPR	OJECTS
Determine R (co				ge is from the TCOS, lns	164 through 166)			Rev Require	W Incentives	Incen Amou	
Long Term Debt	0.00%	Cost 0.00%	Weighted cost 0.000%			TRUE-UP YEAR As Proje	t cted in Prior Year WS J			s	-
Preferred Stock	0.00%	0.00%	0.000%				Actual after True-up	<u> </u>	\$ -	\$	-
Common Stock	0.00%	0.00% R =	11.490% 0.000%			Т	rue-up of ARR For	-	-		-
B. Determine Ret Rate Base (TCO		h hypothetical 0 basis	s point ROE increase t	for Identified Projects.							
`			0.000								
R (fom A. above			%								
Return (Rate Base C. Determine Inc		Return with hypothe	tical 0 basis point ROI	E increase for Identified	Projects.						
Return (from B. Effective Tax Rat			0.00%								
Income Tax Calcu	ulation (Return x	CIT)	:								
Excess Deferred	d Income Tax ermanent Differe	nces	-								
hypothetical 0 basis point ROE ir A. Determine An	ncrease.	ge Rate (Fixed Charg quirement less return OS, ln 1)									
Lease Payments (Return (TCOS, 1	TCOS, Ln 80)			-							
Income Taxes (7				=							
Annual Revenue	Requirement, Less	Lease payments, Retu	ırn and Taxes	-							
B. Determine An	nual Revenue Req	uirement with hypot	hetical 0 basis point ir	ncrease in ROE.							
Annual Revenue I Return (from I.E		Lease payments, Retu	ırn and Taxes	-							
Income Taxes (fr Annual Revenue		0 Basis Point ROE in	crease	=							
Depreciation (TO Annual Rev. Req. increase, less Depre	, w/ 0 Basis Point F	ROE		Ē							
Net Transmission Annual Revenue	Plant (TCOS, In 3	0 Basis Point ROE inc		- - 0.00%							
FCR with 0 Basis FCR less Depreci	Point ROE increase ation (TCOS, In 19 with 0 Basis Point		p.	0.00% 0.00% 0.00%							
Calculation of Cor		ion Rate									
Average Transmiss	ion Plant Balance f	for TCOS, ln 19			-						
Annual Depreciatio Composite Deprecia		n Expense (TCOS, ln	83)		0.00%				ION COMPANY es		
Depreciable Life fo	r Composite Depre	eciation Rate			-	calculat	service the depreciation ed as in the Operating C	ompany formu	la approved in Dock	et No. ER08	3-1329.
Average Life in Wh	nole Years				-	calculat P.	ion for AEP	_1 KANSMIS	SION COMPANY IS	s snown on \	vorkshee

Determine the Revenue Requirement, and Additional Revenue Requirement for facilities receiving incentives. A. Base Plan Facilities IV.

Details

Facilities receiving incentives accepted by FERC in Docket No.	(e.g. ER10-925-000
Project Description:	

Investment Service Year (yyyy)	0		Current Year ROE increase accepted by FERC (Basis Points)									
Service Month (1-	·											
12)		FCR w/o incentives	es, less depreciation approved for these	n : facilities, less den			0.00%					
Useful life	-											
CIAC (Yes or No)	0	Annual Depreciat	ion Expense				-					
, ,												
Investment	Beginning	Depreciation	Ending	Average	RTEP Rev. Reg't.	RTEP Rev. Req't.	Incentive Rev.					
Year	Balance	Expense	Balance	Balance	w/o Incentives	with Incentives **	Requirement ##					
0	Balance -	Expense -	Balance -	Baiance -	Incentives -	Incentives ^^						
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Project Totals												

Prior Yr	Rev Require	W Incentives	Incentive Amounts
Projected	-	-	-
Prior Yr True-Up			-
True-Up Adjustment	_	_	

TRUE UP OF PROJECT REVENUE REQUIREMENT FOR PRIOR YEAR;
CUMULATIVE HISTORY OF TRUED-UP ANNUAL REVENUE REQUIREMENTS:
INPUT TRUE-UP ARR (WITH & WITHOUT INCENTIVES) FROM EACH PRIOR
YEAR

TEMPLATE BELOW TO MAINTAIN HISTORY OF TRUED-UP ARRS OVER THE

LIFE OF TH	IE PROJECT.			
RTEP		RTEP		
Projected Rev.		Projected Rev.		
Req't.From	RTEP Rev	Req't.From		
Req't.From		Req't.From		
Prior Year WS	Req't True-	Prior Year WS	RTEP Rev	True-up of
J	up	J	Req't True-up	Incentive
	w/o	with	with	with
w/o Incentives	Incentives	Incentives **	Incentives **	Incentives **
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^{**} This is the total amount that needs to be reported to PJM for billing to all regions.
This is the calculation of additional incentive revenue on projects deemed by the FERC to be eligible for an incentive return. This
additional incentive requirement is applicable for the life of this specific project. Each year the revenue requirement calculated for PJM
should be incremented by the amount of the incentive revenue calculated for that year on this project.

AEPTCo subsidiaries in PJM
Cost of Service Formula Rate Using Actual/Projected FF1 Balances
Worksheet L RESERVED
AEP ______ TRANSMISSION COMPANY RESERVED FOR FUTURE USE

AEPTCo subsidiaries in PJM

Cost of Service Formula Rate Using Actual/Projected FF1 Balances Worksheet M Supporting Calculation of Capital Structure and Weighted Average Cost of Capital

AEP WEST VIRGINIA TRANSMISSION COMPANY

		Average Balance of Common Equity									
Line No	Month	Proprietary Capital		Less Undistribut ed Sub Earnings (Acct 216.1)	Less AOCI (Acct	Average Balance of Common Equity (f)=(b)-(c)-					
	(a)	(b)	(c)	(d)	(e)	(d)-(e)					
	(Note A)	(FF1 112.16)	(FF1 250-251)	(FF1 112.12)	(FF1 112.15)						
1	December Prior to Rate Year			-	-	-					
2	January			-	-	-					
3	February			-	-	-					
4	March	-		-	-	-					
5	April			-	-	-					
6	May			-	-	-					
7	June			-	-	-					
8	July			-	-	-					
9	August			-	-	-					
10	September			-	-	-					
11	October			-	-	-					
12	November			-	-	-					
13	December of Rate Year			-	-	-					
14	Average of the 13 Monthly Balances			-	_	-					

			Average Balance of Long Term Debt							
							Gross			
				Acct 223	Acct 224		Proceeds			
			Less:	LT Advances	Senior	Less: Fair	Outstandin			
Line			Reacquired	from Assoc.	Unsecured	Value	g Long-			
No	Month	Bonds	Bonds	Companies	Notes	Hedges	Term Debt			

(a)	(b)	(c)	(d)	(e)	(f)	(g)=(b)-(c)+(d)+(e)- (f)
(Note A)	(FF1 112.18)	(FF1 112.19)	(FF1 112.20)		FF1, page 257, Col. (h) - Note 1	
15 December Prior to Rate Year	-	_	-		-	-
16 January	-	-	-		-	-
17 February	-	-	-		-	-
18 March	-	-	-		-	-
19 April	-	-	-		-	-
20 May	-	-	-		-	-
21 June	-	-	-		-	-
22 July	-	-	-		-	-
23 August	-	-	-		-	-
24 September	-	-	-		-	-
25 October	-	-	-		-	-
26 November	-	-	-		-	-
27 December of Rate Year	-	-	-		-	-
28 Average of the 13 Monthly Balances	-	-	-		-	-

NOTE 1: The balance of fair value hedges on outstanding long term debt are to be excluded from the balance of long term debt included in the formula's capital structure. (Page 257 Column H of the FF1)

Development of Cost of Long Term Debt Based on Average Outstanding Balance

	(a)	(b)	(c)	(d)	(e)	(f)	(g)
29	Annual Interest Expense for 2017						
20	Interest on Long Term Debt - Accts						
30	221 - 224 (256-257.33.i) Less: Total Hedge Gain/Expense Accu	ımulated		-			
	from p 256-257, col. (i) of FERC Form	n 1 included					
31	in Ln 30 and shown in 43 below.			-			
	Amort of Debt Discount & Expense -						
32	Acct 428 (117.63.c)			_			
	Amort of Loss on Reacquired Debt -						
33	Acct 428.1 (117.64.c)			_			
	Less: Amort of Premium on Debt -						
34	Acct 429 (117.65.c)			-			
35	Less: Amort of Gain on Reacquired						

	Debt - Acct 429.1 (117.66.c)				
36	Total Interest Expense (Ln 30 - 31 + 32 + 33 - 34 - 35)		-		
37	Average Cost of Debt for 2017 (Ln 36/ ln 28 (g))		[
	CALCULATION OF HEDGE GAI FROM TCOS	NS/LOSSES	TO BE EXCI	<u>LUDED</u>	
38	AEP WEST VIRGINIA TRANSM gains) related to interest hedging a		MPANY ma	y not include	costs (or
				Amortizati	on Period
		(Amortizati			
	HEDGE AMOUNTS BY	on of	Remaining		
	ISSUANCE (FROM p. 256-257 (i)			ъ.	Б. 11
20	of the FERC Form 1)	for 2017	d Balance	Beginning	Ending
39					
40					
41					
42					
	Net (Gain)/Loss Hedge				
43	Amortization To Be Removed	-			-
Dev	velopment of Cost of Preferred				
Sto	<u>ck</u>				
	Balance of Preferred Stock (Line 14				
44	` //		-		
	Dividends on Preferred Stock (Acct				
	437, FF1 118.29))				
	Average Cost of Preferred Stock (Ln 45 / ln 44)			_	

AEPTCo subsidiaries in PJM

Cost of Service Formula Rate Using Actual/Projected FF1 Balances
Worksheet N - Gains (Losses) on Sales of Plant Held For Future Use
AEP TRANSMISSION COMPANY

Note: Gain or loss on plant held for future are recorded in accounts 411.6 or 411.7 respectiviely. Sales will be
funtionalized based on the description of that asset. Sales of transmission assets will be direct assigned; sales of general
assets will be functionalized on labor. Sales of plant held for future use related to generation or distribution will not be
included in the formula.

(A)

(B)

inciude	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
Line	Date	Property Description	Function (T) or (G)	Basis	Proceeds	(Gain) / Loss	Functional Allocator	Functional Proceeds (Gain) /	FERC Account
			T = Transmission G = General					Loss	(Gain) / Loss
1						-	0.000%		
2						-	0.000%		
3						-	0.000%		
									-
4				Net (Gain) or Loss for				•

AEPTCo subsidiaries in PJM

Cost of Service Formula Rate Using Actual/Projected FF1 Balances Calculation of Post-employment Benefits Other than Pensions Expenses Allocable to Transmission Service

Worksheet O - PBOP Support
EP TRANSMISSION COMPANY

PBOP	(A)		(B)
1	Calculation of PBOP Expenses		
2	AEP System PBOP Rate		
3	Total AEP System PBOP expenses		
4	Base Year relating to retired personnel		
5	Amount allocated on Labor		
6	Total AEP System Direct Labor Expense		
	AEP System PBOP expense per dollar of	direct labor	
7	(PBOP Rate)		
8	Currently Approved PBOP Rate		(0.043)
9	Base PBOP TransCo labor expensed in co	arrent year	
10	Allowable TransCo PBOP Expense for co	arrent year (Ln 8 * Ln 9)	
11	Direct PBOP Expense per Actuarial Repo	ort	
12	Additional PBOP Ledger Entry (From Co	ompany Records)	
13	Medicare Credit		
14	PBOP Expenses From AEP Affiliates (Fr	om Company Records)	
15	Actual PBOP Expense	(Sum Lines 11-14)	
16	PBOP Adjustment	Line 10 less Line 15	

Note: PBOP Expense will be calculated in accordance with the settlement in Docket ER10-355.

As part of the annual update process, AEP will provide to transmission customers and include in its informational filing an independently prepared actuarial report that includes a ten (10) year forecast of PBOP expenses. During the annual update process conducted for rate year 2018 and every four years thereafter, Worksheet O will be used to determine whether the PBOP allowance rate (\$PBOP per \$Direct O&M Labor) should be adjusted going forward for the next four years. If the annual actuarial report issued during the year of any PBOP rate review projects PBOP costs during the next four years that, when allocated to the AEP Transmission Companies based on their projected direct labor expenses over that same projected four-year period, absent a change in the PBOP Rate, will likely cause the AEP East Transmission Companies to over or under collect their cumulative PBOP expenses by more than 20% of the projected next four year's total PBOP expense, taking into account the net over or under collection of such expenses during the previous four years, the PBOP rate shall be adjusted. In order to determine whether continued use of the then approved PBOP rate is likely to result in the AEP Companies' incurrence of a cumulative allowance of PBOP costs under the formula rate will result in a cumulative over or under-recoery of actual PBOP expenses exceeding 20% over the subsequent four year period, Worksheet O will be used to determine (a) the level of cumulative over or under collections of PBOP expense during the time since the PBOP allowance rate was last set, including carrying costs based on the weighted average cost of capital each year from the formula rate actual transmission cost-of-service (b) the cumulative net present value of projected PBOP costs during the next four years as estimated by the then current actuarial report, assuming a discount rate equal to the actual transmission cost of service average cost of capital for the immediately prior calendar year and (c) the cumulative net present value of continued collections over the next four years based on the projected AEP Transmission Companies direct labor expenses and the then effective PBOP allowance rate assuming a discount rate equal to the prior year weighted average cost of capital. If the absolute value of (a)+(b)-(c) exceeds 20% of (b), then the PBOP allowance rate used in the formula rate calculation shall be changed to the value that will cause the projected result of (a)+(b)-(c) to equal zero. If the projected over or under collection during the next four years, (a)+(b)-(c), is less than 20% of (b), then the PBOP Rate will continue in effect for the next four years at the then effective rate. If it is determined through this procedure AEP Companies will over-recover or under-recover actual PBOP expenses by more than 20% over the subsequent four-year period, AEP shall make a filing under FPA Section 205 to change the PBOP Rate stated in the formula rate shown on Worksheet O. No other changes to the formula rate may be included in that filing.

AEPTCo subsidiaries in PJM Worksheet - P

DEPRECIATION RATES

FOR TRANSMISSION PLANT PROPERTY ACCOUNTS EFFECTIVE AS OF 1/1/2020

AEP APPALACHIAN TRANSMISSION COMPANY

	PLANT	RATES
	ACCT.	Note 1
TRANSMISSION PLANT		
Energy Storage Equipment	351.0	14.22%
Structures & Improvements	352.0	1.99%
Station Equipment	353.0	2.70%
Towers & Fixtures	354.0	1.64%
Poles & Fixtures	355.0	3.46%
Overhead Conductor	356.0	1.65%
Underground Conduit	357.0	2.49%
Underground Conductors	358.0	4.72%
GENERAL PLANT		
Structures and Improvements	390	1.89%
Office Furniture and Equip.	391	3.21%
Transportation Equipment	392	3.46%
Stores Equipment	393	1.78%
Tools, Shop and Garage Equipment	394	2.59%
Laboratory Equipment	395	3.87%
Power Operated Equipment	396	3.90%
Communications Equipment	397	5.05%
Micellaneous Equipment	398	2.67%

Note: Per the Settlement in Docket No. ER10-355, Appendix A.1.2, AEP APPALACHIAN TRANSMISSION COMPANY shall use the depreciation rates shown above by FERC Account until such time as the FERC approves new depreciation rates pusuant to a Section 205 or 206 filing to change rates.

APCo Transco Depreciation Rates are based on the APCo VA Order in VA SCC Case No. PUR-2020-00015.

Composite Depreciation Rate	OpCo Company	OpCo Company	TOTAL
			

- 1 T-Plant (FF1 206.58.g)
- 2 T-Plant (FF1 206.58.b)
- 3 Average (Ln 1+ Ln 2)/2
- 4 Depreciation (FF1 336.7.f)
- 5 Composite Depreciation (Ln 3 / Ln 4)

Note: AEP APPALACHIAN TRANSMISSION COMPANY shall initially use the composite depreciation rate for Virginia and West Virginia shown above to estimate depreciation expense for transmission projects in Worksheets J and K until a composite depreciation rate based on transmission plant in service and depreciation expenses recorded by AEP APPALACHIAN TRANSMISSION COMPANY for its own transmission facilities can be calculated in AEP APPALACHIAN TRANSMISSION COMPANY's the first Annual Update including a True-Up TCOS.

AEPTCo subsidiaries in PJM Worksheet - P DEPRECIATION RATES FOR TRANSMISSION PLANT PROPERTY ACCOUNTS EFFECTIVE AS OF 3/11/2020

AEP INDIANA MICHIGAN TRANSMISSION COMPANY

TRANSMISSION PLANT	PLANT ACCT.	RATES Note 1
Land Rights	350.1	1.66%
Structures & Improvements	352.0	1.77%
Station Equipment	353.0	2.43%
Towers & Fixtures	354.0	2.57%
Poles & Fixtures	355.0	3.19%
Overhead Conductor	356.0	2.35%
Underground Conduit	357.0	2.30%
Underground Conductors	358.0	1.93%
GENERAL PLANT		
Structures and Improvements	390	2.08%
Office Furniture and Equip.	391	4.79%
Stores Equipment	393	7.35%
Tools, Shop and Garage Equipment	394	6.99%
Laboratory Equipment	395	5.41%
Power Operated Equipment	396	4.81%
Communications Equipment	397	3.91%
Micellaneous Equipment	398	3.32%

Note: Per the Settlement in Docket No. ER10-355, Appendix A.1.2, AEP INDIANA MICHIGAN TRANSMISSION COMPANY shall use the depreciation rates shown above by FERC Account until such time as the FERC approves new depreciation rates pusuant to a Section 205 or 206 filing to change rates.

Composite Depreciation Rate	OpCo Company	OpCo Company	<u>TOTAL</u>

T-Plant (FF1 206.58.g)

T-Plant (FF1 206.58.b)

Average (Ln 1+ Ln 2)/2

Depreciation (FF1 336.7.f)

Composite Depreciation (Ln 3 / Ln 4)

Note: Rates approved in Indiana Cause No. 45235 effective March 11, 2020.

AEPTCo subsidiaries in PJM Worksheet P DEPRECIATION RATES FOR TRANSMISSION PLANT PROPERTY ACCOUNTS EFFECTIVE AS OF 7/1/2015

AEP KENTUCKY TRANSMISSION COMPANY

	PLANT ACCT.	RATES Note 1
TRANSMISSION PLANT	-	
-Land Rights	350.1	1.44%
-Structures & Improvements	352.0	2.08%
-Station Equipment	353.0	2.15%
-Towers & Fixtures	354.0	2.61%
-Poles & Fixtures	355.0	3.95%
-Overhead Conductor	356.0	2.91%
-Underground Conduit	357.0	2.99%
-Underground Conductors	358.0	2.62%
GENERAL PLANT		
Land Rights	389.1	1.59%
Structures & Improvements	390	3.97%
Office Furniture & Equipment	391	3.20%
Transportation Equipment	392	3.52%
Stores Equipment	393	4.15%
Tools Shop & Garage Equipment	394	4.20%
Laboratory Equipment	395	5.76%
Power Operated Equipment	396	5.43%
Communication Equipment	397	5.66%
Miscellaneous Equipment	398	6.73%

Note: Per the Settlement in Docket No. ER10 355, Appendix A.1.2, AEP KENTUCKY TRANSMISSION COMPANY shall use the depreciation rates shown above by FERC Account until such time as the FERC approves new depreciation rates pusuant to a Section 205 or 206 filing to change rates.

	Composite Depreciation Rate	OpCo Company	OpCo Company	TOTAL
1	T-Plant (FF1 206.58.g)			
2	T-Plant (FF1 206.58.b)			
3	Average (Ln 1+ Ln 2)/2			
4	Depreciation (FF1 336.7.f)			
5	Composite Depreciation (Ln 3 / Ln 4)			

Note: AEP KENTUCKY TRANSMISSION COMPANY shall initially use the composite depreciation rate for KPCo shown above to estimate depreciation expense for transmission projects in Worksheets J and K until a composite depreciation rate based on transmission plant in service and depreciation expenses recorded by AEP KENTUCKY TRANSMISSION COMPANY for its own transmission facilities can be calculated in AEP KENTUCKY TRANSMISSION COMPANY's the first Annual Update including a True Up TCOS.

AEPTCo subsidiaries in PJM Worksheet - P DEPRECIATION RATES FOR TRANSMISSION PLANT PROPERTY ACCOUNTS EFFECTIVE AS OF 1/1/2020

AEP OHIO TRANSMISSION COMPANY

	PLANT ACCT.	RATES Note 1
TRANSMISSION PLANT		
Land Rights	350.1	1.03%
Energy Storage Equipment	351.0	14.22%
Structures & Improvements	352.0	1.95%
Station Equipment	353.0	2.43%
Towers & Fixtures	354.0	2.27%
Poles & Fixtures	355.0	3.53%
Overhead Conductor	356.0	2.30%
Underground Conduit	357.0	2.59%
Underground Conductors	358.0	3.09%
GENERAL PLANT		
Structures & Improvements	390.0	2.65%
Office Furniture & Equipment	391.0	3.73%
Stores Equipment	393.0	4.43%
Tools Shop & Garage Equipment	394.0	4.59%
Laboratory Equipment	395.0	5.01%
Power Operated Equipment	396.0	4.71%
Communication Equipment	397.0	4.87%
Miscellaneous Equipment	398.0	4.24%

Note: Per the Settlement in Docket No. ER10-355, Appendix A.1.2, AEP OHIO TRANSMISSION COMPANY shall use the depreciation rates shown above by FERC Account until such time as the FERC approves new depreciation rates pusuant to a Section 205 or 206 filing to change rates.

APCo Transco Depreciation Rates are based on the APCo VA Order in VA SCC Case No. PUR-2020-00015.

Composite Depreciation Rate	OpCo Company	OpCo Company	TOTAL
T-Plant (FF1 206.58.g)			
T-Plant (FF1 206.58.b)			
Average (Ln 1+ Ln 2)/2			
Depreciation (FF1 336.7.f)			
Composite Depreciation (Ln 3 / Ln 4)			

Note: AEP OHIO TRANSMISSION COMPANY shall initially use the composite depreciation rate for APCo, I&M and KPCo shown above to estimate depreciation expense for transmission projects in Worksheets J and K until a composite depreciation rate based on transmission plant in service and depreciation expenses recorded by AEP OHIO TRANSMISSION COMPANY for its own transmission facilities can be calculated in AEP OHIO TRANSMISSION COMPANY's the first Annual Update including a True-Up TCOS.

AEPTCo subsidiaries in PJM Worksheet - P DEPRECIATION RATES FOR TRANSMISSION PLANT PROPERTY ACCOUNTS EFFECTIVE AS OF 1/1/2020

AEP WEST VIRGINIA TRANSMISSION COMPANY

TRANSMISSION PLANT	PLANT ACCT.	RATES Note 1
Energy Storage Equipment	351.0	14.22 %
Structures & Improvements	352.0	1.99%
Station Equipment	353.0	2.70%
Towers & Fixtures	354.0	1.64%
Poles & Fixtures	355.0	3.46%
Overhead Conductor	356.0	1.65%
Underground Conduit	357.0	2.49%
Underground Conductors	358.0	4.72%
GENERAL PLANT		
Structures & Improvements	390.0	1.89%
Office Furniture & Equipment	391.0	3.21%
Transportation Equipment	392.0	3.46%
Stores Equipment	393.0	1.78%
Tools Shop & Garage Equipment	394.0	2.59%
Laboratory Equipment	395.0	3.87%
Power Operated Equipment	396.0	3.90%
Communication Equipment	397.0	5.05%
Miscellaneous Equipment	398.0	2.67%

Note: Per the Settlement in Docket No. ER10-355, Appendix A.1.2, AEP WEST VIRGINIA TRANSMISSION COMPANY shall use the depreciation rates shown above by FERC Account until such time as the FERC approves new depreciation rates pusuant to a Section 205 or 206 filing to change rates.

APCo Transco Depreciation Rates are based on the APCo VA Order in VA SCC Case No. PUR-2020-00015.

	Composite Depreciation Rate	OpCo Company	OpCo Company	<u>TOTAL</u>
1	T-Plant (FF1 206.58.g)			
2	T-Plant (FF1 206.58.b)			
3	Average (Ln 1+ Ln 2)/2			
4	Depreciation (FF1 336.7.f)			
5	Composite Depreciation (Ln 3 / Ln 4)			

Note: AEP WEST VIRGINIA TRANSMISSION COMPANY shall initially use the composite depreciation rate for APCo and WPCo shown above to estimate depreciation expense for transmission projects in Worksheets J and K until a composite depreciation rate based on transmission plant in service and depreciation expenses recorded by AEP WEST VIRGINIA TRANSMISSION COMPANY for its own transmission facilities can be calculated in AEP WEST VIRGINIA TRANSMISSION COMPANY's the first Annual Update including a True-Up TCOS.

AEP East Consolidated Utility Capital Structure Consolidation of Operating Companies' Capital Structure @ 12-31-Worksheet Q Page 1

1 E 2 L 3 L 4 S 5 L 6 T 7 F P Developm 8 In 12 L 13 L 13 L 14 L Developm	ent of Long Term Debt Balances at Year End onds (112.18.c&d) ess: Reacquired Bonds (112.19.c&d) T Advances from Assoc. Companies (112.20.c&d) enior Unsecured Notes (112.21.c&d) Excludes Spent Nuc Fuel Disp Fund ess: Fair Value Hedges (See Note on Ln 7 below) otal Long Term Debt Balance OTE: The balance of fair value hedges on outstanding long term debt are to F1) ent of Long Term Debt Interest Expense sterest on Long Term Debt (256-257.33.i) mort of Debt Discount & Expense (117.63.c) mort of Loss on Reacquired Debt (117.64.c) ess: Amort of Premium on Debt (117.65.c) ess: Amort of Gain on Reacquired Debt (117.66.c) ess: Hedge Interest on pp 256-257(i) TD Interest Expense ent of Cost of Preferred Stock and Preferred Dividends	Company be excluded from the	Company	Company erm debt include	Company ed in the formula	Company a's capital struct	Company ure. (page 257,	Structure Column H of the
1 E 2 L 3 L 4 S 5 L 6 T 7 F P Developm 8 In 12 L 13 L 13 L 14 L Developm	onds (112.18.c&d) ess: Reacquired Bonds (112.19.c&d) T Advances from Assoc. Companies (112.20.c&d) enior Unsecured Notes (112.21.c&d) Excludes Spent Nuc Fuel Disp Fund ess: Fair Value Hedges (See Note on Ln 7 below) fotal Long Term Debt Balance (OTE: The balance of fair value hedges on outstanding long term debt are to F1) ent of Long Term Debt Interest Expense tterest on Long Term Debt (256-257.33.i) mort of Debt Discount & Expense (117.63.c) mort of Loss on Reacquired Debt (117.64.c) ess: Amort of Gain on Reacquired Debt (117.66.c) ess: Hedge Interest on pp 256-257(i) TD Interest Expense	be excluded from the	e balance of long to	erm debt include	ed in the formula	ı's capital struct	ure. (page 257,	Column H of the
3 L 4 S 5 L 6 T 7 F Developm 8 In 10 A 11 L 12 L 13 L Developm	T Advances from Assoc. Companies (112.20.c&d) enior Unsecured Notes (112.21.c&d) Excludes Spent Nuc Fuel Disp Fund ess: Fair Value Hedges (See Note on Ln 7 below) total Long Term Debt Balance OTE: The balance of fair value hedges on outstanding long term debt are to F1) ent of Long Term Debt Interest Expense iterest on Long Term Debt (256-257.33.i) mort of Debt Discount & Expense (117.63.c) mort of Loss on Reacquired Debt (117.64.c) ess: Amort of Fremium on Debt (117.65.c) ess: Amort of Gain on Reacquired Debt (117.66.c) ess: Hedge Interest on pp 256-257(i) TD Interest Expense	be excluded from the	balance of long to	erm debt include	ed in the formula	ı's capital struct	ure. (page 257,	Column H of the
5 L 6 T N 7 F Developm 8 In 9 A 10 A 11 L 12 L 13 L 14 L Developm	ess: Fair Value Hedges (See Note on Ln 7 below) total Long Term Debt Balance (OTE: The balance of fair value hedges on outstanding long term debt are to F1) ent of Long Term Debt Interest Expense tterest on Long Term Debt (256-257.33.i) mort of Debt Discount & Expense (117.63.c) mort of Debt Discount & Expense (117.64.c) ess: Amort of Premium on Debt (117.65.c) ess: Amort of Gain on Reacquired Debt (117.66.c) ess: Hedge Interest on pp 256-257(i) TD Interest Expense	be excluded from the	balance of long to	erm debt includ	ed in the formula	ı's capital struct	ure. (page 257,	Column H of the
7 F Developm 8 In 9 A 11 L 12 L 13 L 14 L Developm	OTE: The balance of fair value hedges on outstanding long term debt are to F1) ent of Long Term Debt Interest Expense terest on Long Term Debt (256-257.33.i) mort of Debt Discount & Expense (117.63.c) mort of Loss on Reacquired Debt (117.64.c) ess: Amort of Premium on Debt (117.65.c) ess: Amort of Gain on Reacquired Debt (117.66.c) ess: Hedge Interest on pp 256-257(i) TD Interest Expense	be excluded from the	e balance of long to	erm debt includ	ed in the formula	a's capital struct	ure. (page 257,	Column H of the
Developm 8	ent of Long Term Debt Interest Expense tterest on Long Term Debt (256-257.33.i) mort of Debt Discount & Expense (117.63.c) mort of Loss on Reacquired Debt (117.64.c) ess: Amort of Premium on Debt (117.65.c) ess: Amort of Gain on Reacquired Debt (117.66.c) ess: Hedge Interest on pp 256-257(i) TD Interest Expense							
8 In 9 A 10 A 11 I I 12 I I 13 I I 14 I I Developm	tterest on Long Term Debt (256-257.33.i) mort of Debt Discount & Expense (117.63.c) mort of Loss on Reacquired Debt (117.64.c) ess: Amort of Premium on Debt (117.65.c) ess: Amort of Gain on Reacquired Debt (117.66.c) ess: Hedge Interest on pp 256-257(i) TD Interest Expense							
9 A 10 A 11 L 12 L 13 L 14 L Developm	mort of Debt Discount & Expense (117.63.c) mort of Loss on Reacquired Debt (117.64.c) ess: Amort of Prenium on Debt (117.65.c) ess: Amort of Gain on Reacquired Debt (117.66.c) ess: Hedge Interest on pp 256-257(i) TD Interest Expense							
11 L 12 L 13 L 14 L Developm	ess: Amort of Premium on Debt (117.65.c) ess: Amort of Gain on Reacquired Debt (117.66.c) ess: Hedge Interest on pp 256-257(i) TD Interest Expense							
12 L 13 L 14 L Developm	ess: Amort of Gain on Reacquired Debt (117.66.c) ess: Hedge Interest on pp 256-257(i) TD Interest Expense							
13 L 14 L Developm	ess: Hedge Interest on pp 256-257(i) TD Interest Expense							
14 L Developm	TD Interest Expense							
Developm								
	CHE OF COSE OF FECIEL OF STOCK AND FECIEFFED DIVIDENCE							
15 E	vividend Rate (p. 250-251. 7.a)							
	ar Value (p. 250-251. 8.c)							
	hares Outstanding (p.250-251. 8.e)							
18 N	fonetary Value (Ln 16 * Ln 17)							
19 E	tividend Amount (Ln 15 * Ln 18)							
	rividend Rate (p. 250-251. 7.a)							
	ar Value (p. 250-251. 8.c)							
	hares Outstanding (p.250-251. 8.e) fonetary Value (Ln 21 * Ln 22)							
	vividend Amount (Ln 20 * Ln 23)							
	rividend Rate (p. 250-251. 7.a)							
26 P	ar Value (p. 250-251. 8.c)							
	hares Outstanding (p.250-251. 8.e)							
	Ionetary Value (Ln 26 * Ln 27)							
	vividend Amount (Ln 25 * Ln 28)							
	rividend Rate (p. 250-251. 7.a) ar Value (p. 250-251. 8.c)							
	hares Outstanding (p.250-251. 8.e)							
	Innetary Value (Ln 31 * Ln 32)							
34 E	rividend Amount (Ln 30 * Ln 33)							
	referred Stock (Lns 18, 23, 28,33)							
	referred Dividends (Lns 19, 24, 29,34)							
	ent of Common Equity							
	roprietary Capital (112.16.c) ess: Preferred Stock (Ln 35 Above)							
	ess: Account 216.1 (112.12.c)							
	ess: Account 219.1 (112.15.c)							
	alance of Common Equity							
Calculation	on of Capital Shares							
	ong Term Debt (Ln 6 Above)							
	referred Stock (Ln 35 Above)							
	ommon Equity (Ln 41 Above) otal Company Structure							
	otal Company Structure TD Capital Shares (Ln 42 / Ln 45)							
	referred Stock Capital Shares (Ln 43 / Ln 45)							
	common Equity Capital Shares (Ln 44 / Ln 45)							
49 F	ESERVED							
	eserved							
	eserved							
	eserved on of Capital Cost Rate							
	TD Capital Cost Rate (Ln 14 / Ln 6)							
	referred Stock Capital Cost Rate (Ln 36 / Ln 35)							
55 C	ommon Equity Capital Cost Rate	11.49%	11.49%	11.49%	11.49%	11.49%	11.49%	11.49%
Calculation	on of Weighted Capital Cost Rate							
	TD Weighted Capital Cost Rate (Ln 46 * Ln 53)							
	referred Stock Capital Cost Rate (Ln 47 * Ln 54)							
	ommon Equity Capital Cost Rate (Ln 48 * Ln 55) otal Company Structure							

AEP East

AEP East Consolidated Utility Capital Structure Consolidation of Operating Companies' Capital Structure @ 12-31-____ Worksheet Q Page 2

		Worksh	eet Q Page 2						
									AEP East
									Operating
				To diam.		1/2			Companie
		Appalachi		Indiana Michigan	Kentucky	Kingspo rt Power	Ohio	Wheeling	s' Consolidat
		an Power		Power	Power		Power	Power	ed Capital
Line		Company		Company	Company	Compan	Company	Company	Structure
	opment of Long Term Debt Balances at Year End	Company		Company	Company	y	Company	Company	Structure
60	Bonds (112.18.c&d)								
61	Less: Reacquired Bonds (112.19.c&d)								
62	LT Advances from Assoc. Companies (112.20.c&d)								
	Senior Unsecured Notes (112.21.c&d) Excludes Spent Nuc Fuel Disp								
63	Fund								
64	Less: Fair Value Hedges (See Note on Ln 66 below)								
65	Total Long Term Debt Balance								
	NOTE: The balance of fair value hedges on outstanding long term debt ar	e to be excluded from	m the balance of	long term debt	included in the	formula's cap	ital structure. (p	. 257, Column I	of the FF1)
66				C			4	,	
	opment of Long Term Debt Interest Expense								
67	Interest on Long Term Debt (256-257.33.i)								
68	Amort of Debt Discount & Expense (117.63.c)								
69	Amort of Loss on Reacquired Debt (117.64.c)								
70	Less: Amort of Premium on Debt (117.65.c)								
71	Less: Amort of Gain on Reacquired Debt (117.66.c)								
72	Less: Hedge Interest on pp 256-257(i)								
73	LTD Interest Expense								
	opment of Cost of Preferred Stock and Preferred Dividends								
74	Dividend Rate (p. 250-251, 7.a)								
75 76	Par Value (p. 250-251. 8.c)								
76 77	Shares Outstanding (p.250-251. 8.e) Monetary Value (Ln 75 * Ln 76)								
78	Dividend Amount (Ln 74 * Ln 77)								
79	Dividend Rate (p. 250-251, 7.a)								
80	Par Value (p. 250-251. 7.a)								
81	Shares Outstanding (p.250-251. 8.e)								
82	Monetary Value (Ln 80 * Ln 81)								
83	Dividend Amount (Ln 79 * Ln 82)								
84	Dividend Rate (p. 250-251. 7.a)								
85	Par Value (p. 250-251. 8.c)								
86	Shares Outstanding (p.250-251. 8.e)								
87	Monetary Value (Ln 85 * Ln 86)								
88	Dividend Amount (Ln 84 * Ln 87)								
89	Dividend Rate (p. 250-251. 7.a)								
90	Par Value (p. 250-251. 8.c)								
91	Shares Outstanding (p.250-251. 8.e)								
92	Monetary Value (Ln 90 * Ln 91)								
93	Dividend Amount (Ln 89 * Ln 92)								
94	Preferred Stock (Lns 77, 82, 87,92)								
95	Preferred Dividends (Lns 78, 83, 88,93)								
	opment of Common Equity								
96									
97	,								
98 99									
100									
	lation of Capital Shares								
101									
102									
103									
104	1 2 \								
105									
106									
107									
108									
109									
110	RESERVED								
111									
	lation of Capital Cost Rate								
112									
113		44.4007	44.4007	44.400:	44.405		44.405	44.4007	44.40
114		11.49%	11.49%	11.49%	11.49%	11.49%	11.49%	11.49%	11.49%
	lation of Weighted Capital Cost Rate								
115	e i								
116 117									
118	1 7 1								
110	i otai Company Structure								

AEP East Consolidated Utility Capital Structure Consolidation of Operating Companies' Average Capital Structure Worksheet Q Page 3

		Worksheet Q P	age 3					
Line Develop	ment of Average Long Term Debt	Appalachi an Power Company	Indiana Michigan Power Company	Kentucky Power Company	Kingsport Power Company	Ohio Power Compan y	Wheeling Power Company	AEP East Operating Companies' Consolidated Capital Structure
119	Average Bonds (Ln 1 + Ln 60) / 2							
120	Less: Average Reacquired Bonds (Ln 2 + Ln 61) / 2							
	Average LT Advances from Assoc. Companies (Ln 3 + Ln 62) /							
121	2							
122	Average Senior Unsecured Notes (Ln 4 + Ln 63) / 2							
123	Less: Average Fair Value Hedges (See Note on Ln 125 below)							
124	Average Balance of Long Term Debt							77 0.1
	NOTE: The balance of fair value hedges on outstanding long term	debt are to be excluded from the	balance of long ten	m debt included	in the formula's	capital structu	ire. (p. 257, Co	umn H of the
125	FF1)							
Develop 126	ment of Long Term Debt Interest Expense Interest on Long Term Debt (256-257.33.i)							
120	Amort of Debt Discount & Expense (117.63.c)							
128	Amort of Loss on Reacquired Debt (117.64.c)							
129	Less: Amort of Premium on Debt (117.65.c)							
130	Less: Amort of Gain on Reacquired Debt (117.66.c)							
131	Less: Hedge Interest on pp 256-257(i)							
132	LTD Interest Expense							
Cost of	Preferred Stock and Preferred Dividends							
133	Average Balance of Preferred Stock (Ln 35 + Ln 94) / 2							
134	Preferred Dividends (Ln 36)							
	ment of Average Common Equity							
135	Average Proprietary Capital (Ln 37 + Ln 96) / 2							
136	Less: Average Preferred Stock (Ln 133 Above)							
137	Less: Average Account 216.1 (Ln 39 + Ln 98) / 2							
138	Less: Average Account 219.1 (Ln 40 + Ln 99) / 2							
139	Average Balance of Common Equity							
Calculat 140	Average Polaries of Long Town Dobt (Lon 124 Above)							
140	Average Balance of Long Term Debt (Ln 124 Above) Average Balance of Preferred Stock (Ln 133 Above)							
141	Average Balance of Common Equity (Ln 139 Above)							
143	Average of Total Company Structure							
143	Average Balance of LTD Capital Shares (Ln 140 / Ln 143)							
	Average Balance of Preferred Stock Capital Shares (Ln 141 / Ln							
145	143)							
	Average Balance of Common Equity Capital Shares (Ln 142/							
146	Ln 143)							
147	Reserved							
148	Reserved							
149	Reserved							
150	Reserved							
	tion of Capital Cost Rate							
151	LTD Capital Cost Rate (Ln 132 / Ln 124)							
152	Preferred Stock Capital Cost Rate (Ln 134 / Ln 133)	11.400/	11 4007	11.400/	11.4007	11.4007	11.4007	11.4007
153	Common Equity Capital Cost Rate	11.49%	11.49%	11.49%	11.49%	11.49%	11.49%	11.49%
Calculat 154	tion of Weighted Capital Cost Rate LTD Weighted Capital Cost Rate (Ln 144 * Ln 151)							
154	Preferred Stock Capital Cost Rate (Ln 144 * Ln 151)							
156	Common Equity Capital Cost Rate (Ln 146 * Ln 152)							
157	ACTUAL WEIGHTED AVG COST OF CAPITAL							
157								

AEPTCo subsidiaries in PJM Cost of Service Formula Rate Using Actual/Projected FF1 Balances Worksheet R – True-up With Interest (Hypothetical Example)

Reconciliation Revenue Requirement For Year 2018 Available May 25, 2019 2018 Revenue Requirement Forecast by October 31, 2017 True-up Adjustment -Over (Under) Recovery

Over (Under) Recovery Plus Interest Rate on Amount of Refunds or Surcharges (Note 1)

Over (Under) Average Monthly Interest Rate Monthly Interest Rate on Amount of Refunds or Surcharges (Note 1)

Over (Under) Average Monthly Interest Rate Monthly Interest Rate on Amount of Refunds or Surcharges (Note 1)

An over or under collection will be recovered prorata over 2018, held for 2019 and returned prorata over 2020

Calculation of Interest					Monthly	
_	Year	-		-	•	-
January	2018		0.2780%	12		
F 1	Year	-	0.27000/	- 11	•	-
February	2018		0.2780% 12 0.2780% 11 0.2780% 10 0.2780% 9 0.2780% 8 0.2780% 7 0.2780% 6 0.2780% 5 0.2780% 5 0.2780% 3 0.2780% 2 0.2780% 1 Annual			
March	Year	-	0.27900/	10	•	-
March	2018		0.2780%	10		
April	Year 2018	-	0.27900/	0	-	-
Aprii	Year	-	0.2780%	9		
May	2018	-	0.2780%	۷ -	•	-
iviay	Year	_	0.278070	0		
June	2018	-	0.2780%	7	•	-
June	Year	-	0.270070	′ _		_
July	2018		0.2780%	6		
July	Year	-	0.270070	_	_	_
August	2018		0.2780%	5		
Tugust	Year	_	0.270070	_		_
September	2018		0.2780%	4		
F	Year	_		_	-	_
October	2018		0.2780%	3		
	Year	-		_	•	-
November	2018		0.2780%	2		
	Year	-		_	-	-
December	2018		0.2780%	1		
						-
	***				Annual	
I	Year 2019		0.27900/	10		
January through December	2019	-	0.2/80%	12	-	-
O (U.I.) D. DI	T					
Over (Under) Recovery Plu Over 12 Months		mortized and Recovered			Monthly	
	Year	-		-	-	-
January	2020		0.2780%			
	Year	-		-	-	-
February	2020		0.2780%			
	Year	-	0.0000/	-	-	-
March	2020		0.2780%			
	Year	-	0.27000/	-	-	-
April	2020		0.2/80%			
Max	Year 2020	-	0.2780%	-	-	-
May	Year	_	0.2/80%			
June	2020	-	0.2780%	-	-	-
Suite	2020		0.2/00/0			Page 68
						Page 68

	Year	-		-	-	-
July	2020		0.2780%			
	Year	-		-	-	-
August	2020		0.2780%			
	Year	-		-	-	-
September	2020		0.2780%			
	Year	-		-	-	-
October	2020		0.2780%			
	Year	-		-	-	-
November	2020		0.2780%			
	Year	-	0.0000	-	-	-
December	2020		0.2780%		_	
				-		
True-Up Adjustment with					-	
Interest						
Less Over (Under)					-	
Recovery						
Total Interest					-	
I Otal Illiciest						

Note 1: The interest rate to be applied to the over recovery or under recovery amounts will be determined using the average monthly FERC interest rate (as determined pursuant to 18 C.F.R. Section 35.19a) for the twenty (20) months from the beginning of the rate year being trued-up through August 31 of the following year.

ATTACHMENT H-20

Annual Transmission Rates – AEP Transmission Companies (AEPTCo)¹ In the AEP Zone

- 1. The annual transmission revenue requirement is equal to the results of the AEPTCo formula and its associated attachments shown in Attachment H-20B posted on the PJM Internet site ("Formula Rate") which reflects the facilities within PJM and the associated revenue requirements of AEPTCo. The rates determined pursuant to Attachment H-20B shall be implemented pursuant to the Formula Rate Implementation Protocols set forth in Attachment H-20A.
- 2. **Determination of monthly charges for AEP Zone:** On a monthly basis, revenue credits shall be calculated based on the sum of AEPTCo's share of revenues collected during the month from: (i) the PJM Border Rate under Schedule 7; (ii) Network Integration Transmission Service to Non-Zone Network Load under Attachment H-A; and (iii) Firm Point-To-Point Transmission Service where the Point of Delivery is internal to the AEP Zone. The sum of these revenue credits and potential charges will appear as an adjustment (reduction) to the gross monthly rate stated above on a Transmission Customer's bill in that month for service under this schedule.
- 3. The revenue requirement in (1) shall be effective until amended by AEPTCo or modified by the Commission.
- 4. In addition to the rate set forth in section (1) above, the Network Customer purchasing Network Integration transmission Service shall pay for transmission congestion charges, and any other applicable charges, in accordance with the provisions of this Tariff, and any amounts necessary to reimburse the Transmission Owners for any amounts payable to them as sales, excise, "btu," carbon, value-added, or similar taxes (other than taxes based upon or measured by net income) with respect to the amounts payable pursuant to the Tariff.

AEPTCo subsidiaries in PJM include AEP Appalachian Transmission Company, Inc., AEP Indiana Michigan Transmission Company, Inc., AEP Ohio Transmission Company, Inc., and AEP West Virginia Transmission Company, Inc.

ATTACHMENT H-20 A

THE AEP TRANSMISSION COMPANIES IN THE AEP ZONE FORMULA RATE IMPLEMENTATION PROTOCOLS

The formula rate template ("Template"), and these formula rate implementation protocols ("Protocols") together comprise the filed rate ("Formula Rate") of AEP Appalachian Transmission Company Inc., AEP Indiana Michigan Transmission Company Inc., AEP Ohio Transmission Company Inc., and AEP West Virginia Transmission Company Inc. (collectively "AEPTCo") for transmission revenue requirement determinations under the PJM Interconnection, LLC ("PJM") Open Access Transmission Tariff ("PJM Tariff"). AEPTCo shall follow the instructions specified in the Formula Rate to calculate annually its net annual transmission revenue requirement, as set forth at Attachment H-20B, page 1, line 4 of the Template ("Net Revenue Requirement"). The Net Revenue Requirement shall be determined for January 1 to December 31 of a given calendar year (the "Rate Year"). The Formula Rate shall become effective for recovery of AEPTCo's Net Revenue Requirement upon the effective date for incorporation into the PJM Tariff through a filing with the Federal Energy Regulatory Commission ("FERC" or "Commission") under Section 205 of the Federal Power Act ("FPA"), 16 U.S.C. § 824d.

Section 1. <u>Annual Projection</u>

a. No later than October 31 preceding a Rate Year, and each subsequent Rate Year,

AEPTCo shall determine its projected Net Revenue Requirement for the upcoming Rate

Year in accordance with the Formula Rate ("Annual Projection"). The Annual Projection

shall include the True-Up Adjustment described and defined in Section 2 below, if

applicable. AEPTCo shall cause an electronic version of the Annual Projection to be

posted in both a Portable Document Format ("PDF") and fully-functioning Excel file at a

publicly accessible location on PJM's internet website and OASIS. The date on which the posting occurs shall be that year's "Annual Projection Publication Date."

- b. The posting of the Annual Projection shall:
 - (i) Provide the Formula Rate calculations and all inputs thereto, as well as supporting documentation and workpapers for data that are used in the projected Net Revenue Requirement;
 - (ii) Include all inputs in sufficient detail to identify the components of AEPTCo's projected Net Revenue Requirement, explanations of the bases for the projections and input data, and sufficient detail and explanation to enable Interested Parties² to replicate the calculation of the projected Net Revenue Requirement;
 - (iii) With respect to any Accounting Changes (as that term is defined in Section 3.e.iii)
 - A. Identify any Accounting Changes including:
 - i. The initial implementation of an accounting standard or policy;
 - The initial implementation of accounting practices for unusual or unconventional items where FERC has not provided specific accounting direction;
 - iii. Correction of errors and prior period adjustments that impact the projected Net Revenue Requirement calculation;
 - iv. The implementation of new estimation methods or policies that change prior estimates; and

² As used in these Protocols, "Interested Parties" shall include but not be limited to: (i) any Eligible Customer under the PJM Tariff; (ii) any regulatory agency with rate jurisdiction over a public utility located within the PJM footprint; (iii) any consumer advocate authorized by state law to review and contest the rates for any such public utility; and (iv) any party with standing under FPA section 205 or section 206.

- v. Changes to income tax elections;
- B. Identify items included in the projected Net Revenue Requirement at an amount other than on a historic cost basis (e.g., fair value adjustments);
- C. Identify any reorganization or merger transaction during the previous year and explain the effect of the accounting for such transaction(s) on inputs to the projected Net Revenue Requirement; and
- Provide, for each item identified pursuant to Section 1.b.iii.A C of these
 Protocols, a narrative explanation of the individual impact of such changes
 on the projected Net Revenue Requirement.
- (iv) Include the following information related to affiliate cost allocation:
 - A. A detailed description of the methodologies used to allocate and directly assign costs between AEP and its affiliates by service category or function, including any changes to such cost allocation methodologies from the prior year, and the reasons for those changes; and
 - B. The magnitude of such costs that have been allocated or directly assigned between AEP and each affiliate by service category or function.
- c. If the date for making the posting of the Annual Projection should fall on a weekend or a holiday recognized by FERC, then the posting shall be made no later than the next business day.³ Within five (5) calendar days of the posting, PJM shall provide notice of such posting via the PJM Members Committee email subscription ("PJM Exploder List"). Interested Parties can subscribe to the PJM Exploder List on the PJM website.

³ For the purposes of these Protocols, if any deadline included in these Protocols should fall on a weekend or a holiday recognized by FERC, then the deadline shall be extended to no later than the next business day.

- d. Together with the posting of the Annual Projection, AEPTCo shall cause to be posted on the PJM internet website and OASIS, and distributed to the PJM Exploder List, the time, date, location, and remote-access information for a stakeholder meeting with Interested Parties in order for AEPTCo to explain its Annual Projection and to provide Interested Parties an opportunity to seek information and clarifications regarding the Annual Projection ("Annual Projection Meeting"). The Annual Projection Meeting shall be held no less than twenty (20) business days and no more than thirty (30) business days after the posting of the Annual Projection. Notice of the Annual Projection Meeting shall be provided via the PJM Exploder List no less than seven (7) calendar days prior to the meeting. AEPTCo will provide remote access to the Annual Projection Meeting in order to ease burdens (e.g. travel costs) to ensure all Interested Parties have the opportunity to participate.
- e. To the extent AEPTCo agrees to make changes in the Annual Projection for a given Rate Year, such revised Annual Projection shall be promptly posted at a publicly accessible location on PJM's internet website and OASIS, and e-mailed to the PJM Exploder List. Changes posted prior to November 30 preceding the Rate Year, or the next business day if November 30 is not a business day (or such later date as can be accommodated under PJM's billing practices), shall be reflected in the Annual Projection for the Rate Year; changes posted after that date will be reflected, as appropriate, in the True-Up Adjustment for the Rate Year.
- f. The Annual Projection, including the True-Up Adjustment, for each Rate Year shall be subject to review, challenge, true-up, and refunds or surcharges with interest, to the extent and in the manner provided in these Protocols.

Section 2. <u>True-Up Adjustment</u>

AEPTCo will calculate the amount of under- or over-collection of its actual Net Revenue Requirement during the preceding Rate Year ("True-Up Adjustment") after the FERC Form No. 1 data for that Rate Year has been filed with the Commission. The True-Up Adjustment shall be the sum of the True-Up Adjustment Over/Under Recovery as determined in Section 2(a) and the Interest on the True-Up Adjustment Over/Under Recovery as determined in Section 2(b):

a. AEPTCo's projected Net Revenue Requirement collected during the previous Rate Year⁴ will be compared to AEPTCo's actual Net Revenue Requirement for the previous Rate Year calculated in accordance with AEPTCo's Formula Rate and based upon (i)

AEPTCo's FERC Form No. 1 for that same Rate Year, (ii) any FERC orders specifically applicable to AEPTCo's calculation of its annual revenue requirement, (iii) the books and records of AEPTCo (which shall be maintained consistent with the FERC Uniform System of Accounts ("USofA")), (iv) FERC accounting policies and practices applicable to the calculation of annual revenue requirements under formula rates, and (v) any aspects of the PJM Tariff Governing Documents that apply to the calculation of annual

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⁴ If the initial use of this Formula Rate covers only part of a calendar year, the initial projected annual Net Revenue Requirement will be divided by 12 to calculate the monthly projected cost of service to be collected each month it is effective that first year. Similarly, the actual Net Revenue Requirement will be divided by 12 to calculate the actual monthly cost of service to be collected during those same months of that year. Similar calculations of projected Net Revenue Requirement and actual Net Revenue Requirement will be made for the months prior to the effective date of this Formula Rate using the previous formula rate in effect during those months. The actual Net Revenue Requirements computed under each of the two formula rate periods that initial Rate Year will be added together to obtain the total actual Net Revenue Requirement. The first True-up Adjustment will compare this total actual Net Revenue Requirement to the Net Revenue Requirement collected under the two formulas for that initial Rate Year.

- revenue requirements under individual transmission owner formula rates,⁵ to determine any over- or under-recovery ("True-Up Adjustment Over/Under Recovery").
- b. Interest on any True-Up Adjustment Over/Under Recovery shall be calculated for the thirty-six (36) months during which the over or under recovery in the revenue requirement remains outstanding (*i.e.*, from January 1 of the Rate Year being trued-up through December 31 of the year in which the True-Up Adjustment Over/Under recovery is credited or collected). The interest rate to be applied to the True-Up Adjustment Over/Under Recovery amounts will be determined using the average monthly FERC Interest Rate (as determined pursuant to 18 C.F.R. § 35.19a) for the twenty (20) months from the beginning of the Rate Year being trued-up through August 31 of the following year.

Section 3. <u>Annual Update</u>

- a. On or before May 25 following each Rate Year, AEPTCo shall calculate its actual Net Revenue Requirement and the True-Up Adjustment as described in Section 2 ("Annual Update") for such Rate Year and, together with such other information described in this Section 3, shall cause such Annual Update to be posted, in both a PDF and fully-functioning Excel format, at a publicly accessible location on PJM's internet website and OASIS. Within five (5) calendar days of such posting, PJM shall provide notice of such posting via the PJM Exploder List.
- b. If the date for making the Annual Update posting should fall on a weekend or a holiday recognized by the FERC, then the posting shall be due on the next business day.

⁵ PJM Tariff Governing Documents include the PJM Tariff, Bylaws, Criteria, and Membership Agreements.

- c. The date on which the posting occurs shall be that year's "Annual Update Publication

 Date."
- d. Together with the posting of the Annual Update, AEPTCo shall cause to be posted on the PJM website and OASIS the time, date, location, and remote-access information for a stakeholder meeting with Interested Parties in order for AEPTCo to explain its Annual Update and to provide Interested Parties an opportunity to seek information and clarifications regarding the Annual Update ("Annual Update Meeting"). Notice of the Annual Update Meeting shall be provided via the PJM Exploder List no less than seven (7) calendar days prior to the meeting. The Annual Update Meeting shall be held no less than twenty (20) business days and no more than thirty (30) business days after the Annual Update Publication Date. AEPTCo will provide remote access to the Annual Update Meeting in order to ease burdens (e.g. travel costs) to ensure all Interested Parties have the opportunity to participate.
- e. The Annual Update posting for the Rate Year:
 - (i) Shall provide, via the Formula Rate worksheets, sufficiently detailed supporting documentation for data (and all adjustments thereto or allocations thereof) used in the Formula Rate that are not stated in the FERC Form No. 1;⁶
 - (ii) Shall provide sufficient detail and sufficient explanation to enable Interested

 Parties to replicate the calculation of the Annual Update results from the FERC

⁶ It is the intent of the Formula Rate, including the supporting explanations and allocations described therein, that each input to the Formula Rate for purposes of determining the actual Net Revenue Requirement for a given Rate Year will be either taken directly from the FERC Form No. 1 or reconcilable to the FERC Form No. 1 by the application of clearly identified and supported information. If the referenced form is superseded, the successor form(s) shall be utilized and supplemented as necessary to provide equivalent information as that provided in the superseded form. If the referenced form is discontinued, equivalent information as that provided in the discontinued form shall be utilized.

Form No. 1 and verify that each input to the Template is consistent with the requirements of the Formula Rate;

(iii) Shall identify:

- A. Any change in accounting that affects inputs to the Template or the resulting charges billed under the Formula Rate ("Accounting Change"), including:
 - i. The initial implementation of an accounting standard or policy;
 - The initial implementation of accounting practices for unusual or unconventional items where FERC has not provided specific accounting direction;
 - iii. Correction of errors and prior period adjustments that impact theTrue-Up Adjustment calculation;
 - iv. The implementation of new estimation methods or policies that change prior estimates; and
 - v. Changes to income tax elections;
- B. Any items included in the Annual Update at an amount other than on a historic cost basis (e.g., fair value adjustments);
- C. Any reorganization or merger transaction during the previous year and an explanation of the effect of the accounting for such transaction(s) on inputs to the Annual Update;
- D. For each item identified pursuant to Sections 3.e.iii.A C of these
 Protocols, the individual impact (in narrative format) of such changes on the Annual Update.

- (iv) Shall be subject to review and challenge in accordance with the procedures set forth in Sections 4, 5, and 6 of these Protocols.
- (v) Shall be subject to review and challenge in accordance with the procedures set forth in these Protocols with respect to the prudence of any costs and expenditures included for recovery in the Annual Update; provided, however, that nothing in these Protocols is intended to modify the Commission's applicable precedent with respect to the burden of going forward or burden of proof under formula rates in such prudence challenges; and
- (vi) Shall not seek to modify the Formula Rate and shall not be subject to challenge by any Interested Party seeking to modify the Formula Rate (i.e., any modifications to the Formula Rate will require, as applicable, an FPA section 205 or section 206 filing or initiation of a section 206 investigation).
- f. The following Formula Rate inputs shall be stated values to be used in the Formula Rate until changed pursuant to an FPA section 205 or section 206 proceeding: (i) rate of return on common equity ("ROE"); (ii) the depreciation and/or amortization rates as set forth in Attachment 10 to the Formula Rate template, and (iii) Post-Employment benefits other than Pension ("PBOP") charges pursuant to Statement of Financial Accounting Standards No. 106, Employers' Accounting for Postretirement Benefits Other Than Pensions.
- g. Example Timelines for 2018 Annual Projection and 2019 Annual Update:

 On or before October 31, 2017, AEPTCo will determine the projected Net Revenue

 Requirement for the 2018 Rate Year. AEPTCo will post the Annual Projection for the

 2018 Rate Year in accordance with Section 1 above. On or before May 25, 2019,

AEPTCo will post its Annual Update, consisting of the actual Net Revenue Requirement and True-Up Adjustment for the 2018 Rate Year determined pursuant to Section 2 above. Such True-Up Adjustment will be reflected in the Annual Projection of the Net Revenue Requirement for the 2020 Rate Year posted on or before October 31, 2019.

Section 4. Annual Review Procedures

Each Annual Update and Annual Projection shall be subject to the following review procedures ("Annual Review Procedures"):

- a. Interested Parties shall have up to the later of two-hundred-ten (210) calendar days after the applicable Publication Date, or thirty (30) calendar days after the receipt of all responses to timely submitted information requests (unless such period is extended with the written consent of AEPTCo or by FERC order) ("Review Period"), to review the calculations and to notify AEPTCo in writing of any specific challenges to the Annual Update or Annual Projection ("Preliminary Challenge"), including challenges related to Accounting Changes. An Interested Party submitting a Preliminary Challenge must specify the inputs, supporting explanations, allocations, calculations, or other information to which it objects, and provide an appropriate explanation and documents to support its challenge. AEPTCo shall cause to be posted all Preliminary Challenges at a publicly accessible location on PJM's internet website and OASIS, and a link to the website will be e-mailed to the PJM Exploder List.
- b. In the event of a Preliminary Challenge, AEPTCo will appoint a senior representative to work with the Interested Party (or its representatives) toward a resolution of the dispute.

- c. AEPTCo shall respond in writing to a Preliminary Challenge within twenty (20) business days of receipt, and its response shall notify the challenging party of the extent to which AEPTCo agrees or disagrees with the challenge. If AEPTCo disagrees with the Preliminary Challenge, it will provide the Interested Party with an explanation supporting the challenged inputs, explanations, allocations, calculations, or other information. AEPTCo shall promptly cause to be posted its responses to all Preliminary Challenges at a publicly accessible location on PJM's internet website and OASIS, and a link to the website will be e-mailed to the PJM Exploder List. Notwithstanding the foregoing, Preliminary Challenges and responses to Preliminary Challenges that include material deemed by AEPTCo to be confidential information will not be publicly posted but will be made available to requesting parties pursuant to a confidentiality agreement to be executed by AEPTCo and the requesting party.
- d. AEPTCo shall respond to all Preliminary Challenges submitted during the Review Period by no later than thirty (30) calendar days after the end of the Review Period.
- e. Interested Parties shall have up to one-hundred-fifty (150) calendar days after each annual Publication Date (unless such period is extended with the written consent of AEPTCo or by FERC order) to serve reasonable information requests on AEPTCo ("Discovery Period").
- f. Information requests shall be limited to what is necessary to determine: (i) the extent, effect, or impact of an Accounting Change; (ii) whether the Annual Update or Annual Projection fails to include data properly recorded in accordance with the Protocols; (iii) the proper application of the Template and procedures in the Protocols; (iv) the accuracy of data and consistency with the Formula Rate of the charges shown in the Annual

Update or Annual Projection; (v) the prudence of the actual costs and expenditures, including procurement methods and cost control methodologies; (vi) the effect of any change to the underlying USofA or FERC Form No. 1; and (vii) any other information that may reasonably have substantive effect on the calculation of the charge pursuant to the Formula Rate. The information requests shall not otherwise be directed to ascertaining whether the Formula Rate is just and reasonable. Information requests shall not solicit information concerning costs or allocations where the costs or allocation methods have been determined to be appropriate by FERC in the context of prior AEPTCo Annual Updates, except that such information requests shall be permitted if they (i) seek to determine if there has been a change in circumstances, (ii) are in connection with corrections pursuant to Section 6 of these Protocols, or (iii) relate to costs or allocations that have not previously been challenged and adjudicated by FERC. AEPTCo shall make a good faith effort to respond to reasonable information requests pertaining to the Annual Update or Annual Projection within fifteen (15) business days of receipt of such requests. AEPTCo shall respond to all reasonable information requests no later than thirty (30) calendar days after the end of the Discovery Period. AEPTCo will cause to be posted on the PJM website and OASIS all information requests from Interested Parties and AEPTCo's response(s) to such requests, and a link to the website will be e-mailed to the PJM Exploder List. Notwithstanding the foregoing, information and document requests and responses to information and document requests that include material deemed by AEPTCo to be confidential information will not be publicly posted but will be made available to requesting parties pursuant to a confidentiality agreement to

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- be executed by AEPTCo and the requesting party. Voluminous materials will be made available at a physical AEP site.
- h. AEPTCo shall not claim that responses to information and document requests provided pursuant to these Protocols are subject to any settlement privilege in any subsequent FERC proceeding addressing AEPTCo's Annual Update or Annual Projection.
- i. To the extent AEPTCo and any Interested Party(ies) are unable to resolve disputes related to information requests submitted in accordance with these Annual Review Procedures, AEPTCo or the Interested Party may petition the FERC to appoint an Administrative Law Judge as a discovery master to resolve the discovery dispute(s) in accordance with these Protocols and consistent with the FERC's discovery rules.
- j. Preliminary Challenges or Formal Challenges (as described in Sections 4 and 5) related to Accounting Changes shall be treated in the same manner under these Protocols as other challenges to the Annual Update or Annual Projection. Failure to make a Preliminary Challenge with respect to an Accounting Change in an Annual Update or Annual Projection shall not act as a bar with respect to a Formal Challenge with respect to that Annual Update or Annual Projection provided that the Interested Party submitted a Preliminary Challenge with respect to one or more other issues. Nor shall such failure bar a subsequent Preliminary Challenge related to a subsequent Annual Update or Annual Projection to the extent such Accounting Change affects the subsequent Annual Update or Annual Projection.
- k. If a change made by AEPTCo to its accounting policies, practices, or procedures, or the application of the Formula Rate, is found by the FERC to be unjust, unreasonable, or unduly discriminatory or preferential, then the calculation of the charges to be assessed

during the Rate Year then under review, and the charges to be assessed during any subsequent Rate Years, including any True-up Adjustments, shall not include such change, but shall include any remedy that may be prescribed by FERC in the exercise of its discretion as of the effective date of such remedy, to ensure that the Formula Rate continues to operate in a manner that is just, reasonable, and not unduly discriminatory or preferential.

Section 5. Resolution of Challenges

- a. Interested Parties shall have up to two –hundred-seventy (270) days following the applicable Publication Date (unless such period is extended with the written consent of AEPTCo or by FERC order), to file a challenge with the FERC ("Formal Challenge"). Such Formal Challenge shall be submitted in the same docket as the AEPTCo informational filing and shall be served on AEPTCo by electronic service on the date of such filing in accordance with Section 385.2010(f)(3) of the Commission's regulations. Subject to any applicable confidentiality and Critical Energy Infrastructure Information restrictions, all information and correspondence produced by AEPTCo pursuant to these Protocols may be included in any Formal Challenge or other FERC proceeding relating to the Formula Rate.
- b. Formal Challenges are to be filed pursuant to these Protocols, rather than under rule 206, and shall:
 - (i) Clearly identify the action or inaction which is alleged to violate the Formula Rate Template or Protocols;
 - (ii) Explain how the action or inaction violates the filed rate Template or Protocols;

- (iii) Set forth the business, commercial, economic or other issues presented by the action or inaction as such relate to or affect the party filing the Formal Challenge, including
 - A. The extent or effect of an Accounting Change;
 - B. Whether the Annual Update or Annual Projection fails to include data properly recorded in accordance with these Protocols;
 - C. The proper application of the Template and procedures in these Protocols;
 - D. The accuracy of the data and consistency with the Formula Rate of the charges shown in the Annual Update or Annual Projection;
 - E. The prudence of actual costs and expenditures;
 - F. The effect of any change to the underlying Uniform System of Accounts or the FERC Form No. 1; or
 - G. Any other information that may reasonably have substantive effect on the calculation of the charge pursuant to the Template.
- (iv) Make a good faith effort to quantify the financial impact or burden (if any) created for the party filing the Formal Challenge as a result of the action or inaction;
- (v) State whether the issues presented are pending in an existing Commission proceeding or a proceeding in any other forum in which the filing party is a party, and if so, provide an explanation why timely resolution cannot be achieved in that forum;

- (vi) State the specific relief or remedy requested, including any request for stay or extension of time, and the basis for that relief;
- (vii) Include all documents that support the facts in the Formal Challenge in possession of, or otherwise attainable by, the filing party, including, but not limited to, contracts and affidavits; and
- (viii) State whether the filing party utilized the Preliminary Challenge procedures described in these Protocols to dispute the action or inaction raised by the Formal Challenge, and, if not, describe why not.
- c. Preliminary and Formal Challenges shall be limited to issues that may be necessary to determine: (i) the extent or effect of an Accounting Change; (ii) whether the Annual Update or Annual Projection fails to include data properly recorded in accordance with these Protocols; (iii) the proper application of the Formula Rate and procedures in these Protocols; (iv) the accuracy of data and consistency with the Formula Rate of the calculations shown in the Annual Update and Annual Projection; (v) the prudence of actual costs and expenditures; (vi) the effect of any change to the underlying Uniform System of Accounts or FERC Form No. 1; or (vii) any other information that may reasonably have substantive effect on the calculation of the charge pursuant to the formula.
- d. Failure to raise an issue in a Preliminary Challenge shall not bar an Interested Party
 from raising that issue in a Formal Challenge, provided the Interested Party submitted a
 Preliminary Challenge during the Review Period with respect to one or more other
 issues. Failure to pursue an issue through a Preliminary Challenge or to lodge a Formal
 Challenge regarding any issue as to a given Annual Update shall bar pursuit of such

issue with respect to that Annual Update, but shall not bar pursuit of such issue or the lodging of a Formal Challenge as to such issue as it relates to a subsequent Annual Update.

- e. Any response by AEPTCo to a Formal Challenge must be submitted to the FERC within thirty (30) calendar days of the date of the filing of the Formal Challenge, and shall be served on the filing party(ies) and the PJM Exploder List on the date of such filing.
- f. In any Formal Challenge proceeding concerning an Annual Update (including corrections), Annual Projection, or Accounting Change(s), AEPTCo shall demonstrate the justness and reasonableness of the rate resulting from its application of the Formula Rate by demonstrating that it has correctly applied the terms of the Formula Rate consistent with these Protocols and that it followed the applicable requirements and procedures in applying the Formula Rate. Nothing herein is intended to alter the burdens applied by FERC with respect to prudence challenges.
- g. Except as specifically provided herein, nothing herein shall be deemed to limit in any way the right of AEPTCo to file unilaterally, pursuant to section 205 of the FPA and the regulations thereunder, an application seeking changes to the Formula Rate or to any of the stated value inputs requiring a section 205 filing under these Protocols (including, but not limited to, ROE and depreciation and amortization rates), or the right of any other party or the Commission to seek such changes pursuant to section 206 of the FPA and the regulations thereunder.
- h. AEPTCo may, at its discretion and at a time of its choosing, make a limited filing pursuant to section 205 to modify stated values in the Formula Rate (i) for amortization and depreciation rates, (ii) to correct obvious errors or omissions in the Formula Rate

such as would result from changes to the FERC Form No. 1, or (iii) PBOP charges pursuant to Statement of Financial Accounting Standards No. 106, Employers' Accounting for Postretirement Benefits Other Than Pensions. The sole issue in any such limited section 205 proceeding shall be whether such proposed change(s) is just and reasonable, and it shall not address other aspects of the Formula Rate or impose upon AEPTCo any burden with respect to such other aspects of the Formula Rate.

Section 6. Changes to Annual Updates

If AEPTCo determines or concedes that corrections to the Annual Update are required, whether under Sections 4 or 5 of these Protocols, including but not limited to those requiring corrections to its FERC Form No. 1, or input data used for a Rate Year that would have affected the Annual Update for that Rate Year, such corrections shall be reflected as adjustments in the Annual Update for the next Rate Year, with interest calculated in accordance with the FERC Interest Rate (as determined pursuant to 18 C.F.R. § 35.19a). This reconciliation mechanism shall apply in lieu of mid-Rate Year adjustments.

AEPTCo subsidiaries in PJM Cost of Service Formula Rate Using Actual/Projected FF1 Balances Worksheet A Rate Base Company Name

			Gross Pla	ant In Servi	ce	
Line No	Month	Transmission	Transmission ARO	General	General ARO	Intangible
	(a)	(d)	(e)	(h)	(i)	(j)
				FF1,	FF1, page 207	FF1, page 205
		FF1, page 207	FF1, page 207	page 207 Col.(g) &	Col.(g) &	Col.(g) &
		Col.(g) & pg.	Col.(g) & pg.	pg. 206	pg. 206	pg. 204
		206 Col. (b),	206 Col. (b),	Col. (b),	Col. (b), ln	Col. (b), ln
	(Note A)	ln 58	ln 57	ln 99	98	5
1	December Prior to Rate Year					
2	January					
3	February					
4	March					
5	April					
6	May					
7	June					
8	July					
9	August					
10	September					
11	October					
12	November					
13	December of Rate Year					
	Average of the 13 Monthly					
14	Balances	-	-	-	-	-

			Accumula	ted Deprecia	tion	
Line No	Month	Transmission	Transmissio n ARO	General	General ARO	Intangible
	(a)	(d)	(e)	(h)	(i)	(j)
			Company Records		Company Records (Included	
		FF1, page	(Included in	FF1, page	in total in	FF1, page
		219, ln 25,	total in	219, ln 28,	Column	200, ln 21,
	(Note A)	Col. (b)	Column (d))	Col. (b)	(h))	Col. (b)
15	December Prior to Rate Year					
16	January					
17	February					
18	March					
19	April					
20	May					
21	June					
22	July					
23	August					

24	September						
25	October						
26	November						
27	December of Rate Year						
	Average of the 13 Monthly						
28	Balances	-	-	-	-	-	

Line No	Month (a)	OATT Ancillary Services (GSU) Plant In Service (b) Company Records (included in total in column (d) of	OATT Ancillary Services (GSU) Accumulate d Depreciation (c) Company Records (included in total in column (d) of accumulated	Excluded Plant - Plant In Service (d) Company Records (included in total in column (d) of line 14,	Excluded Plant - Accumula ted Depreciat ion (e) Company Records (included in total in column (d) of line 28, Accumulat ed
	(Note A)	gross plant above)	depreciation above)	Gross Pla nt, above)	Depreciati on, above)
29	December Prior to Rate Year				_
30	January				-
31	February				-
32	March				-
33	April				-
34	May				-
35	June				_
36	July				_
37	August				_
38	September				_
39	October				_
40	November				_
41 42	December of Rate Year Average of the 13 Monthly				-

Balances	-	-	-	-

Transmission Accumulated Depreciation net of GSU and other Excludeable Balances (Ln 28d - 42c - 42e) --

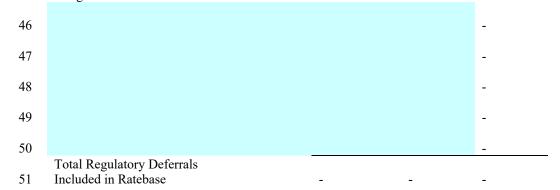
<u>Plant</u>	Held For Future Use	Source of Data	Balance @ December 31, 2017	<u>@</u> <u>December</u> 31, 2016	Average Balance for 2017
	(a)	(b)	(c)	(d)	(e)
		FF1, page			
		214, ln 47,			
44	Plant Held For Future Use	Col. (d)	-	-	-
	Transmission Plant Held	Company			
	For Future Use (Included	Records -			
45	in total on line 43)	Note 1	-	_	-

Regulatory Assets and Liabilities

Approved for Recovery In

Ratebase

Note: Regulatory Assets & Liabilities can only be included in ratebase pursuant to a 205 filing with the FERC.



<u>Unfunded Reserves Summary</u> (Company Records)

52	Description	Accoun	<u>ıt</u>			
53a					-	
53b					-	
54		Total	-	-	-	

NOTE 1: On this worksheet, "Company Records" refers to AEP's property accounting ledger.

NOTE 2: The ratebase should not include the

unamoritzed balance of hedging gains or losses.

AEPTCo subsidiaries in PJM Cost of Service Formula Rate Using Actual/Projected FF1 Balances

Worksheet B Supporting ADIT and ITC Balances

		AEPTRANSMISSION	COMPANY		
	(A)	(B)	(C)	(D)	(E)
Line			Balance @		
			<u>December</u>	Balance @ December	Average Balance
Number	<u>Description</u>	Source	<u>31,</u>	31,	for
1	Account 281				
2	Year End Utility Deferrals	FF1, p. 272 - 273, ln 8, Col. (k)			_
3	Less: ARO Related Deferrals	WS B-1 - Actual Stmt. AF Ln. 4 (Note 1)			- -
4	Less: Other Excluded Deferrals	WS B-1 - Actual Stmt. AF Ln. 3 (Note 1)			_
5	Transmission Related Deferrals	Ln 2 - ln 3 - ln 4	-	-	-
6	Account 282				
7	Year End Utility Deferrals	FF1, p. 274 - 275, ln 5, Col. (k)			_
8	Less: ARO Related Deferrals	WS B-1 - Actual Stmt. AF Ln. 7 (Note 1)			_
9	Less: Other Excluded Deferrals	WS B-1 - Actual Stmt. AF Ln. 6 (Note 1)			-
10	Transmission Related Deferrals	Ln 7 - ln 8 - ln 9	-	-	-
11	Account 283				
12	Year End Utility Deferrals	EEL = 276 277 l= 0 C=1 (b)			
13	Less: ARO Related Deferrals	FF1, p. 276 - 277, ln 9, Col. (k) WS B-1 - Actual Stmt. AF Ln. 13 (Note 1)			•
14	Less: Other Excluded Deferrals	WS B-1 - Actual Stmt. AF Ln. 13 (Note 1)			
15	Transmission Related Deferrals	Ln 12 - In 13 - In 14	-	-	
16					
16	Account 190	FF1 2041 0 G 1 ()			
17	Year End Utility Deferrals	FF1, p. 234, ln 8, Col. (c)			-
18	Less: ARO Related Deferrals	WS B-2 - Actual Stmt. AG Ln. 4 (Note 1)			-
19 20	Less: Other Excluded Deferrals Transmission Related Deferrals	WS B-2 - Actual Stmt. AG Ln. 3 (Note 1) Ln 17 - ln 18 - ln 19		_	
20	Transmission Related Defention	En 17 - In 10 - In 19			
21	Account 255				
22	Year End ITC Balances	FF1, p. 266-267, ln 8, Col. (h)			-
23	Less: Balances Not Qualified for Ratebase	Company Records - Note 1			_
24	ITC Balances Includeable in Ratebase	Ln 22 - ln 23	-		-
25	Transmission Related Deferrals	WS B-1 - Actual Stmt. AF Ln. 20 (Note 1)			-
Nome:	On this worksheet, "Company Records" refers to AEP's tax forecast and account proration required by IRS Letter Rule Section 1.167(I)-I(h)(6)(ii). Line item det	ing ledger. The PRTR will use projected ending balances and reflect ail of actual deferred tax items will be included on Worksheets B-1 and B-			
NOTE 1	2.				
NOTE 2	ADIT balances should exclude balances related to hedging activity.				

Company Name SPECIFIED DEFERRED CREDITS - Actual Cycle Only PERIOD ENDED DECEMBER 31, 2017

(DEBIT) CREDIT

	<u>COLUMN A</u>	COLUMN B	COLUMN C	COLUM N D	COLUM N E	COLUMN <u>F</u>	COLUM N G	COLUMN <u>H</u>	COLUMN <u>I</u>	COLUM N J	COLUMN <u>K</u>	COLUMN L	COLUM N M	COLUMN <u>N</u>	COLUMN O
	ACCUMULATED DEFERRED FIT ITEMS	PER BO BALANCE AS OF 12-31- 2016	DOKS BALANCE AS OF 12-31- 2017	APPLICA	BALANC E AS OF 12-31- 2017	AVERAGE ELECTRIC UTILITY (B+C+D+E)/2	FUNCTION GENER ATION	<u>TRANSMI</u> SSION	AVERAGE DISTRIB UTION	FUNCTION GENER ATION	ONALIZATION TRANSMI SSION	12/31/2016 <u>DISTRIB</u> <u>UTION</u>	FUNCTION GENER ATION	ONALIZATION TRANSMI SSION	12/31/2017 <u>DISTRIB</u> <u>UTION</u>
1.00	ACCOUNT 281:														
2.02		0	0			0	0	0	0						
2.04		0	0	0	0	0									
2.06		0	0	0	0	0									
3	TOTAL ACCOUNT 281 ACCOUNT 281 - ARO-Related	0	0	0	0	0	0	0	0	0	0	0	0	0	0
4	Deferrals	0	0	0	0	0	0	0	0	0	0	0	0	0	0
5	ACCOUNT 282:														
5.01		0	0			0	0	0	0						
5.02		0	0			0	0	0	0						
5.03 5.04		0	0			0	0	0	0						
5.05		0	0			0	0	0	0						
5.06		0	0			0	0	0	0						

5.07	0	0			0	0	0	0	
5.08	0	0			0	0	0	0	
5.09	0	0			0	0	0	0	
5.10	0	0			0	0	0	0	
5.11	0	0			0	0	0	0	
5.12	0	0			0	0	0	0	
5.13	0	0			0	0	0	0	
5.14	0	0			0	0	0	0	
5.15	0	0			0	0	0	0	
5.16	0	0			0	0	0	0	
5.17	0	0			0	0	0	0	
5.18	0	0			0	0	0	0	
5.19	0	0			0	0	0	0	
5.20	0	0			0	0	0	0	
5.21	0	0			0	0	0	0	
5.22	0	0			0	0	0	0	
5.23	0	0			0	0	0	0	
5.24	0	0			0	0	0	0	
.25	0	0			0	0	0	0	
5.26	0	0			0	0	0	0	
5.27	0	0			0	0	0	0	
5.28	0	0			0	0	0	0	
5.29	0	0			0	0	0	0	
5.30	0	0			0	0	0	0	
5.31	0	0			0	0	0	0	
5.32	0	0			0	0	0	0	
5.33	0	0			0	0	0	0	
5.34	0	0			0	0	0	0	
5.35	0	0			0	0	0	0	
5.36	0	0			0	0	0	0	
5.37	0	0			0	0	0	0	
5.38	0	0			0	0	0	0	
5.39			0	0	0				

5.40	0	0	0
5.41	0	0	0

6	TOTAL ACOUNT 282	0	0	0	0	0	0	0	0	0	0	0	0	0	0
7	ACCOUNT 282 - ARO-Related Deferals	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8	ACCOUNT 283:														
9.01		0	0			0	0	0	0						
9.02		0	0			0	0	0	0						
9.03		0	0			0	0	0	0						
9.04		0	0			0	0	0	0						
9.05		0	0			0	0	0	0						
9.06		0	0			0	0	0	0						
9.07		0	0			0	0	0	0						
9.08		0	0			0	0	0	0						
9.09		0	0			0	0	0	0						
9.10		0	0			0	0	0	0						
9.11		0	0			0	0	0	0						
9.12		0	0			0	0	0	0						
9.13		0	0			0	0	0	0						
9.14		0	0			0	0	0	0						
9.15		0	0			0	0	0	0						
9.16		0	0			0	0	0	0						
9.17		0	0			0	0	0	0						
9.18		0	0			0	0	0	0						
9.19		0	0			0	0	0	0						
9.20		0	0			0	0	0	0						
9.21		0	0			0	0	0	0						
9.22		0	0			0	0	0	0						
9.23		0	0			0	0	0	0						
9.24		0	0			0	0	0	0						

9.25	0	0	0	0	0	0
9.26	0	0	0	0	0	0
9.27	0	0	0	0	0	0
9.28	0	0	0	0	0	0
9.29	0	0	0	0	0	0
9.30	0	0	0	0	0	0
9.31	0	0	0	0	0	0
9.32	0	0	0	0	0	0
9.33	0	0	0	0	0	0
9.34	0	0	0	0	0	0
9.35	0	0	0	0	0	0
9.36	0	0	0	0	0	0
9.37	0	0	0	0	0	0
9.38	0	0	0	0	0	0
9.39	0	0	0	0	0	0
9.40	0	0	0	0	0	0
9.41	0	0	0	0	0	0
9.42	0	0	0	0	0	0
9.43	0	0	0	0	0	0
9.44	0	0	0	0	0	0
9.45	0	0	0	0	0	0
9.46	0	0	0	0	0	0
9.47	0	0	0	0	0	0
9.48	0	0	0	0	0	0
9.49	0	0	0	0	0	0
9.50	0	0	0	0	0	0
9.51	0	0	0	0	0	0
9.52	0	0	0	0	0	0
9.53	0	0	0	0	0	0
9.54	0	0	0	0	0	0
9.55	0	0	0	0	0	0
9.56	0	0	0	0	0	0
9.57	0	0	0	0	0	0

9.58							
9.60 9.61 9.61 9.62 9.63 9.63 9.64 9.65 9.65 9.65 9.66 9.67 9.68 9.69 9.69 9.69 9.69 9.69 9.70 9.70 9.71 9.73 9.73 9.74 9.74 9.74 9.74 9.74 9.75 9.75 9.75 9.75 9.76 9.76 9.77 9.76 9.77 9.78 9.79 9.70 9.70 9.70 9.70 9.70 9.70 9.70	9.58	0	0	0	0	0	0
9.61	9.59	0	0	0	0	0	0
9.62 9.63 9.64 9.65 9.66 9.66 9.67 9.68 9.69 9.69 9.70 9.71 9.72 9.72 9.73 9.74 9.75 9.75 9.76 9.77 9.78 9.78 9.79 9.79 9.79 9.79 9.79	9.60	0	0	0	0	0	0
9.63 9.64 9.65 9.66 9.66 9.67 9.68 9.69 9.69 9.69 9.70 9.71 9.72 9.73 9.74 9.75 9.75 9.76 9.76 9.77 9.78 9.78 9.79 9.79 9.79 9.79 9.70 9.70 9.70 9.71 9.72 9.73 9.74 9.75 9.75 9.76 9.76 9.76 9.70 9.77 9.78 9.78 9.78 9.79 9.78 9.70 9.70 9.70 9.70 9.70 9.70 9.70 9.70	9.61	0	0	0	0	0	0
9.64 0 0 0 0 0 0 9.65 0 0 0 0 0 0 9.66 0 0 0 0 0 0 9.67 0 0 0 0 0 0 9.68 0 0 0 0 0 0 0 9.69 0 <t< td=""><td>9.62</td><td>0</td><td>0</td><td>0</td><td>0</td><td>0</td><td>0</td></t<>	9.62	0	0	0	0	0	0
9.65 9.66 9.67 9.68 9.69 9.70 9.71 9.72 9.73 9.74 9.75 9.76 9.70 9.76 9.77 9.78 9.79 9.70 9.70 9.70 9.70 9.70 9.70 9.70	9.63	0	0	0	0	0	0
9.66 9.67 0 0 0 0 0 0 0 0 0 0 9.68 9.69 0 0 0 0 0 0 0 0 0 0 9.70 9.71 0 0 0 0 0 0 0 0 0 0 9.72 0 0 0 0 0 0 0 0 0 0 9.73 9.74 0 0 0 0 0 0 0 0 0 0 9.75 9.76 0 0 0 0 0 0 0 0 0 0 9.76 9.77 0 0 0 0 0 0 0 0 0 0 9.78 9.80 0 0 0 0 0 0 0 0 0 0 9.80 9.81 0 0 0 0 0 0 0 0 0 0 9.82 9.83 9.84 9.85 0 0 0 0 0 0 0 0 0 0 0 9.85 9.86 9.87 0 0 0 0 0 0 0 0 0 0 0 9.86 9.87 9.88 9 0 0 0 0 0 0 0 0 0 0 9.88 9.89 9.80 9.80 9.81 9.82 9.83 9.83 9.84 9.85 9.86 9.86 9.87 9.88 9.80 9.80 9.80 9.80 9.80 9.80 9.80	9.64	0	0	0	0	0	0
9.67 0 0 0 0 0 0 9.68 0 0 0 0 0 0 9.69 0 0 0 0 0 0 9.70 0 0 0 0 0 0 9.71 0 0 0 0 0 0 9.72 0 0 0 0 0 0 9.73 0 0 0 0 0 0 9.74 0 0 0 0 0 0 9.75 0 0 0 0 0 0 9.76 0 0 0 0 0 0 9.77 0 0 0 0 0 0 9.78 0 0 0 0 0 0 9.80 0 0 0 0 0 0 9.81 0 0 0 0 0 0 9.82 0 0 <td>9.65</td> <td>0</td> <td>0</td> <td>0</td> <td>0</td> <td>0</td> <td>0</td>	9.65	0	0	0	0	0	0
9.68 0 0 0 0 0 0 9.69 0 0 0 0 0 0 9.70 0 0 0 0 0 0 9.71 0 0 0 0 0 0 9.72 0 0 0 0 0 0 9.73 0 0 0 0 0 0 9.74 0 0 0 0 0 0 9.75 0 0 0 0 0 0 0 0 9.76 0	9.66	0	0	0	0	0	0
9.69 0	9.67	0	0	0	0	0	0
9.70 0 0 0 0 0 0 9.71 0 0 0 0 0 0 9.72 0 0 0 0 0 0 9.73 0 0 0 0 0 0 9.74 0 0 0 0 0 0 9.75 0 0 0 0 0 0 9.76 0 0 0 0 0 0 9.77 0 0 0 0 0 0 9.78 0 0 0 0 0 0 9.80 0 0 0 0 0 0 9.81 0 0 0 0 0 0 9.82 0 0 0 0 0 0 9.83 0 0 0 0 0 0 9.85 0 0 0 0 0 0 9.86 0 0 <td>9.68</td> <td>0</td> <td>0</td> <td>0</td> <td>0</td> <td>0</td> <td>0</td>	9.68	0	0	0	0	0	0
9.71 0 0 0 0 0 0 9.72 0 0 0 0 0 0 9.73 0 0 0 0 0 0 9.74 0 0 0 0 0 0 9.75 0 0 0 0 0 0 9.76 0 0 0 0 0 0 9.77 0 0 0 0 0 0 9.78 0 0 0 0 0 0 9.79 0 0 0 0 0 0 0 9.80 0 0 0 0 0 0 0 0 9.81 0 0 0 0 0 0 0 0 9.82 0 0 0 0 0 0 0 0 9.83 0 0 0 0 0 0 0 0 9.84 0	9.69	0	0	0	0	0	0
9.72 0 0 0 0 0 0 9.73 0 0 0 0 0 0 9.74 0 0 0 0 0 0 9.75 0 0 0 0 0 0 9.76 0 0 0 0 0 0 9.77 0 0 0 0 0 0 9.78 0 0 0 0 0 0 9.80 0 0 0 0 0 0 9.81 0 0 0 0 0 0 0 9.82 0 0 0 0 0 0 0 0 9.83 0 0 0 0 0 0 0 0 9.85 0 0 0 0 0 0 0 0 9.87 0 0 0 0 0 0 0 0 9.86 0	9.70	0	0	0	0	0	0
9.73 0 0 0 0 0 0 9.74 0 0 0 0 0 0 9.75 0 0 0 0 0 0 9.76 0 0 0 0 0 0 9.77 0 0 0 0 0 0 9.78 0 0 0 0 0 0 9.80 0 0 0 0 0 0 9.81 0 0 0 0 0 0 9.82 0 0 0 0 0 0 9.83 0 0 0 0 0 0 9.84 0 0 0 0 0 0 9.85 0 0 0 0 0 0 9.87 0 0 0 0 0 0 0 9.88 0 0 0 0 0 0 0 0	9.71	0	0	0	0	0	0
9.74 0 0 0 0 0 0 9.75 0 0 0 0 0 0 9.76 0 0 0 0 0 0 9.77 0 0 0 0 0 0 9.78 0 0 0 0 0 0 9.80 0 0 0 0 0 0 9.81 0 0 0 0 0 0 9.82 0 0 0 0 0 0 9.83 0 0 0 0 0 0 9.84 0 0 0 0 0 0 9.85 0 0 0 0 0 0 9.87 0 0 0 0 0 0 9.88 0 0 0 0 0 0 9.89 0 0 0 0 0 0	9.72	0	0	0	0	0	0
9.75 0 0 0 0 0 0 9.76 0 0 0 0 0 0 9.77 0 0 0 0 0 0 9.78 0 0 0 0 0 0 9.80 0 0 0 0 0 0 9.81 0 0 0 0 0 0 9.82 0 0 0 0 0 0 9.83 0 0 0 0 0 0 9.84 0 0 0 0 0 0 9.85 0 0 0 0 0 0 9.86 0 0 0 0 0 0 9.87 0 0 0 0 0 0 9.89 0 0 0 0 0 0 0	9.73	0	0	0	0	0	0
9.76 0 0 0 0 0 0 9.77 0 0 0 0 0 0 9.78 0 0 0 0 0 0 9.89 0 0 0 0 0 0 9.80 0 0 0 0 0 0 0 9.81 0 <t< td=""><td>9.74</td><td>0</td><td>0</td><td>0</td><td>0</td><td>0</td><td>0</td></t<>	9.74	0	0	0	0	0	0
9.77 0 0 0 0 0 0 9.78 0 0 0 0 0 0 9.79 0 0 0 0 0 0 9.80 0 0 0 0 0 0 9.81 0 0 0 0 0 0 0 9.82 0 0 0 0 0 0 0 0 9.83 0 0 0 0 0 0 0 0 9.84 0 0 0 0 0 0 0 0 9.85 0 0 0 0 0 0 0 0 9.87 0 0 0 0 0 0 0 0 9.89 0 0 0 0 0 0 0 0	9.75	0	0	0	0	0	0
9.78 0 0 0 0 0 0 9.79 0 0 0 0 0 0 9.80 0 0 0 0 0 0 9.81 0 0 0 0 0 0 9.82 0 0 0 0 0 0 9.83 0 0 0 0 0 0 9.84 0 0 0 0 0 0 9.85 0 0 0 0 0 0 9.87 0 0 0 0 0 0 9.88 0 0 0 0 0 0 0 9.89 0 0 0 0 0 0 0 0	9.76	0	0	0	0	0	0
9.79 0 0 0 0 0 0 9.80 0 0 0 0 0 0 9.81 0 0 0 0 0 0 9.82 0 0 0 0 0 0 9.83 0 0 0 0 0 0 9.84 0 0 0 0 0 0 9.85 0 0 0 0 0 0 9.86 0 0 0 0 0 0 9.87 0 0 0 0 0 0 9.88 0 0 0 0 0 0 0 9.89 0 0 0 0 0 0 0 0	9.77	0	0	0	0	0	0
9.80 0 0 0 0 0 0 9.81 0 0 0 0 0 0 9.82 0 0 0 0 0 0 9.83 0 0 0 0 0 0 9.84 0 0 0 0 0 0 9.85 0 0 0 0 0 0 9.86 0 0 0 0 0 0 9.87 0 0 0 0 0 0 9.88 0 0 0 0 0 0 0 9.89 0 0 0 0 0 0 0 0	9.78	0	0	0	0	0	0
9.81 0 0 0 0 0 0 9.82 0 0 0 0 0 0 9.83 0 0 0 0 0 0 9.84 0 0 0 0 0 0 9.85 0 0 0 0 0 0 9.86 0 0 0 0 0 0 9.87 0 0 0 0 0 0 9.88 0 0 0 0 0 0 9.89 0 0 0 0 0 0 0	9.79	0	0	0	0	0	0
9.82 0 0 0 0 0 0 9.83 0 0 0 0 0 0 9.84 0 0 0 0 0 0 9.85 0 0 0 0 0 0 9.86 0 0 0 0 0 0 9.87 0 0 0 0 0 0 9.88 0 0 0 0 0 0 9.89 0 0 0 0 0 0 0	9.80	0	0	0	0	0	0
9.82 0 0 0 0 0 0 9.83 0 0 0 0 0 0 9.84 0 0 0 0 0 0 9.85 0 0 0 0 0 0 9.86 0 0 0 0 0 0 9.87 0 0 0 0 0 0 9.88 0 0 0 0 0 0 9.89 0 0 0 0 0 0 0	9.81	0	0	0	0	0	0
9.83 0 0 0 0 0 0 9.84 0 0 0 0 0 0 9.85 0 0 0 0 0 0 9.86 0 0 0 0 0 0 9.87 0 0 0 0 0 0 9.88 0 0 0 0 0 0 9.89 0 0 0 0 0 0 0		0		0			0
9.84 0 0 0 0 0 0 9.85 0 0 0 0 0 0 9.86 0 0 0 0 0 0 9.87 0 0 0 0 0 0 9.88 0 0 0 0 0 0 9.89 0 0 0 0 0 0 0		0	0	0	0	0	0
9.85 0							
9.86 0							
9.87 0 0 0 0 0 9.88 0 0 0 0 0 0 9.89 0 0 0 0 0 0							
9.88 0 0 0 0 0 9.89 0 0 0 0 0 0							
9.89 0 0 0 0 0							
		0					

9.91		0	0			0	0	0	0						
9.92		0	0			0	0	0	0						
9.93		0	0			0	0	0	0						
9.94				0	0	0									
9.95				0	0	0									
9.96				0	0	0									
9.97				0	0	0									
9.98				0	0	0									
9.99				0	0	0									
10		0	0	0	0	0	0	0	0	0	0	0	0	0	0
11	DEFD STATE INCOME TAXES	0	0			0	0	0	0						
11.01				0	0	0									
12	TOTAL ACCOUNT 283	0	0	0	0	0	0	0	0	0	0	0	0	0	0
13	ACCOUNT 283 - ARO-Related Deferals	0	0	0	0	0	0	0	0	0	0	0	0	0	0
14	JURISDICTIONAL AMOUNTS FUNCTIONALIZED														
15	TOTAL COMPANY AMOUNTS FUNCTIONALIZED														
	PERIODE AND PAGE														
16	REFUNCTIONALIZED BASED ON JURISDICTIONAL PLANT														
	NOTE: POST 1970														
17	ACCUMULATED DEFERRED														
	INV TAX CRED. (JDITC)														
18	IN A/C 255														
18.01	IN A/C 255	0	0			0	0	0	0						
	IN A/C 255	0	0			0	0	0	0						
18.01	IN A/C 255														

Company Name ACCUMULATED DEFERRED INCOME TAX IN ACCOUNT 190 - Actual Cycle Only PERIOD ENDED DECEMBER 31, 2017

DEBIT (CREDIT)

	<u>COLUMN A</u>	COLUMN B	COLUMN C	COLUM N D	COLU MN E	COLUMN F	COLUM N G	COLUM N H	COLUM N I	COLUM N J	COLUM NK	COLUM N L	COLUI N M	COLUM N N	COLUM NO
		PER E	BOOKS	APPLICAB UTIL	BLE/NON-	AVERAGE ELECTRIC	FUNCTIO	NALIZATION	AVERAGE	FUNCTIO	NALIZATION	12/31/2016	FUNC	TONALIZATIO	N 12/31/2017
		BALANCE AS	BALANCE AS	BALAN CE AS	BALA NCE AS	UTILITY									
	ACCUMULATED DEFERRED FIT ITEMS	OF 12-31- 2016	OF 12-31- 2017	OF 12- 31-2016	OF 12- 31- 2017	(B+C+D+E) /2	GENER ATION	TRANSM ISSION	DISTRIB UTION	GENER ATION	TRANSM ISSION	DISTRIB UTION	GENE ATION		DISTRIB UTION
1	ACCOUNT 190:														
2.01		0	0			0	0	0	0						
2.02		0	0			0	0	0	0						
2.03		0	0			0	0	0	0						
2.04		0	0			0	0	0	0						
2.05		0	0			0	0	0	0						
2.06		0	0			0	0	0	0						
2.07		0	0			0	0	0	0						
2.08		0	0			0	0	0	0						
2.09		0	0			0	0	0	0						
2.10		0	0			0	0	0	0						
2.11		0	0			0	0	0	0						
2.12		0	0			0	0	0	0						
2.13		0	0			0	0	0	0						
2.14		0	0			0	0	0	0						
2.15		0	0			0	0	0	0						
2.16		0	0			0	0	0	0						
2.17		0	0			0	0	0	0						
2.18		0	0			0	0	0	0						
2.19		0	0			0	0	0	0						
2.20		0	0			0	0	0	0						

2.21						
2.22	0	0	0	0	0	0
2.23	0	0	0	0	0	0
2.24	0	0	0	0	0	0
2.25	0	0	0	0	0	0
2.26	0	0	0	0	0	0
2.27	0	0	0	0	0	0
2.28	0	0	0	0	0	0
2.29	0	0	0	0	0	0
2.30	0	0	0	0	0	0
2.31	0	0	0	0	0	0
2.32	0	0	0	0	0	0
2.33	0	0	0	0	0	0
2.34	0	0	0	0	0	0
2.35	0	0	0	0	0	0
2.36	0	0	0	0	0	0
2.37	0	0	0	0	0	0
2.38	0	0	0	0	0	0
2.39	0	0	0	0	0	0
2.40	0	0	0	0	0	0
2.41	0	0	0	0	0	0
2.42	0	0	0	0	0	0
2.43	0	0	0	0	0	0
2.44	0	0	0	0	0	0
2.45	0	0	0	0	0	0
2.46	0	0	0	0	0	0
2.47	0	0	0	0	0	0
2.48	0	0	0	0	0	0
2.49	0	0	0	0	0	0
2.50	0	0	0	0	0	0
2.51	0	0	0	0	0	0
2.52	0	0	0	0	0	0
2.53	0	0	0	0	0	0
2.54	0	0	0	0	0	0

2.55	0	0			0	0	0	0	
2.56	0	0			0	0	0	0	
2.57	0	0			0	0	0	0	
2.58	0	0			0	0	0	0	
2.59	0	0			0	0	0	0	
2.60	0	0			0	0	0	0	
2.61	0	0			0	0	0	0	
2.62	0	0			0	0	0	0	
2.63	0	0			0	0	0	0	
2.64	0	0			0	0	0	0	
2.65	0	0			0	0	0	0	
2.66	0	0			0	0	0	0	
2.67	0	0			0	0	0	0	
2.68	0	0			0	0	0	0	
2.69	0	0			0	0	0	0	
2.70	0	0			0	0	0	0	
2.71	0	0			0	0	0	0	
2.72	0	0			0	0	0	0	
2.73	0	0			0	0	0	0	
2.74	0	0			0	0	0	0	
2.75	0	0			0	0	0	0	
2.76	0	0			0	0	0	0	
2.77	0	0			0	0	0	0	
2.78	0	0			0	0	0	0	
2.79	0	0			0	0	0	0	
2.80			0	0	0				
2.81			0	0	0				
2.82			0	0	0				
2.83			0	0	0				
2.84			0	0	0				
2.85			0	0	0				
2.86			0	0	0				

0

0

2.87

4	ACCOUNT 190 - ARO-Related Deferals	0	0	0	0	0	0	0	0	0	0	0	0	0	0
3	TOTAL ACCOUNT 190	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2.91		0	0			0	0	0	0						
2.90				0	0	0	0	0	0						
2.89				0	0	0									
2.88															

COMPANY NAME HERE Worksheet B-3 Excess/ Deficient ADIT Worksheet For Year Ended December 31, 20_ Debit/(Credit) Ε G Α В С D F Н **TOTAL COMPANY BALANCES Excess Balance** Tax Rate Amortization at Change Remeasurement Methodology **Amortization Protected** (NOTE D) Line No. Account (NOTE A) **Description of Account** Act (NOTE C) Unprotected Period **Deferred Tax Account (NOTE** B) 1a 1b 1c 1d 1e 1f 1g 1h 1i 1j NOTE E **Regulatory Deferral Accounts** 182.3 Regulatory Asset 2a Regulatory Liability 2b 254 2c NOTE E Total For Accounting Entries (Sum of Lines 1a through 2_) 3

1	J	К	L	М	N Tax Expense	0	P 12/31/20	Q Ending	R
Excess ADIT Regulatory Offset	Excess ADIT in Utility Deferrals	Balance Sheet Account Reclassific ations	Balance She	eet Entries 254	410/411 Excess Amortization	410/411 Deferred Tax Expense/ (Benefit)	Excess ADIT Regulator y Offset Sum of Cols (I) - (O)	Excess ADIT in Utility Deferrals	Reference
							-		
							-		
								•	
	-	-	-	-	-	-	-	-	

NOTE F

NOTE A: In order to ensure ratebase neutrality, AEP utilizes the fourth digit of its seven digit FERC Tax subaccount numbers to identify balances associated with utility operations vs regulatory reporting requirements. A "1" in the fourth digit of a FERC tax account refers to the utility operations balances or activity. Accounts with the "1" designation will be included in the determination of ratebase to be recovered in the formula rate. A "4" in the fourth position of the account number indicates accounts used to track regulatory accounting requirements. The excess ADIT amounts recorded in accounts with the "4" designation will be contra to the "1" balance, which will ensure that in the formula rate the excess or deficiency amounts will be part of ratebase, but at the total FERC account level the tax liability or asset will be recorded at the current Federal FIT rate. The amounts recorded in the "4" accounts will be offset on a net basis in the regulatory asset or liability subaccount established for this purpose.

NOTE B: The amount of the FIT gross up to recorded on regulatory assets and liabilities will be reported on the first line of ADIT accounts provided for each specific change in tax rates.

NOTE C: The amounts of the remeasurement shown here are as of the effective date of the change in tax rates and will remain static on this workpaper.

NOTE D: {REFERENCE OR CITE TO APPROVAL OF AMORTIZATION PERIOD FOR UNPROTECTED EXCESS OR DEFICIENT ADIT}

NOTE E: In the event of future tax rate changes, additional lines will be inserted in both the Total Company and Transmission Functional sections above as required to reflect any new ADIT or regulatory deferral accounts that may be necessary to track that tax rate change.

NOTE F: The amount of excess amortization entries shown in lines 1a through 1h are shown as a debit or credit to the ADIT account from which it is being amortized. The total in line 3 is the offset recorded to the 410/411 account and will tie to the total company amount of excess or deficient ADIT amortization shown on line 102 of the cost of service.

Cost of Service Formula Rate Using Actual/Projected FF1 Balances Worksheet C Supporting Working Capital Rate Base Adjustments TRANSMISSION COMPANY (B) (D) (F) (G) (A) (C) Materials & Supplies <u>Line</u> Number Balance @ December Source 31, Balance @ December 31, Average Balance for Transmission Materials & Supplies General Materials & Supplies FF1, p. 227, ln 8, Col. (c) & (b) FF1, p. 227, ln 11, Col. (c) & (b) Stores Expense (Undistributed) – Account 163 FF1, p. 227, ln 16, Col. (c) & (b) Prepayment Balance Summary (Note 1) Transmission 100% Transmission **Total Included** Average of Excludable Transmission Plant Labor YE Balance Balances Related Related Related

	=	Prepayments Account 165 - Balance @ 12/31/								
		_	Excludable	100% Transmission	Transmission Plant	Transmission Labor	Total Included in Ratebase			
Acc. No.	Description	YE Balance	Balances	Related	Related	Related	(E)+(F)+(G)	Explanation		
			-		-		-			
			-		-		-			
			-			-	-			
			-				-			
			-			-	-			
			-				-			
			-				-			
						-	-			
			-				-			
	_		<u> </u>			-	-			
	Subtotal - Form 1, p 111.57.c	0	0	0	0	0	0	•		
		Prepayments Accou	ınt 165 - Balance @ 12/31/							

0

				Excludable	100% Transmission	Transmission Plant	Transmission Labor	Total Included in Ratebase	
20	Acc. No.	<u>Description</u>	YE Balance	Balances	Related	Related	Related	(E)+(F)+(G)	<u>Explanation</u>
21						0		-	
22						0		-	
23						0		-	
24								-	
25				0				-	
26				0				-	
27				0				-	
28				0				-	
29							0	-	
30				0				-	
31				0				-	
		Subtotal - Form 1, p 111.57.d							_

Prepayment Balance will not include: (i) federal and state income tax payments made to offset additional tax liabilities resulting (or expected to result) from prior federal or state audits or from the filing of one or more amended income tax returns; (ii) outstanding income tax refunds due to [company] resulting (or expected to result) from prior federal or state audits or from the filing of one or more amended income tax returns; or (iii) prepayments of federal or teteral or state adults or not me image of one or more amended income tax feturins, or (iii) prepayments or received state income taxes which are attributable to income earned during periods prior to January 1 of the year depicted in the Balance Sheet (as described in USofA Account 236).

Totals as of December 31, Totals as of December 31,

Average Balance

(H)

in Ratebase

(E)+(F)+(G)

(I)

Cost of Service Formula Rate Using Actual/Projected FF1 Balances

Worksheet D Supporting IPP Credits TRANSMISSION COMPANY

	AEPTRANSMISSION COMPANY	
<u>Line</u>	(A)	(B)
<u>Number</u>	Description	
1 2	Net Funds from IPP Customers 12/31/ (FORM 1, P269) Interest Expense (Company Records – Note 1)	-
3	Revenue Credits to Generators (Company Records – Note 1)	_
4	Other Adjustments	
5	Accounting Adjustment (Company Records – Note 1)	
6		-
7	Net Funds from IPP Customers 12/31/ (FORM 1, P269)	-
8	Average Balance for Year as Indicated in Column ((ln 1 + ln 7)/2) On this worksheet Company Records refers to AEP TRANSMISSION	-
Note 1	COMPANY 's general ledger.	

Cost of Service Formula Rate Using Actual/Projected FF1 Balances

Worksheet E Supporting Revenue Credits

AEP _____ TRANSMISSION COMPANY

		<u>(a)</u>	<u>(b)</u>	<u>(c)</u>
Line		<u>Total</u>	Non-	
Number	<u>Description</u>	<u>Company</u>	Transmission	<u>Transmission</u>
1	Account 450, Forfeited Discounts (FF1 p.300.16.(b); Company Records - Note 1)		-	
2	Account 451, Miscellaneous Service Revenues (FF1 p.300.17.(b); Company Records - Note 1)		-	
3	Account 454, Rent from Electric Property (FF1 p.300.19.(b); Company Records - Note 1)		-	
4	Account 4560015, Associated Business Development - (Company Records - Notes 1, 2)		-	
5	Account 456 - Other Electric Revenues - (Company Records - Notes 1, 2)		-	
5a	Account 457.1, Regional Control Service Revenues (FF1 p.300.23.(b); Company Records - Note 1)			
5b	Account 457.2, Miscellaneous Revenues (FF1p.300.24.(b); Company Records - Note 1)			
6	Subtotal - Other Operating Revenues (Company Total equals (FF1 p. 300.26.(b))		-	
7	Accounts 4470004 & 4470005, Revenues from Grandfathered Transmission Contracts - (Company Records - Note 1)		-	
8	Total Other Operating Revenues To Reduce Revenue Requirement			
9	Facility Credits under PJM OATT Section 30.9			-
Note 1	The total company data on this worksheet comes from the indicated FF1 source, or AEP TRANSMISSION COMPANY 's general ledger. The functional amounts identified as transmission revenue also come from the general ledger.			
Note 2	The total of line 4 and line 5 will equal total Account 456 as listed on FF1 p.300.21-22.(b)			

AEPTCo subsidiaries in PJM Cost of Service Formula Rate Using Actual/Projected FF1 Balances Worksheet F Supporting Allocation of Specific O&M or A&G Expenses TRANSMISSION COMPANY

(C) (D) (F) (A) (B) **(E)** 100% <u>Line</u> Number 100% Transmission Expense <u>Description</u>
Regulatory O&M Deferrals & Amortizations Item No. Non-Transmission Specific Explanation 3 Total Detail of Account 561 Per FERC Form 1 561.1 - Load Dispatch - Reliability
561.2 - Load Dispatch - Monitor & Operate Trans System
561.3 - Load Dispatch - Trans Service & Scheduling
561.4 - Scheduling, System Control & Dispatch
561.5 - Reliability, Planning and Standards Development
561.6 - Transmission Service Studies
561.7 - Generation Interconnection Studies
561.8 - Reliability, Planning and Standards Development Services

Total of Account 561

Account 928 FF1 p 321.85.b FF1 p 321.86.b FF1 p 321.87.b FF1 p 321.88.b FF1 p 321.89.b FF1 p 321.90.b FF1 p 321.91.b 10 11 12 13 14 Account 928 15 16 17 18 19 20 21 Total (FERC Form 1 p.323.189.b) Account 930.1 22 23 24 25 26 27 28 29 30 31 32 33 34 35 36 37 38 Total (FERC Form 1 p.323.191.b) Account 930.2 39 40 41 42 43 Total (FERC Form 1 p.323.192.b)

Cost of Service Formula Rate Using Actual/Projected FF1 Balances Worksheet G Supporting - Development of Composite State Income Tax Rate

AEP TRANSMISSION COMPANY ____ Tax Rate 1 Apportionment Factor – Note 1 Effective State Tax Rate Tax Rate Apportionment Factor – Note 1 Effective State Tax Rate Tax Rate Apportionment Factor – Note 1 Effective State Tax Rate Tax Rate Apportionment Factor – Note 1 Effective State Tax Rate Tax Rate Apportionment Factor – Note 1 Effective State Tax Rate

Note 1 Apportionment Factors are determined as part of the Company's annual tax return for that jurisdiction.

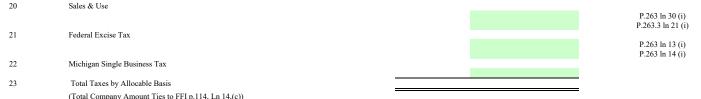
Total Effective State Income Tax Rate

AEPTCo subsidiaries in PJM Cost of Service Formula Rate Using Actual/Projected FF1 Balances Worksheet H Supporting Taxes Other than Income AEP ______ TRANSMISSION COMPANY (B) (C)

		AEP TRANSMIS	SION COMPAINT			
	(A)	(B)	(C)	(D)	(E)	(F)
e		Total				
_	Account	Company	Property	Labor	Other	Non-Allocable
	Revenue Taxes List Individual Taxes Here	NOTE 1				
	Real Estate and Personal Property Taxes					-
	Real and Personal Property - Jurisdiction #1					
	Real and Personal Property - Jurisdiction #2					
	Real and Personal Property - Jurisdiction #3		=			
	Real and Personal Property - Other Jurisdictions		-			
	Payroll Taxes					
	Federal Insurance Contribution (FICA)			-		
)	Federal Unemployment Tax			-		
	State Unemployment Insurance			-		
2	Line Deliberately Left Blank					
3 4	State Severance Taxes					-
	Miscellaneous Taxes List Individual Taxes Here					
	List individual Taxes Here					-
,					-	
					_	-
					_	
					_	
1						_
						-
	Total Taxes by Allocable Basis (Total Company Amount Ties to FFI p.114, Ln 14,(c)) NOTE 1: The detail of each total company number and its source in the FERC Form			-	-	-
!	(Total Company Amount Ties to FFI p.114, Ln 14,(c))	n 1 is shown on WS H-1. Functional Proper			<u> </u>	
	(Total Company Amount Ties to FFI p.114, Ln 14,(c))	n 1 is shown on WS H-1. Functional Proper Lines 24-58 Column (B)	ty Tax Allocation	Lines 24-58 Column (D)		Total
	(Total Company Amount Ties to FFI p.114, Ln 14,(c)) NOTE 1: The detail of each total company number and its source in the FERC Form	n 1 is shown on WS H-1. Functional Proper			- General	- - Total
	(Total Company Amount Ties to FFI p.114, Ln 14,(c)) NOTE 1: The detail of each total company number and its source in the FERC Form Functionalized Net Plant (TCOS, Lns 33 thru 36)	n 1 is shown on WS H-1. Functional Proper Lines 24-58 Column (B)	ty Tax Allocation	Lines 24-58 Column (D)		Total
! !	(Total Company Amount Ties to FFI p.114, Ln 14,(c)) NOTE 1: The detail of each total company number and its source in the FERC Form	n 1 is shown on WS H-1. Functional Proper Lines 24-58 Column (B)	ty Tax Allocation	Lines 24-58 Column (D)		- - Total
	(Total Company Amount Ties to FFI p.114, Ln 14,(c)) NOTE 1: The detail of each total company number and its source in the FERC Form Functionalized Net Plant (TCOS, Lns 33 thru 36) JURISDICTION Percentage of Plant in JURISDICTION (Ln 24 * Ln 25)	n 1 is shown on WS H-1. Functional Proper Lines 24-58 Column (B)	ty Tax Allocation	Lines 24-58 Column (D)		- - Total
	(Total Company Amount Ties to FFI p.114, Ln 14,(c)) NOTE 1: The detail of each total company number and its source in the FERC Form Functionalized Net Plant (TCOS, Lns 33 thru 36)	n 1 is shown on WS H-1. Functional Proper Lines 24-58 Column (B)	ty Tax Allocation	Lines 24-58 Column (D)		Total
	(Total Company Amount Ties to FFI p.114, Ln 14,(c)) NOTE 1: The detail of each total company number and its source in the FERC Form Functionalized Net Plant (TCOS, Lns 33 thru 36)	n 1 is shown on WS H-1. Functional Proper Lines 24-58 Column (B)	ty Tax Allocation	Lines 24-58 Column (D)		Total
	(Total Company Amount Ties to FFI p.114, Ln 14,(c)) NOTE 1: The detail of each total company number and its source in the FERC Form Functionalized Net Plant (TCOS, Lns 33 thru 36) JURISDICTION Percentage of Plant in JURISDICTION (Ln 24 * Ln 25) Less: Net Value of Exempted Generation Plant Taxable Property Basis (Ln 26 - Ln 27) Relative Valuation Factor	n 1 is shown on WS H-1. Functional Proper Lines 24-58 Column (B)	ty Tax Allocation	Lines 24-58 Column (D)		Total
	(Total Company Amount Ties to FFI p.114, Ln 14,(c)) NOTE 1: The detail of each total company number and its source in the FERC Form Functionalized Net Plant (TCOS, Lns 33 thru 36) JURISDICTION Percentage of Plant in JURISDICTION Net Plant in JURISDICTION (Ln 24 * Ln 25) Less: Net Value of Exempted Generation Plant Taxable Property Basis (Ln 26 - Ln 27) Relative Valuation Factor Weighted Net Plant (Ln 28 * Ln 29)	n 1 is shown on WS H-1. Functional Proper Lines 24-58 Column (B)	ty Tax Allocation	Lines 24-58 Column (D)		Total
	(Total Company Amount Ties to FFI p.114, Ln 14,(c)) NOTE 1: The detail of each total company number and its source in the FERC Form Functionalized Net Plant (TCOS, Lns 33 thru 36)	n 1 is shown on WS H-1. Functional Proper Lines 24-58 Column (B)	ty Tax Allocation	Lines 24-58 Column (D)		Total
	(Total Company Amount Ties to FFI p.114, Ln 14,(c)) NOTE 1: The detail of each total company number and its source in the FERC Form Functionalized Net Plant (TCOS, Lns 33 thru 36)	n 1 is shown on WS H-1. Functional Proper Lines 24-58 Column (B)	ty Tax Allocation	Lines 24-58 Column (D)		Total
	(Total Company Amount Ties to FFI p.114, Ln 14,(c)) NOTE 1: The detail of each total company number and its source in the FERC Form Functionalized Net Plant (TCOS, Lns 33 thru 36)	n 1 is shown on WS H-1. Functional Proper Lines 24-58 Column (B)	ty Tax Allocation	Lines 24-58 Column (D)		Total
	(Total Company Amount Ties to FFI p.114, Ln 14,(c)) NOTE 1: The detail of each total company number and its source in the FERC Form Functionalized Net Plant (TCOS, Lns 33 thru 36)	n 1 is shown on WS H-1. Functional Proper Lines 24-58 Column (B)	ty Tax Allocation	Lines 24-58 Column (D)		Total
	(Total Company Amount Ties to FFI p.114, Ln 14,(c)) NOTE 1: The detail of each total company number and its source in the FERC Form Functionalized Net Plant (TCOS, Lns 33 thru 36) JURISDICTION Percentage of Plant in JURISDICTION Net Plant in JURISDICTION (Ln 24 * Ln 25) Less: Net Value of Exempted Generation Plant Taxable Property Basis (Ln 26 - Ln 27) Relative Valuation Factor Weighted Net Plant (Ln 28 * Ln 29) General Plant Allocator (Ln 31 / (Total - General Plant)) Functionalized General Plant (Ln 31 * General Plant) Weighted JURISDICTION Plant (Ln 30 + 32) Functional Percentage (Ln 33.7total Ln 33) Net Plant in JURISDICTION (Ln 24 - Ln 26)	n 1 is shown on WS H-1. Functional Proper Lines 24-58 Column (B)	ty Tax Allocation	Lines 24-58 Column (D)		Total
	(Total Company Amount Ties to FFI p.114, Ln 14,(c)) NOTE 1: The detail of each total company number and its source in the FERC Form Functionalized Net Plant (TCOS, Lns 33 thru 36)	n 1 is shown on WS H-1. Functional Proper Lines 24-58 Column (B)	ty Tax Allocation	Lines 24-58 Column (D)		Total
	(Total Company Amount Ties to FFI p.114, Ln 14,(c)) NOTE 1: The detail of each total company number and its source in the FERC Form Functionalized Net Plant (TCOS, Lns 33 thru 36)	n 1 is shown on WS H-1. Functional Proper Lines 24-58 Column (B)	ty Tax Allocation	Lines 24-58 Column (D)		Total
	(Total Company Amount Ties to FFI p.114, Ln 14,(c)) NOTE 1: The detail of each total company number and its source in the FERC Form Functionalized Net Plant (TCOS, Lns 33 thru 36) JURISDICTION Percentage of Plant in JURISDICTION (Ln 24 * Ln 25) Less: Net Value of Exempted Generation Plant Taxable Property Basis (Ln 26 - Ln 27) Relative Valuation Factor Weighted Net Plant (Ln 28 * Ln 29) General Plant Allocator (Ln 31 / (Total - General Plant)) Functionalized General Plant (Ln 31 * General Plant) Weighted JURISDICTION Plant (Ln 30 + 32) Functional Percentage (Ln 33.7total Ln 33) Net Plant in JURISDICTION (Ln 24 - Ln 26) Less: Net Value of Exempted Generation Plant Taxable Property Basis (Ln 36 - Ln 37) Relative Valuation Factor	n 1 is shown on WS H-1. Functional Proper Lines 24-58 Column (B)	ty Tax Allocation	Lines 24-58 Column (D)		Total
	(Total Company Amount Ties to FFI p.114, Ln 14,(c)) NOTE 1: The detail of each total company number and its source in the FERC Form Functionalized Net Plant (TCOS, Lns 33 thru 36) JURISDICTION Percentage of Plant in JURISDICTION (Ln 24 * Ln 25) Less: Net Value of Exempted Generation Plant Taxable Property Basis (Ln 26 - Ln 27) Relative Valuation Factor Weighted Net Plant (Ln 28 * Ln 29) General Plant Allocator (Ln 31 / (Total - General Plant)) Functionalized General Plant (Ln 31 * General Plant) Weighted JURISDICTION Plant (Ln 30 + 32) Functional Percentage (Ln 33/Total Ln 33) Net Plant in JURISDICTION (Ln 24 - Ln 26) Less: Net Value of Exempted Generation Plant Taxable Property Basis (Ln 36 - Ln 37) Relative Valuation Factor Weighted Net Plant (Ln 31 * Ln 38)	n 1 is shown on WS H-1. Functional Proper Lines 24-58 Column (B)	ty Tax Allocation	Lines 24-58 Column (D)		Total
	(Total Company Amount Ties to FFI p.114, Ln 14,(c)) NOTE 1: The detail of each total company number and its source in the FERC Form Functionalized Net Plant (TCOS, Lns 33 thru 36)	n 1 is shown on WS H-1. Functional Proper Lines 24-58 Column (B)	ty Tax Allocation	Lines 24-58 Column (D)		Total
	(Total Company Amount Ties to FFI p.114, Ln 14,(c)) NOTE 1: The detail of each total company number and its source in the FERC Form Functionalized Net Plant (TCOS, Lns 33 thru 36) JURISDICTION Percentage of Plant in JURISDICTION Net Plant in JURISDICTION (Ln 24 * Ln 25) Less: Net Value of Exempted Generation Plant Taxable Property Basis (Ln 26 - Ln 27) Relative Valuation Factor Weighted Net Plant (Ln 28 * Ln 29) General Plant Allocator (Ln 31 / (Total - General Plant)) Functionalized General Plant (Ln 31 * General Plant) Weighted JURISDICTION Plant (Ln 30 + 32) Functional Percentage (Ln 33/Total Ln 33) Net Plant in JURISDICTION (Ln 24 - Ln 26) Less: Net Value of Exempted Generation Plant Taxable Property Basis (Ln 36 - Ln 37) Relative Valuation Factor Weighted Net Plant (Ln 37 * Ln 38) General Plant Allocator (Ln 39 / (Total - General Plant)) Functionalized General Plant (Ln 41 * General Plant)) Functionalized General Plant (Ln 41 * General Plant))	n 1 is shown on WS H-1. Functional Proper Lines 24-58 Column (B)	ty Tax Allocation	Lines 24-58 Column (D)		Total
) 1 1 2 2 3 4 4 4 5 5 6 6 7 7 3 3 9 9 9 1 1 2 2 3 4 4 5 5 6 7 7 7 3 3 9 9 9 1 1 2 2 3 3 4 5 5 6 7 7 7 8 9 9 9 9 9 9 9 9 9 9 9 9 9 9 9 9	(Total Company Amount Ties to FFI p.114, Ln 14,(c)) NOTE 1: The detail of each total company number and its source in the FERC Form Functionalized Net Plant (TCOS, Lns 33 thru 36)	n 1 is shown on WS H-1. Functional Proper Lines 24-58 Column (B)	ty Tax Allocation	Lines 24-58 Column (D)		Total

AEPTCo subsidiaries in PJM Cost of Service Formula Rate Using Actual/Projected FF1 Balances Worksheet H page 2 Form 1 Source Reference of Company Amounts on WS H AEP______TRANSMISSION COMPANY

	(A)		(B)	(C)	(D)		
Line No.	Annual Tax Expenses by Type (Note 1)		Total Company	FERC FORM 1 Tie-Back	FERC FORM 1 Reference		
1 2	Revenue Taxes Gross Receipts Tax				P.263.1 ln 7 (i) P.263.2 ln 3 (i)		
3 4	(A) "Real Estate and Personal Propety Tax Detail Annual Tax Expenses by Type (Note 1)" Real Estate and Personal Property Taxes Total (Ln 4 + Ln 5 + Ln 6 + Ln 7) Real and Personal Property -	(B) Tax Year	(C) Total Comapny	(D) FERC FORM 1 Tie-Back	P.263.2 ln 4 (i) (E) FERC FORM 1 Reference	(F) Tax Year Factor (Note 2)	(G) Transmission Function (Note 2)
5	Real and Personal Property - Real and Personal Property -						
7	Real and Personal Property - Other Jurisdictions						
Line	<u>(A)</u>			(C)	(D)		
No. 8 9	Annual Tax Expense by Type (Note 1) Payroll Taxes Federal Insurance Contribution (FICA)			FERC FORM 1 Tie-Back	FERC FORM 1 Reference		
10	Federal Unemployment Tax				P.263 ln 6 (i) P.263 ln 9 (i)		
11 12	State Unemployment Insurance Line Left Deliberately Blank				P.263.1 ln 23 (i) P.263.3 ln 16 (i)		
13	State Severance Taxes Miscellaneous Taxes						
15	State Business & Occupation Tax				P.263 ln 21 (i) P.263 ln 22 (i)		
16	State Public Service Commission Fees				P.263 ln 26 (i) P.263.3 ln 20 (i)		
17	State Franchise Taxes				P.263.1 ln 18 (i) P.263.4 ln 27 (i)		
18 19	State Lic/Registration Fee Misc. State and Local Tax				P.263.1 ln 15 (i) P.263.4 ln 21 (i)		
					P.263.1 ln 12 (i)		



(Total Company Amount Ties to FFI p.114, Ln 14,(c))

Note 1: The taxes assessed on each transmission company can differ from year to year and between transmission companies by both the type of taxes and the states in which they were assessed. Therefore, for each company, the types and jurisdictions of tax expense recorded on this page could differ from the same page in the same company's prior year template or from this page in other transmission companies' current year templates. For each update, this sheet will be revised to ensure that the total activity recorded hereon equals the total reported in account 408.1 on P. 114, Ln 14,(c) of the Ferc Form 1.

Note 2: The transmission functional amounts for any Real Estate and Property taxes listed on pages 263 of the FERC Form 1 will be allocated using the transmission functional allocator calculated for each state in Worksheet H of the applicable year that the taxes were assessed. Real and Personal Property - Other Jurisdictions will be allocated using the Gross Plant Allocator from the applicable year..

AEPTCo subsidiaries in PJM
Cost of Service Formula Rate Using Actual/Projected FF1
Balances
Worksheet I RESERVED
AEP ______ TRANSMISSION COMPANY

RESERVED FOR FUTURE USE

AEPTCo subsidiaries in PJM

Cost of Service Formula Rate Using Actual/Projected FF1 Balances
Worksheet J Supporting Calculation of PROJECTED PJM RTEP Project Revenue Requirement Billed to Benefiting Zones AEP _____TRANSMISSION COMPANY

Regional Billir		•		•								
	'R' with hypothetical		rease in ROE for Iden	itified Projects								
	entives (TCOS, ln 138)				11.49%							
	Incentive Adder											
	ditional basis point ince		1 . 1 . 1 . 2		00.1 164.1 1166							
Determine R	(cost of long term debt)						
	T T D1	<u>%</u>	Cost	Weighted co	0.000%							
	Long Term Debt	0.00%	0.00%									
	Preferred Stock	0.00%	0.00%		0.000%							
	Common Stock	0.00%	11.49%		0.000%				SUMMARY OF PROJECTED A	ANNUAL RTEP RE	VENUE REQUII	
			R =		0.000%					Day Daguina	W Incentives	Incentive Amounts
			K-		0.00070					Rev Require	w incentives	Amounts
B. Determine	Return using 'R' with	hypothetical h	pasis point ROE incre	ase for Identified Proi	ects.				PROJECTED YEAR	_	_	\$
Rate Base (T		, p	, p		-							·
R (fom A. al					0.000%							
Return (Rate	,				-							
,	Income Taxes using F	Return with hyp	othetical basis point	ROE increase for Ide	ntified Projects.							
Return (fron					-							
Effective Tax	Rate (TCOS, ln 97)				0.00%							
Income Tax O	Calculation (Return x)	CIT)			_							
ITC Adjustme		· ·			_							
	red Income Tax				_							
	f Permanent Differences				_							
Income Taxes	s				_							
II. Calculate Net	Plant Carrying Charge	e Rate (Fixed C	harge Rate or FCR) v	vith hypothetical								
basis point RO												
	Annual Revenue Req	uirement less r	eturn and Income Tax	es.								
	nue Requirement (TCC						_					
	nts (TCOS, Ln 80)	,,					_					
Return (TCC							_					
	s (TCOS, ln 108)						_					
	nue Requirement, Less	ease Payments	Return and Taxes			-						
	Annual Revenue Req			nt increase in ROE								
	ue Requirement, Less L			in mercuse in reozi			_					
Return (fron		ease payments,	iteturii unu Tunes				_					
,	s (from I.C. above)						_					
	nue Requirement, with	Basis Point ROI	E increase									
	& Amortization (TCOS		in mereuse				_					
	Req, w/ Basis Point RO		Depreciation									
Timuu Teeri	red, w Basis rome res	L'increase, ress	Depresiation									
C Determine	FCR with hypothetica	al basis noint B	OE increase									
	ssion Plant (TCOS, ln 3		to 2 mereuser				_					
	nue Requirement, with		E increase				_					
	asis Point increase in RC						0.00%					
	Req, w / Basis Point Ro		s Dep.				-					
	asis Point ROE increase.						0.00%					
	preciation (TCOS, ln 1						0.00%					
	CR with Basis Point R	,	s Depreciation				0.00%					
II		, 100	1									
	Composite Depreciati	on Rate										
	mission Plant Balance fo		19				-					
	iation and Amortization						_					
Composite Dep			•				0.00%	Note 1: Until AEP	TRANSMISSION COMPANY establis	hes Transmission pla	nt in service the	denreciation exper
	fe for Composite Depre	ciation Rate							ge will be calculated as in the Operating (
Average Life in								The calculation for AEP	TRANSMISSION COMPANY is			

$\label{eq:control_control_control} TransCo\ Worksheet\ J-\ ATRR\ PROJECTED\ Calculation\ for\ PJM\ Projects\ Charged\ to\ Benefiting\ Zones$

I

V Determine the Revenue Requirement, and Additional

. Revenue Requirement for facilities receiving incentives.

A. Base Plan Facilities	•								
Facilities receiving inco	entives accepted by	FERC in Docket N	No.		(e.g. ER10-925-0	00)	Current Projected Year ARR		_
							Current Projected Year ARR w/ Ince	ntive	
Project Description:						1	Current Projected Year Incentive AF	IR .	-
Details Investment		Current Year					CHMILATIVE DISTORY OF BR	OJECTED ANNUAL REVENUE RE	OHIDEMENTS
Service Year (yyyy)		ROE increase acce	nted by FFR	C (Basis Points)			CUMMULATIVE HISTORY OF PRO		
berriee real (JJJJ)		FCR w/o incentive		C (Dubio I omio)				H & WITHOUT INCENTIVES) FROM	
Service Month (1-12)		depreciation	,			0.00%	YEAR	, , , , , , , , , , , , , , , , , , ,	
		FCR w incentives	approved for						
Ti 6 1 PC		these facilities, less	s dep.			0.00%	TEMPLATE DELOW TO MAIN	EAD HISTORY OF BROJECTED ARE	OVED THE
Useful life							TEMPLATE BELOW TO MAIN	TAIN HISTORY OF PROJECTED ARE	S OVER THE
CIAC (Yes or No)	C	Annual Depreciation	on Expense			_	LIFE OF THE PROJECT.		
							RTEP Projected	RTEP Projected Rev.	
					RTEP Rev.		Rev. Req't.From	Req't.From Prior Year	
Investment	Beginning	Depreciation	Ending	RTEP Rev. Req't.	Req't.	Incentive Rev.	Prior Year Template	Template	
Year	Balance	Expense	Balance	w/o Incentives	with Incentives	Requirement ##	w/o Incentives	with Incentives **	
0	-	-	-	-	-	\$ -			
1	-	-	-	-	-	S -			
2	-	-	-	-	-	S -			
3	-	-	-	-	 -	S -			
4	-	-	-	-	-	S -			
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12	-	-	-	-	-	S -			
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21	-	-	-	-	-	S -			
22	-	-	-	-	-	S -			
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24 25	-	-	-	-	-	S - S -			
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should be incremented by the amount of the incentive revenue calculated for that year on this project.

In order to calculate the proper monthly RTEP billing amount, PJM requires a 12 month revenue requirement for each RTEP project. As a result, notwithstanding the fact that the project was in service for a partial year, the project revenue requirement in the year that the project goes into service has been annualized (shown at the full-year level) so that PJM will collect the correct monthly billings.

^{**} This is the total amount that needs to be reported to PJM for billing to all regions.

^{##} This is the calculation of additional incentive revenue on projects deemed by the FERC to be eligible for an incentive return. This additional incentive requirement is applicable for the life of this specific project. Each year the revenue requirement calculated for PJM should be incentive requirement and the incentive requirement

AEPTCo subsidiaries in PJM Cost of Service Formula Rate Using Actual/Projected FF1 Balances Worksheet K Supporting Calculation of TRUE-UP PJM RTIPP Project Revenue Requirement Billed to Benefiting Zones AEP _____ TRANSMISSION COMPANY

Page 1 of 2

									rage	1 01 2	
I.	Calculate Return and A. Determine 'R' with					ng.					
	ROE w/o incentives (Project ROE Incentive)		11.49 % 0						
	ROE with additional () basis point inc	entive				SUMMARY OF TRUED-UP ANNU.	AL REVENUE	REQUIREMENTS		
	Determine R (cost of	f long term debt	, cost of preferred sto	ock and equity percentag	ge is from the TCOS, lns 164 th	rough 166)		Rev Requi	re W Incent		entive ounts
		<u>%</u>	Cost	Weighted cost	-		TRUE-UP YEAR	_			
	Long Term Debt	0.00%	0.00%	0.000%			As Projected in Prior Year W	21		3	-
	Preferred Stock	0.00%	0.00%	0.000%			Actual after True	-up \$	- \$ -	\$	-
	Common Stock	0.00%	0.00% R =	11.490% 0.000%			True-up of ARR For		-		-
	B. Determine Return Rate Base (TCOS, In		hypothetical 0 basis		for Identified Projects.						
	R (fom A. above)			0.000							
	,			,,,							
	Return (Rate Base x C. Determine Income		Return with hypothe	tical 0 basis point ROI	E increase for Identified Projection	cts.					
	Return (from B. abov Effective Tax Rate (T			0.00%							
	Income Tax Calculation	on (Return x	CIT)	-							
	ITC Adjustment Excess Deferred Inc	come Tax									
	Tax Affect of Perma		ices	-							
II.	Income Taxes Calculate Net Plant Ca hypothetical 0 basis point ROE incre A. Determine Annual Annual Revenue Requ	ase. I Revenue Req	uirement less return								
	Lease Payments (TC0	OS, Ln 80)	73, III 1)		-						
	Return (TCOS, ln 10	19)			-						
	Income Taxes (TCO	S, ln 108)			=						
	Annual Revenue Requ	uirement, Less l	Lease payments, Retu	ırn and Taxes	-						
	B. Determine Annual	Revenue Req	uirement with hypot	thetical 0 basis point in	ncrease in ROE.						
	Annual Revenue Requ Return (from I.B. ab	uirement, Less l ove)	Lease payments, Retu	ırn and Taxes	-						
	Income Taxes (from I Annual Revenue Requ) Basis Point ROE in	crease	= -						
	Depreciation (TCOS, Annual Rev. Req, w/ increase, less Depreciati	0 Basis Point R	OE		=						
	C. Determine FCR w Net Transmission Plan	ith hypothetics nt (TCOS, ln 3	3)		-						
	Annual Revenue Requ FCR with 0 Basis Poi			crease	0.00%						
	Annual Rev. Req, w / FCR with 0 Basis Poin FCR less Depreciation Incremental FCR with increase, less Deprecial	nt ROE increase n (TCOS, ln 10 n 0 Basis Point l	e, less Depreciation	ep.	- 0.00% <u>0.00%</u> 0.00%						
III.	Calculation of Compos	site Depreciati	on Rate								
	Average Transmission I	Plant Balance fo	or TCOS, ln 19			-					
	Annual Depreciation an Composite Depreciation		Expense (TCOS, ln	83)		0.00%	Note 1: Until AEP		SSION COMPANY		
	Depreciable Life for Co	omposite Depre	ciation Rate			-	plant in service the deprecial calculated as in the Operatin	g Company for		ocket No. ER(08-1329. Th
	Average Life in Whole	Years				-	calculation for AEPP.	I KANSM	1331ON COMPAN	i is snown on	worksneet
	~										

IV. Determine the Revenue Requirement, and Additional Revenue Requirement for facilities receiving incentives. A. Base Plan Facilities

Current Year ROE increase accepted by FERC (Basis Points)

Annual Depreciation Expense

Depreciation

FCR w/o incentives, less depreciation FCR w/incentives approved for these facilities, less dep.

Ending

Average

Facilities receiving incentives accepted by FERC in Docket No.

Beginning

(e.g. ER10-925-000)

RTEP Rev Req't. with

RTEP Rev Req't. w/o

0.00%

Incentive Rev. Requirement ##

Project Description:

Details Investment Service Year (yyyy) Service Month (1-12)

Investment

Useful life CIAC (Yes or No)

	Rev Require	W Incentives	Incentive Amounts
Prior Yr	•		
Projected	-	-	-
Prior Yr True-Up			-
True-Up			
Adjustment	-	-	-

TRUE UP OF PROJECT REVENUE REQUIREMENT FOR PRIOR YEAR; CUMULATIVE HISTORY OF TRUED-UP ANNUAL REVENUE REQUIREMENTS: INPUT TRUE-UP ARR (WITH & WITHOUT INCENTIVES) FROM EACH PRIOR YEAR

TEMPLATE BELOW TO MAINTAIN HISTORY OF TRUED-UP ARRS OVER THE

LIFE OF T	HE PROJECT.			
RTEP Projected Rev. Reg't.From Prior Year WS J	RTEP Rev Req't True- up w/o	RTEP Projected Rev. Req't.From Prior Year WS J with	RTEP Rev Req't True-up with	True-up of Incentive with
w/o Incentives	Incentives \$ -	Incentives **	Incentives **	Incentives **
	\$ - \$ - \$ -		S - S - S -	\$ - \$ -
				\$ - \$ -
	S - S -		\$ - \$ -	\$ - \$ -
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			-	-

** This is the total amount that needs to be reported to PJM for billing to all regions.
This is the calculation of additional incentive revenue on projects deemed by the FERC to be eligible for an incentive return. This
additional incentive requirement is applicable for the life of this specific project. Each year the revenue requirement calculated for PJM
should be incremented by the amount of the incentive revenue calculated for that year on this project.

AEPTCo subsidiaries in PJM
Cost of Service Formula Rate Using Actual/Projected FF1 Balances
Worksheet L RESERVED
AEP ______ TRANSMISSION COMPANY

RESERVED FOR FUTURE USE

AEPTCo subsidiaries in PJM

Cost of Service Formula Rate Using Actual/Projected FF1 Balances Worksheet M Supporting Calculation of Capital Structure and Weighted Average Cost of Capital

AEP WEST VIRGINIA TRANSMISSION COMPANY

		Average Balance of Common Equity							
Line No		Proprietary Capital	Less: Preferred Stock	Less Undistribut ed Sub Earnings (Acct 216.1)	Less AOCI (Acct	Average Balance of Common Equity (f)=(b)-(c)-			
	(a)	(b)	(c)	(d)	(e)	(d)-(e)			
	(Note A)	(FF1 112.16)	(FF1 250-251)) (FF1 112.12)	(FF1 112.15)				
1	December Prior to Rate Year	-	-	-	-	-			
2	January		-	-	-	-			
3	February	-	-	-	-	-			
4	March	-	-	-	-	-			
5	April	-	-	-	-	-			
6	May		-	_	-	-			
7	June		-	_	-	-			
8	July		-	_	-	-			
9	August	-	-	-	-	-			
10	September		-	-	_	-			
11	October		-	_	-	-			
12	November		_	_	_	-			
13	December of Rate Year		-	_	-	-			
14		·s-	-	-	-	-			

			Average Balance of Long Term Debt						
							Gross		
				Acct 223	Acct 224		Proceeds		
			Less:	LT Advances	Senior	Less: Fair	Outstandin		
Line			Reacquired	from Assoc.	Unsecured	Value	g Long-		
No	Month	Bonds	Bonds	Companies	Notes	Hedges	Term Debt		
	(a)	(b)	(c)	(d)	(e)	(f)	(g)=(b)-		

						(c)+(d)+(e) -(f)
(Note A)	(FF1 112.18)	(FF1 112.19)	(FF1 112.20)	(FF1 112.21)	FF1, page 257, Col. (h) - Note 1	
15 December Prior to Rate Year	-	-	-	-	-	-
16 January	-	-	-	-	-	-
17 February	-	-	-	-	-	-
18 March	_	-	-	-	-	-
19 April	-	-	-	-	-	-
20 May	-	-	-	-	-	-
21 June	-	-	-	-	-	-
22 July	-	-	-	-	-	-
23 August	-	_	-	-	-	-
24 September	_	-	-	-	-	-
25 October	-	_	-	-	-	-
26 November	-	_	-	-	-	-
27 December of Rate Year	-	-	-	-	-	-
28 Average of the 13 Monthly Balances		-	-	-	-	-

NOTE 1: The balance of fair value hedges on outstanding long term debt are to be excluded from the balance of long term debt included in the formula's capital structure. (Page 257 Column H of the FF1)

<u>Development of Cost of Long Term Debt Based on Average Outstanding Balance</u>

	(a)	(b)	(c)	(d)	(e)	(f)	(g)
29	Annual Interest Expense for 2017						
	Interest on Long Term Debt - Accts						
30	221 - 224 (256-257.33.i)			-			
	Less: Total Hedge Gain/Expense Accu	ımulated					
	from p 256-257, col. (i) of FERC Form	n 1 included					
31	in Ln 30 and shown in 43 below.			-			
	Amort of Debt Discount & Expense -						
32	Acct 428 (117.63.c)			-			
	Amort of Loss on Reacquired Debt -						
33	Acct 428.1 (117.64.c)			-			
	Less: Amort of Premium on Debt -						
34	Acct 429 (117.65.c)			-			
	Less: Amort of Gain on Reacquired						
35	Debt - Acct 429.1 (117.66.c)			-			

36	Total Interest Expense (Ln 30 - 31 + 32 + 33 - 34 - 35)
37	Average Cost of Debt for 2017 (Ln 36/ ln 28 (g))
38	gains) related to interest hedging activities.
	Amortization Period
	(Amortizati HEDGE AMOUNTS BY on of Remaining ISSUANCE (FROM p. 256-257 (i) (Gain)/Loss Unamortize of the FERC Form 1) for 2017 d Balance Beginning Ending
39	or the rate of the
40	
41	
42	
43	Net (Gain)/Loss Hedge Amortization To Be Removed
	velopment of Cost of Preferred
<u>Sto</u>	<u>ck</u>
	Balance of Preferred Stock (Line 14
44	(c)) -
	Dividends on Preferred Stock (Acct
45	437, FF1 118.29))
46	Average Cost of Preferred Stock (Ln 45 / ln 44)

AEPTCo subsidiaries in PJM

Cost of Service Formula Rate Using Actual/Projected FF1 Balances
Worksheet N - Gains (Losses) on Sales of Plant Held For Future Use

AEP TRANSMISSION COMPANY

Note: Gain or loss on plant held for future are recorded in accounts 411.6 or 411.7 respectiviely. Sales will be
funtionalized based on the description of that asset. Sales of transmission assets will be direct assigned; sales of general
assets will be functionalized on labor. Sales of plant held for future use related to generation or distribution will not be
included in the formula.

(A)

(B)

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
Line	Date	Property Description	Function (T) or (G) T = Transmission G = General	Basis	Proceeds	(Gain) / Loss	Functional Allocator	Functional Proceeds (Gain) / Loss	FERC Account (Gain) / Loss
1						-	0.000%		
2						-	0.000%		
3						-	0.000%		
4				Net (Gain) or Loss for				

AEPTCo subsidiaries in PJM

Cost of Service Formula Rate Using Actual/Projected FF1 Balances

Calculation of Post-employment Benefits Other than Pensions Expenses Allocable to Transmission Service

Worksheet O - PBOP Support
AEP TRANSMISSION COMPANY

PBOP	(A)		(B)
1	Calculation of PBOP Expenses		
2	AEP System PBOP Rate		
3	Total AEP System PBOP expenses		
4	Base Year relating to retired personnel		
5	Amount allocated on Labor		
6	Total AEP System Direct Labor Expense		
	AEP System PBOP expense per dollar of direct labor		
7	(PBOP Rate)		
8	Currently Approved PBOP Rate		(0.043)
9	Base PBOP TransCo labor expensed in current year		
10	Allowable TransCo PBOP Expense for current year (I	n 8 * Ln 9)	
11	Direct PBOP Expense per Actuarial Report		
12	Additional PBOP Ledger Entry (From Company Reco	rds)	
13	Medicare Credit		
14	PBOP Expenses From AEP Affiliates (From Company	(Records)	
15	Actual PBOP Expense	(Sum Lines 11-14)	
16	PBOP Adjustment	Line 10 less Line 15	

Note: PBOP Expense will be calculated in accordance with the settlement in Docket ER10-355.

As part of the annual update process, AEP will provide to transmission customers and include in its informational filing an independently prepared actuarial report that includes a ten (10) year forecast of PBOP expenses. During the annual update process conducted for rate year 2018 and every four years thereafter, Worksheet O will be used to determine whether the PBOP allowance rate (\$PBOP per \$Direct O&M Labor) should be adjusted going forward for the next four years. If the annual actuarial report issued during the year of any PBOP rate review projects PBOP costs during the next four years that, when allocated to the AEP Transmission Companies based on their projected direct labor expenses over that same projected four-year period, absent a change in the PBOP Rate, will likely cause the AEP East Transmission Companies to over or under collect their cumulative PBOP expenses by more than 20% of the projected next four year's total PBOP expense, taking into account the net over or under collection of such expenses during the previous four years, the PBOP rate shall be adjusted. In order to determine whether continued use of the then approved PBOP rate is likely to result in the AEP Companies' incurrence of a cumulative allowance of PBOP costs under the formula rate will result in a cumulative over or under-recoery of actual PBOP expenses exceeding 20% over the subsequent four year period, Worksheet O will be used to determine (a) the level of cumulative over or under collections of PBOP expense during the time since the PBOP allowance rate was last set, including carrying costs based on the weighted average cost of capital each year from the formula rate actual transmission cost-of-service (b) the cumulative net present value of projected PBOP costs during the next four years as estimated by the then current actuarial report, assuming a discount rate equal to the actual transmission cost of service average cost of capital for the immediately prior calendar year and (c) the cumulative net present value of continued collections over the next four years based on the projected AEP Transmission Companies direct labor expenses and the then effective PBOP allowance rate assuming a discount rate equal to the prior year weighted average cost of capital. If the absolute value of (a)+(b)-(c) exceeds 20% of (b), then the PBOP allowance rate used in the formula rate calculation shall be changed to the value that will cause the projected result of (a)+(b)-(c) to equal zero. If the projected over or under collection during the next four years, (a)+(b)-(c), is less than 20% of (b), then the PBOP Rate will continue in effect for the next four years at the then effective rate. If it is determined through this procedure AEP Companies will over-recover or under-recover actual PBOP expenses by more than 20% over the subsequent four-year period, AEP shall make a filing under FPA Section 205 to change the PBOP Rate stated in the formula rate shown on Worksheet O. No other changes to the formula rate may be included in that filing.

AEPTCo subsidiaries in PJM

Worksheet - P

DEPRECIATION RATES

FOR TRANSMISSION PLANT PROPERTY ACCOUNTS EFFECTIVE AS OF 1/1/2020

AEP APPALACHIAN TRANSMISSION COMPANY

	PLANT	RATES
	ACCT.	Note 1
TRANSMISSION PLANT		
Energy Storage Equipment	351.0	14.22%
Structures & Improvements	352.0	1.99%
Station Equipment	353.0	2.70%
Towers & Fixtures	354.0	1.64%
Poles & Fixtures	355.0	3.46%
Overhead Conductor	356.0	1.65%
Underground Conduit	357.0	2.49%
Underground Conductors	358.0	4.72%
GENERAL PLANT		
Structures and Improvements	390	1.89%
Office Furniture and Equip.	391	3.21%
Transportation Equipment	392	3.46%
Stores Equipment	393	1.78%
Tools, Shop and Garage Equipment	394	2.59%
Laboratory Equipment	395	3.87%
Power Operated Equipment	396	3.90%
Communications Equipment	397	5.05%
Micellaneous Equipment	398	2.67%

Note: Per the Settlement in Docket No. ER10-355, Appendix A.1.2, AEP APPALACHIAN TRANSMISSION COMPANY shall use the depreciation rates shown above by FERC Account until such time as the FERC approves new depreciation rates pusuant to a Section 205 or 206 filing to change rates.

APCo Transco Depreciation Rates are based on the APCo VA Order in VA SCC Case No. PUR-2020-00015.

<u>Composite Depreciation Rate</u> <u>OpCo Company</u> <u>OpCo Company</u> <u>TOTAL</u>

- 1 T-Plant (FF1 206.58.g)
- 2 T-Plant (FF1 206.58.b)
- 3 Average (Ln 1+ Ln 2)/2
- 4 Depreciation (FF1 336.7.f)
- 5 Composite Depreciation (Ln 3 / Ln 4)

Note: AEP APPALACHIAN TRANSMISSION COMPANY shall initially use the composite depreciation rate for Virginia and West Virginia shown above to estimate depreciation expense for transmission projects in Worksheets J and K until a composite depreciation rate based on transmission plant in service and depreciation expenses recorded by AEP APPALACHIAN TRANSMISSION COMPANY for its own transmission facilities can be calculated in AEP APPALACHIAN TRANSMISSION COMPANY's the first Annual Update including a True-Up TCOS.

AEPTCo subsidiaries in PJM Worksheet - P DEPRECIATION RATES FOR TRANSMISSION PLANT PROPERTY ACCOUNTS EFFECTIVE AS OF 3/11/2020

AEP INDIANA MICHIGAN TRANSMISSION COMPANY

TRANSMISSION PLANT	PLANT ACCT.	RATES Note 1
Land Rights	350.1	1.66%
Structures & Improvements	352.0	1.77%
Station Equipment	353.0	2.43%
Towers & Fixtures	354.0	2.57%
Poles & Fixtures	355.0	3.19%
Overhead Conductor	356.0	2.35%
Underground Conduit	357.0	2.30%
Underground Conductors	358.0	1.93%
GENERAL PLANT		
Structures and Improvements	390	2.08%
Office Furniture and Equip.	391	4.79%
Stores Equipment	393	7.35%
Tools, Shop and Garage Equipment	394	6.99%
Laboratory Equipment	395	5.41%
Power Operated Equipment	396	4.81%
Communications Equipment	397	3.91%
Micellaneous Equipment	398	3.32%

Note: Per the Settlement in Docket No. ER10-355, Appendix A.1.2, AEP INDIANA MICHIGAN TRANSMISSION COMPANY shall use the depreciation rates shown above by FERC Account until such time as the FERC approves new depreciation rates pusuant to a Section 205 or 206 filing to change rates.

Composite Depreciation Rate	OpCo Company	OpCo Company	<u>TOTAL</u>
T-Plant (FF1 206.58.g)			
T-Plant (FF1 206.58.b)			
Average (Ln 1+ Ln 2)/2			
Depreciation (FF1 336.7.f)			
Composite Depreciation (Ln 3 / Ln 4)			

Note: Rates approved in Indiana Cause No. 45235 effective March 11, 2020.

AEPTCo subsidiaries in PJM Worksheet - P DEPRECIATION RATES FOR TRANSMISSION PLANT PROPERTY ACCOUNTS EFFECTIVE AS OF 1/1/2020

AEP OHIO TRANSMISSION COMPANY

	PLANT ACCT.	RATES Note 1
TRANSMISSION PLANT		
Land Rights	350.1	1.03%
Energy Storage Equipment	351.0	14.22%
Structures & Improvements	352.0	1.95%
Station Equipment	353.0	2.43%
Towers & Fixtures	354.0	2.27%
Poles & Fixtures	355.0	3.53%
Overhead Conductor	356.0	2.30%
Underground Conduit	357.0	2.59%
Underground Conductors	358.0	3.09%
GENERAL PLANT		
Structures & Improvements	390.0	2.65%
Office Furniture & Equipment	391.0	3.73%
Stores Equipment	393.0	4.43%
Tools Shop & Garage Equipment	394.0	4.59%
Laboratory Equipment	395.0	5.01%
Power Operated Equipment	396.0	4.71%
Communication Equipment	397.0	4.87%
Miscellaneous Equipment	398.0	4.24%

Note: Per the Settlement in Docket No. ER10-355, Appendix A.1.2, AEP OHIO TRANSMISSION COMPANY shall use the depreciation rates shown above by FERC Account until such time as the FERC approves new depreciation rates pusuant to a Section 205 or 206 filing to change rates.

APCo Transco Depreciation Rates are based on the APCo VA Order in VA SCC Case No. PUR-2020-00015.

Composite Depreciation Rate	OpCo Company	OpCo Company	TOTAL
T-Plant (FF1 206.58.g)			
T-Plant (FF1 206.58.b)			
Average (Ln 1+ Ln 2)/2			
Depreciation (FF1 336.7.f)			
Composite Depreciation (Ln 3 / Ln 4)			

Note: AEP OHIO TRANSMISSION COMPANY shall initially use the composite depreciation rate for APCo, I&M and KPCo shown above to estimate depreciation expense for transmission projects in Worksheets J and K until a composite depreciation rate based on transmission plant in service and depreciation expenses recorded by AEP OHIO TRANSMISSION COMPANY for its own transmission facilities can be calculated in AEP OHIO TRANSMISSION COMPANY's the first Annual Update including a True-Up TCOS.

AEPTCo subsidiaries in PJM Worksheet - P DEPRECIATION RATES FOR TRANSMISSION PLANT PROPERTY ACCOUNTS EFFECTIVE AS OF 1/1/2020

AEP WEST VIRGINIA TRANSMISSION COMPANY

TRANSMISSION PLANT	PLANT ACCT.	RATES Note 1
Energy Storage Equipment	351.0	14.22%
Structures & Improvements	352.0	1.99%
Station Equipment Towers & Fixtures	353.0 354.0	2.70% 1.64%
Poles & Fixtures	355.0	3.46%
Overhead Conductor	356.0	1.65%
Underground Conduit	357.0	2.49%
Underground Conductors	358.0	4.72%
GENERAL PLANT		
Structures & Improvements	390.0	1.89%
Office Furniture & Equipment	391.0	3.21%
Transportation Equipment	392.0	3.46%
Stores Equipment	393.0	1.78%
Tools Shop & Garage Equipment	394.0	2.59%
Laboratory Equipment	395.0	3.87%
Power Operated Equipment	396.0	3.90%
Communication Equipment	397.0	5.05%
Miscellaneous Equipment	398.0	2.67%

Note: Per the Settlement in Docket No. ER10-355, Appendix A.1.2, AEP WEST VIRGINIA TRANSMISSION COMPANY shall use the depreciation rates shown above by FERC Account until such time as the FERC approves new depreciation rates pusuant to a Section 205 or 206 filing to change rates.

APCo Transco Depreciation Rates are based on the APCo VA Order in VA SCC Case No. PUR-2020-00015.

	Composite Depreciation Rate	OpCo Company	OpCo Company	<u>TOTAL</u>
1	T-Plant (FF1 206.58.g)			
2	T-Plant (FF1 206.58.b)			
3	Average (Ln 1+ Ln 2)/2			
4	Depreciation (FF1 336.7.f)			
5	Composite Depreciation (Ln 3 / Ln 4)			

Note: AEP WEST VIRGINIA TRANSMISSION COMPANY shall initially use the composite depreciation rate for APCo and WPCo shown above to estimate depreciation expense for transmission projects in Worksheets J and K until a composite depreciation rate based on transmission plant in service and depreciation expenses recorded by AEP WEST VIRGINIA TRANSMISSION COMPANY for its own transmission facilities can be calculated in AEP WEST VIRGINIA TRANSMISSION COMPANY's the first Annual Update including a True-Up TCOS.

AEP East Consolidated Utility Capital Structure Consolidation of Operating Companies' Capital Structure @ 12-31-Worksheet Q Page 1

Worksheet Q Page 1								
								AEP East Operating
Lina		Appalachian Power	Indiana Michigan Power	Kentucky Power	Kingsport Power	Ohio Power	Wheeling Power	Companies' Consolidated Capital
Line Develo	pment of Long Term Debt Balances at Year End	Company	Company	Company	Company	Company	Company	Structure
1	Bonds (112.18.c&d)							
2 3	Less: Reacquired Bonds (112.19.c&d) LT Advances from Assoc. Companies (112.20.c&d)							
4	Senior Unsecured Notes (112.21.c&d) Excludes Spent Nuc Fuel Disp Fund							
5 6	Less: Fair Value Hedges (See Note on Ln 7 below) Total Long Term Debt Balance							-
7	NOTE: The balance of fair value hedges on outstanding long term debt are t FF1)	o be excluded from the	balance of long	term debt includ	ed in the formul	a's capital struc	ture. (page 257,	Column H of the
	pment of Long Term Debt Interest Expense							
8 9	Interest on Long Term Debt (256-257.33.i) Amort of Debt Discount & Expense (117.63.c)							
10	Amort of Loss on Reacquired Debt (117.64.c)							
11 12	Less: Amort of Premium on Debt (117.65.c)							
13	Less: Amort of Gain on Reacquired Debt (117.66.c) Less: Hedge Interest on pp 256-257(i)							
14	LTD Interest Expense							
Develo 15	pment of Cost of Preferred Stock and Preferred Dividends Dividend Rate (p. 250-251. 7.a)							
16	Par Value (p. 250-251. 8.c)							
17	Shares Outstanding (p.250-251. 8.e)							
18 19	Monetary Value (Ln 16 * Ln 17) Dividend Amount (Ln 15 * Ln 18)							
20	Dividend Rate (p. 250-251. 7.a)							
21	Par Value (p. 250-251. 8.c)							
22 23	Shares Outstanding (p.250-251. 8.e) Monetary Value (Ln 21 * Ln 22)							
24	Dividend Amount (Ln 20 * Ln 23)							
25	Dividend Rate (p. 250-251. 7.a)							
26 27	Par Value (p. 250-251. 8.c) Shares Outstanding (p.250-251. 8.e)							
28	Monetary Value (Ln 26 * Ln 27)							
29	Dividend Amount (Ln 25 * Ln 28)							
30 31	Dividend Rate (p. 250-251. 7.a) Par Value (p. 250-251. 8.c)							
32	Shares Outstanding (p.250-251. 8.e)							
33	Monetary Value (Ln 31 * Ln 32)							
34 35	Dividend Amount (Ln 30 * Ln 33) Preferred Stock (Lns 18, 23, 28,33)							
36	Preferred Dividends (Lns 19, 24, 29,34)							
Develo 37	Promistory Carital (112.16 a)							
38	Proprietary Capital (112.16.c) Less: Preferred Stock (Ln 35 Above)							
39	Less: Account 216.1 (112.12.c)							
40	Less: Account 219.1 (112.15.c)							
41 Calcul	Balance of Common Equity ation of Capital Shares							
42	Long Term Debt (Ln 6 Above)							
43 44	Preferred Stock (Ln 35 Above) Common Equity (Ln 41 Above)							
45	Total Company Structure							
46	LTD Capital Shares (Ln 42 / Ln 45)							
47 48	Preferred Stock Capital Shares (Ln 43 / Ln 45) Common Equity Capital Shares (Ln 44 / Ln 45)							
49	RESERVED							
50	Reserved							
51 52	Reserved Reserved							
	ation of Capital Cost Rate							
53	LTD Capital Cost Rate (Ln 14 / Ln 6)							
54 55	Preferred Stock Capital Cost Rate (Ln 36 / Ln 35) Common Equity Capital Cost Rate	11.49%	11.49%	11.49%	11.49%	11.49%	11.49%	11.49%
	ation of Weighted Capital Cost Rate	11.7//0	11.77/0	11.7/0	11.7//0	11.77/0	11.77/0	11.77/0
56	LTD Weighted Capital Cost Rate (Ln 46 * Ln 53)							
57 58	Preferred Stock Capital Cost Rate (Ln 47 * Ln 54) Common Equity Capital Cost Rate (Ln 48 * Ln 55)							
59	Total Company Structure							

AEP East Consolidated Utility Capital Structure Consolidation of Operating Companies' Capital Structure @ 12-31-___ Worksheet Q Page 2

Calculation of Weighted Capital Cost Rate 115 LTD Weighted Capital Cost Rate (Ln 105 * Ln 112) 116 Preferred Stock Capital Cost Rate (Ln 106 * Ln 113)	wer ed Capita	Wheeling Power Company	Ohio Power Company	Kingspo rt Power Compan y	Kentucky Power Company	Indiana Michigan Power Company	Appalachi an Power Company		Line
61 Lase Recognized Bonde (112.19.c&d) 5				•			* *		
California Cal									
Senior Unsecured Notes (11.21, e&d) Excludes Speat Nise Fuel Disp 6 Less: Fair Value Hedges (See Note on Ln 66 below) 6 Less: Fair Value Hedges (See Note on Ln 66 below) 6 Total Long Term Debt Balance 6 Total Long Term Debt Balance 7 Total Person Debt (256-2573.3.) 8 Amend To Beth Decoural & Expanse (11.62.) 9 Amend To Beth Decoural & Expanse (11.62.) 9 Less: Annot of Fornium on Debt (117.65.) 1 Less: Annot of Fornium on Debt (117.65.) 1 Less: Hedge Interest on pp. 256-257() 1 Less: Hedge Interest on pp. 256-257() 1 Less: Annot of Gian on Resequine Debt (117.66.) 2 Less: Hedge Interest on pp. 256-257() 3 LTD Interest Expanse 8 Devolution (11.62.) 1 Less: Annot of Fornium on Debt (117.65.) 2 Less: Hedge Interest on pp. 256-257() 3 LTD Interest Expanse 8 Devolution (11.62.) 3 LTD Interest Expanse 8 Devolution (11.62.) 3 LTD Interest Expanse 8 Devolution (11.62.) 4 Devidend Annount (1.74 Ln.77) 5 Dividend Annount (1.74 Ln.77) 5 Dividend Annount (1.79 Ln.83.) 5 Dividend Annount (1.79 Ln.83.) 6 Mootarty Value (p. 250-251. 8.) 7 Dividend Annount (1.79 Ln.83.) 7 Dividend Annount (1.79 Ln.83.) 7 Dividend Annount (1.79 Ln.83.) 8 Dividend Annount (1.79 Ln.83.) 9 Dividend Annount (1.70 Ln.94.) 9 Less Account (1.70 Ln.94.) 9 Less Account (1.70 Ln.94.) 10 Long Expanse (1.70 Ln.94.) 11 Long Expanse (1.70 Ln.94									
Common C									
See: Fair Value Hedges (See Note on In 66 below)									
NOTIE: The balance of fair value hedges on outstanding long term debt are to be excluded from the balance of long term debt included in the formula's capital structure. (p. 257, Col Breedsparent of Long Term Debt (195-257, Sa.)) Provided from the Provided (195-257, Sa.)) Amort of Loss on Resequired Debt (117-64c) Less: Amort of Fremium on Debt (117-65c) Less: Amort of Fremium on Debt (117-65c) Less: Amort of Gain on Resequired Debt (117-65c) Less: Hong femerat on pp 25c-257(i) July 10 Interest Expense Providency (p. 20-251, Re.) Nonchary Value (1.07 % Los.) Providency (p. 20-251, Re.) Providency (p. 20-251,									
66 Development of Long Term Debt (125-62-571-33) 67 Interest on Long Term Debt (125-62-571-33) 68 Annor of Deb Discount & Expense (117-53-6) 70 Less Annor of Premium on Debt (117-65-6) 71 Less Annor of Gian on Recupierd Debt (117-66-6) 72 Less Hodge Interest on pp 25-62-57(6) 73 LTD Interest Expense Development of Cost of Preferred Stock and Preferred Dividends 74 Dividend Rate (1, 250-251-18-6) 75 Par Value (p, 250-251-8-6) 76 Dividend Amount (Ln 74 * Ln 77) 77 Dividend Rate (p, 250-251-8-6) 78 Dividend Amount (Ln 74 * Ln 77) 79 Dividend Amount (Ln 74 * Ln 77) 70 Dividend Rate (p, 250-251-8-6) 71 Shares Cottainding (p, 250-251-8-6) 72 Annotation of London (Ln 75 * Ln 83) 73 Par Value (p, 250-251-8-6) 74 Dividend Rate (p, 250-251-8-6) 75 Dividend Rate (p, 250-251-8-6) 76 Dividend Rate (p, 250-251-8-6) 77 Dividend Rate (p, 250-251-8-6) 78 Dividend Amount (Ln 74 * Ln 77) 79 Dividend Rate (p, 250-251-8-6) 70 Dividend Rate (p, 250-251-8-6) 71 Dividend Rate (p, 250-251-8-6) 72 Dividend Rate (p, 250-251-8-6) 73 Dividend Rate (p, 250-251-8-6) 74 Dividend Rate (p, 250-251-8-6) 75 Dividend Rate (p, 250-251-8-6) 75 Dividend Rate (p, 250-251-8-6) 75 Dividend Rate (p, 250-251-8-6) 76 Dividend Rate (p, 250-251-8-6) 77 Dividend Rate (p, 250-251-8-6) 78 Dividend Rate (p, 250-251-8-6) 79 Dividend Rate (p, 250-251-8-6) 70 Dividend Rate (p, 250-251-8-6) 70 Dividend Rate (p, 250-251-8-6) 71 Dividend Rate (p, 250-251-8-6) 72 Dividend Rate (p, 250-251-8-6) 73 Dividend Rate (p, 250-251-8-6) 74 Dividend Rate (p, 250-251-8-6) 75 Dividend Rate (p, 250-251-8-6) 75 Dividend Rate (p, 250-251-8-6) 75 Dividend Rate (p, 250-251-8-6) 76 Dividend Rate (p, 250-251-8-6) 77 Dividend Rate (p, 250-251-8-6) 78 Dividend Rate (p, 250-251-8-6) 79 Dividend Rate (p, 250-251-8-6) 70 Dividend Rate (p, 250-251-8-6) 70 Dividend Rate (p, 250-251-8-6) 70 Dividend Rate (p, 250-251-8-6) 71 Dividend Rate (p, 250-251-8-6) 72 Dividend Rate (p, 250-251-8-6) 73 Dividend Rate (p, 250-251-8-6) 74 Dividend Rate (p, 250-251-8-6) 75 Dividend Rate (p, 250-251-8-6) 75 Divi								Total Long Term Debt Balance	65
Development of Long Term Debt (1962-62-733-3)	olumn H of the FF1)	. 257, Column	al structure. (p.	formula's capi	included in the	long term debt	to be excluded from the balance	NOTE: The balance of fair value hedges on outstanding long term debt ar	
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70 Less: Amort of Premium on Debt (117.65.c) 71 Less: Hodge Interest to gain of Receptive Debt (117.65.c) 72 Less: Hodge Interest on pp 256-257(i) 73 LITD Interest Expense **Development of Cost of Preferred Stock and Preferred Dividends** 74 Dividend Rate (p. 250-251, 7.a) 75 Shares Outstanding (p.250-251, 8.c) 76 Shares Outstanding (p.250-251, 8.c) 77 Monetary Value (Ln 78 * Ln 76) 78 Dividend Amount (Ln 78 * Ln 76) 79 Dividend Rate (p. 250-251, 8.c) 80 Par Value (p. 250-251, 8.c) 81 Shares Outstanding (p. 250-251, 8.c) 82 Monetary Value (Ln 80 * Ln 81) 83 Dividend Rate (p. 250-251, 8.c) 84 Dividend Rate (p. 250-251, 8.c) 85 Par Value (p. 250-251, 8.c) 85 Par Value (p. 250-251, 8.c) 86 Shares Outstanding (p. 250-251, 8.c) 87 Monetary Value (Ln 85 * Ln 86) 88 Dividend Amount (Ln 84 * Ln 87) 89 Dividend Rate (p. 250-251, 8.c) 80 Par Value (p. 250-251, 8.c) 81 Dividend Manount (Ln 84 * Ln 87) 80 Dividend Manount (Ln 84 * Ln 87) 81 Dividend Manount (Ln 84 * Ln 87) 82 Dividend Manount (Ln 84 * Ln 87) 83 Dividend Manount (Ln 84 * Ln 87) 84 Dividend Manount (Ln 84 * Ln 87) 85 Dividend Manount (Ln 84 * Ln 87) 86 Par Value (p. 250-251, 8.c) 87 Monetary Value (Ln 90 * Ln 91) 88 Dividend Manount (Ln 84 * Ln 87) 89 Dividend Manount (Ln 84 * Ln 87) 80 Dividend Manount (Ln 84 * Ln 87) 80 Dividend Manount (Ln 84 * Ln 87) 80 Dividend Manount (Ln 84 * Ln 87) 81 Dividend Manount (Ln 84 * Ln 87) 82 Dividend Manount (Ln 84 * Ln 87) 83 Dividend Manount (Ln 84 * Ln 87) 84 Dividend Manount (Ln 84 * Ln 87) 85 Dividend Manount (Ln 84 * Ln 87) 86 Par Value (Ln 87, 82, 87, 92) 87 Preferred Stock (Ln 87, 82, 87, 92) 89 Preferred Stock (Ln 87, 82, 87, 92) 80 Preferred Stock (Ln 80 * Ln 112) 80 Preferred Stock (Ln 81 State (Ln 187 Ln 164) 81 Dividend Manount (Ln 84 * Ln 87) 81 Dividend Manount (Ln 84 * Ln 87) 82 Dividend Manount (Ln 84 * Ln 87) 83 Dividend Manount (Ln 84 * Ln 87) 84 Dividend Manount (Ln 84 * Ln 87) 85 Dividend Manount (Ln 84 * Ln 87) 86 Dividend Manount (Ln 84 * Ln 87)									
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73 LTD Interest Expense Previoument of Cost of Preferred Stock and Preferred Dividends 74 Dividend Rate (p. 230-231, Ra) 75 Par Value (p. 230-231, Ra) 76 Shares Outstanding (p.250-231, Ra) 77 Monetary Value (Ln 74 * Ln 76) 78 Dividend Amount (Ln 74 * Ln 77) 79 Dividend Amount (Ln 74 * Ln 77) 79 Dividend Rate (p. 230-231, Ra) 80 Par Value (p. 230-231, Ra) 81 Shares Outstanding (p.250-231, Ra) 82 Monetary Value (Ln 78 * Ln 81) 83 Dividend Rate (p. 230-231, Ra) 84 Dividend Rate (p. 230-231, Ra) 85 Par Value (p. 230-231, Ra) 85 Par Value (p. 230-231, Ra) 85 Par Value (p. 230-231, Ra) 86 Shares Outstanding (p.250-231, Ra) 87 Monetary Value (Ln 88 * Ln 86) 88 Dividend Annount (Ln 88 * Ln 86) 89 Dividend Rate (p. 230-231, Ra) 90 Par Value (p. 230-231, Ra) 91 Par Value (p. 230-231, Ra) 92 Monetary Value (Ln 89 * Ln 89) 93 Dividend Annount (Ln 88 * Ln 80) 94 Preferred Bividends (Ln 78, 83, 88, 93) Prevention of Common Equity (Ln 104) 95 Evolution of Common Equity (Ln 104) 96 Ropertary Capital (Ln 49 Above) 101 Long Term Debt (Ln 65 Above) 102 Preferred Stock (Ln 73 Ln 65) 104 Long Term Debt (Ln 65 Above) 105 Preferred Stock (Ln 73 Ln 65) 106 Ralance of Common Equity (Ln 104) 107 Common Equity Capital Shares (Ln 107 / Ln 104) 108 RESERVED 109 RESERVED 110 RESERVED 110 Long Term Debt (Ln 65 Rate (Ln 73 / Ln 65) 111 Preferred Stock (Ln 73 Ln 65) 112 LTD Capital Shares (Ln 107 / Ln 104) 113 Preferred Stock (Ln 73 Ln 65) 114 Preferred Stock (Ln 73 Ln 65) 115 Preferred Stock (Ln 71 Ln 104) 116 Preferred Stock (Ln 71 Ln 105 / Ln 113)									
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Shares Outstanding (p.250-251, Re)									
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Dividend Amount (Ln 89 * Ln 92) Preferred Stock (Lns 77, 82, 87, 92) Preferred Dividends (Lns 78, 83, 88, 93)									
94 Preferred Stock (Lns 77, 82, 87,92) 95 Preferred Dividends (Lns 78, 83, 88,93) Prevelopment of Common Equity 96 Proprietary Capital (112.16.c) 97 Less: Account 216.1 (112.16.c) 98 Less: Account 219.1 (112.15.c) 100 Balance of Common Equity Calculation of Capital Shares 101 Long Term Debt (Ln 65 Above) 102 Preferred Stock (Ln 94 Above) 103 Common Equity (Ln 100 Above) 104 Total Company Structure 105 LTD Capital Shares (Ln 101 / Ln 104) 106 Preferred Stock Capital Shares (Ln 102 / Ln 104) 107 Common Equity (La 100 Above) 109 RESERVED 110 RESERVED 111 RESERVED 111 RESERVED 112 LTD Capital Cost Rate (Ln 73 / Ln 65) 113 Preferred Stock Capital Cost Rate (Ln 95 / Ln 94) 114 Common Equity (La 100 Above) 115 LTD Capital Shares (Ln 103 / Ln 104) 116 Preferred Stock Capital Cost Rate (Ln 105 * Ln 112) 117 Capital Cost Rate (Ln 95 / Ln 94) 118 Preferred Stock Capital Cost Rate (Ln 105 * Ln 112) 119 Preferred Stock Capital Cost Rate (Ln 105 * Ln 112) 110 Preferred Stock Capital Cost Rate (Ln 105 * Ln 112) 111 Preferred Stock Capital Cost Rate (Ln 105 * Ln 112) 112 Preferred Stock Capital Cost Rate (Ln 105 * Ln 112)									
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Calculation of Capital Shares 101 Long Term Debt (Ln 65 Above)								, ,	
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103									
103									
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107 Common Equity Capital Shares (Ln 103 / Ln 104)									105
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109 RESERVED 110 RESERVED 111 RESERVED 112 RESERVED 113 RESERVED 114 RESERVED 115 RESERVED 115 RESERVED 116 RESERVED 117 RESERVED 118 RESERVED 119 RESERVED 119 RESERVED 110									
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Calculation of Capital Cost Rate									
112									
113 Preferred Stock Capital Cost Rate (Ln 95 / Ln 94) 114 Common Equity Capital Cost Rate 11.49%									
114 Common Equity Capital Cost Rate 11.49%								Preferred Stock Capital Cost Rate (Ln 95 / Ln 94)	
115 LTD Weighted Capital Cost Rate (Ln 105 * Ln 112) 116 Preferred Stock Capital Cost Rate (Ln 106 * Ln 113)	9% 11.49	11.49%	11.49%	11.49%	11.49%	11.49%	11.49% 11.49%	Common Equity Capital Cost Rate	
116 Preferred Stock Capital Cost Rate (Ln 106 * Ln 113)									
117 Common Equity Capital Cost Rate (Ln 107 * Ln 114)									
117 Common Equity Capital Cost Rate (Ln 107 * Ln 114) 118 Total Company Structure									
110 Ional Company Structure								Total Company Structure	110

AEP East

AEP East Consolidated Utility Capital Structure Consolidation of Operating Companies' Average Capital Structure Worksheet Q Page 3

			Indiana		Ohio		Operating Companies'
		Appalachi	Michigan	Kingsport	Power	Wheeling	Companies
		an Power	Power	Power	Compan	Power	Capital
Line		Company	Company	Company	y	Company	Structure
Develop	ment of Average Long Term Debt						
119	Average Bonds (Ln 1 + Ln 60) / 2						
120	Less: Average Reacquired Bonds (Ln 2 + Ln 61) / 2 Average LT Advances from Assoc. Companies (Ln 3 + Ln 62) /						
121	2						
122	Average Senior Unsecured Notes (Ln 4 + Ln 63) / 2						
123	Less: Average Fair Value Hedges (See Note on Ln 125 below)						
124	Average Balance of Long Term Debt						
	NOTE: The balance of fair value hedges on outstanding long term	debt are to be excluded from the	e balance of long term	debt included in the formula's	capital structu	ire. (p. 257, Co	lumn H of the
125	FF1)					d	
Develop	ment of Long Term Debt Interest Expense						
126	Interest on Long Term Debt (256-257.33.i)						
127	Amort of Debt Discount & Expense (117.63.c)						
128	Amort of Loss on Reacquired Debt (117.64.c)						
129	Less: Amort of Premium on Debt (117.65.c)						
130	Less: Amort of Gain on Reacquired Debt (117.66.c)						
131	Less: Hedge Interest on pp 256-257(i)						
132	LTD Interest Expense						
	Preferred Stock and Preferred Dividends						
133	Average Balance of Preferred Stock (Ln 35 + Ln 94) / 2						
134	Preferred Dividends (Ln 36)						
	ment of Average Common Equity						
135	Average Proprietary Capital (Ln 37 + Ln 96) / 2						
136	Less: Average Preferred Stock (Ln 133 Above)						
137	Less: Average Account 216.1 (Ln 39 + Ln 98) / 2						
138	Less: Average Account 219.1 (Ln 40 + Ln 99) / 2						
139	Average Balance of Common Equity						
	ion of Capital Shares						
140	Average Balance of Long Term Debt (Ln 124 Above)						
141	Average Balance of Preferred Stock (Ln 133 Above)						
142	Average Balance of Common Equity (Ln 139 Above)						
143	Average of Total Company Structure						
144	Average Balance of LTD Capital Shares (Ln 140 / Ln 143)						
1.45	Average Balance of Preferred Stock Capital Shares (Ln 141 / Ln						
145	143) Average Balance of Common Equity Capital Shares (Ln 142 /						
146	Ln 143)						
146	Reserved						
148	Reserved						
149	Reserved						
150	Reserved						
	ion of Capital Cost Rate						
151	LTD Capital Cost Rate (Ln 132 / Ln 124)						
152	Preferred Stock Capital Cost Rate (Ln 134 / Ln 133)						
153	Common Equity Capital Cost Rate	11.49%	11.49%	11.49% 11.49%	11.49%	11.49%	11.49%
	ion of Weighted Capital Cost Rate						
154	LTD Weighted Capital Cost Rate (Ln 144 * Ln 151)						
155	Preferred Stock Capital Cost Rate (Ln 145 * Ln 152)						
156	Common Equity Capital Cost Rate (Ln 146 * Ln 153)						
157	ACTUAL WEIGHTED AVG COST OF CAPITAL						-

AEP East

AEPTCo subsidiaries in PJM Cost of Service Formula Rate Using Actual/Projected FF1 Balances Worksheet R – True-up With Interest (Hypothetical Example)

Reconciliation Revenue Requirement For Year 2018 Available May 25, 2019

2018 Revenue Requirement Forecast by October 31, 2017 True-up Adjustment -Over (Under) Recovery

Leavest Date on Assessed of	Defende on	Over (Under) Recovery Plus Interest	Average Monthly Interest Rate	Months	Calculated Interest	Amortizatio n	Surcharge (Refund) Owed
Interest Rate on Amount of							
An over or under collection	will be reco	vered prorata over 2018,	, held for 2019 and	returned pr	orata over 2020		
Calculation of Interest					Monthly		
	Year	-		-			-
January	2018		0.2780%	12			
T-1	Year	-	0.0000	-			-
February	2018		0.2780%	11			
March	Year 2018	-	0.2780%	10			-
Water	Year	_	0.270070	-			_
April	2018		0.2780%	9			
•	Year	-		-			-
May	2018		0.2780%	8			
*	Year	-	0.27000/	-			-
June	2018 Year	_	0.2780%	7			
July	2018	-	0.2780%	6			-
0 41.5	Year	-	0.270070	-			-
August	2018		0.2780%	5			
	Year	-		-			-
September	2018		0.2780%	4			
October	Year 2018	-	0.2780%	3			-
Octobel	Year	-	0.278070	<i>3</i>			_
November	2018		0.2780%	2			
	Year	-		-			-
December	2018		0.2780%	1		-	
					-		-
					Annual		
	Year				Annuai		
January through December	2019	-	0.2780%	12	-		-
, .							
Over (Under) Recovery Plus	s Interest Ar	nortized and Recovered					
Over 12 Months	s interest Ar	noi tizeu anu Necovei eu			Monthly		
<u></u>	Year	-		-		-	_
January	2020		0.2780%				
	Year	-		-		-	-
February	2020		0.2780%				
March	Year 2020	-	0.2780%	-		-	-
14141011	Year	-	0.270070	-		-	_
April	2020		0.2780%				
	Year	-		-		-	-
May	2020		0.2780%				
Tours	Year	-	0.27909/	-		-	-
June	2020	_	0.2780%			_	_
July	Year		0.2780%	-			

	2020				
	Year	-		_	
August	2020		0.2780%		
_	Year	-		-	
September	2020		0.2780%		
	Year	-		-	
October	2020		0.2780%		
	Year	-		-	
November	2020		0.2780%		
	Year	-		-	
December	2020		0.2780%		_
				-	
True-Up Adjustment with					-
Interest					
Less Over (Under)					-
Recovery					
T (1)					-
Total Interest					

Note 1: The interest rate to be applied to the over recovery or under recovery amounts will be determined using the average monthly FERC interest rate (as determined pursuant to 18 C.F.R. Section 35.19a) for the twenty (20) months from the beginning of the rate year being trued-up through August 31 of the following year.

Attachment A

Revised Calculations of the AEP East Companies Annual Update with KPCo's Revenue Requirement Removed

AEP EAST Companies Transmission Formula Rate Revenue Requirement Forecasted Costs Through December 31, 2022 For rates effective January 1, 2022

AEP Zone Transmission Service Revenue Requirement AEP Annual

AEP Annual

APCo Annual

I&M Annual

KPCo Annual

AEP Annual

Line No.			Revenue Requirement	Revenue Requirement w/ KPCO	Revenue Difference	Revenue Requirement	Revenue Requirement	Revenue Requirement	Revenue Requirement	Revenue Requirement	Revenue Requirement
A. Netwo	ork Service										
1	REVENUE REQUIREMENT (w/o incentives)	(TCOS Ln 1)	\$1,044,254,829	\$1,127,299,593	\$83,044,764	\$457,333,005	\$179,464,475		\$6,334,869	\$386,169,085	\$14,953,395
2	LESS: REVENUE CREDITS	(TCOS Ln 2)	\$28,503,000	\$28,867,000	\$364,000	\$6,252,000	\$4,410,000		\$165,000	\$13,218,000	\$4,458,000
3	CURRENT YEAR ZONE 1 AEP NETWORK SERVICE REVENUE REQUIREMENT	(TCOS Ln 3)	\$1,015,751,829	\$1,098,432,593	\$82,680,764	\$451,081,005	\$175,054,475		\$6,169,869	\$372,951,085	\$10,495,395
4 5 6 7	LESS: REVENUE REQUIREMENTS INCLUDED IN LINE 1 FOR: RTEP UPGRADES (W/O INCENTIVES) OTHER ZONAL UPGRADES (W/O INCENTIVES) SUBTOTAL	(TCOS Ln 5) (Worksheet J)	\$41,500,452 \$0 \$41,500,452	\$41,500,452 \$0 \$41,500,452	\$0 \$0 \$0	\$26,695,952 \$0 \$26,695,952	\$5,322,411 <u>\$0</u> \$5,322,411		\$0 \$0 \$0	\$9,365,691 \$0 \$9,365,691	\$116,397 \$0 \$116,397
,											
8	EXISTING ZONAL ATRR (W/O INCENTIVES)	(Ln 3- Ln 7)	\$974,251,377	\$1,056,932,141	\$82,680,764	\$424,385,052	\$169,732,064		\$6,169,869	\$363,585,394	\$10,378,998
9	INCENTIVE REVENUE REQUIREMENT FOR ZONAL PROJECTS	(Worksheet J)	\$0	\$0	\$0	\$0	\$0		\$0	\$0	\$0
10	EXISTING ZONAL ATRR (W/ INCENTIVES)	(Ln 8 + Ln 9)	\$974,251,377	\$1,056,932,141	\$82,680,764	\$424,385,052	\$169,732,064		\$6,169,869	\$363,585,394	\$10,378,998
11	PRIOR YEAR TRUE-UP (2020 including interest)	(Worksheet Q)	\$49,930,588	\$52,794,055	\$2,863,467	\$7,949,401	\$6,143,376		(\$901,487)	\$36,311,544	\$427,754
11a	Facility Credits under PJM OATT Section 30.9	(TCOS Ln 3)	\$6,097,445	\$6,097,445	\$0					\$6,097,445	
11b	Adjusments from prior Annual Updates		-\$3,001,200	-\$3,022,450	-\$21,250					-\$3,001,200	
12	EXISTING ZONAL PTRR FOR PJM OATT	(Ln 10 + Ln 11)	\$1,027,278,210	\$1,112,801,191	\$85,522,982	\$432,334,453	\$175,875,440	\$0	\$5,268,382	\$402,993,183	\$10,806,752
B Point	-to-Point Service										
13	2022 AEP East Zone Network Service Peak Load (1 CP)		21,925.3	21,925.3	- M	IW					
14 15 16 17 18 19 20	Annual Point-to-Point Rate in \$/MW - Year Monthly Point-to-Point Rate in \$/MW - Month Weekly Point-to-Point Rate in \$/MW - Weekly Daily On-Peak Point-to-Point Rate in \$/MW - Day Daily Off-Peak Point-to-Point Rate in \$/MW - Day Hourly On-Peak Point-to-Point Rate in \$/MW - Hour Hourly On-Peak Point-to-Point Rate in \$/MW - Hour Hourly Off-Peak Point-to-Point Rate in \$/MW - Hour	(Ln 12 / Ln 13) (Ln 14 / 12) (Ln 14 / 52) (Ln 14 / 260) (Ln 14 / 365) (Ln 14 / 4160) (Ln 14 / 8760)	\$46,853.55 \$3,904.46 \$901.03 \$180.21 \$128.37 \$11.26 \$5.35	\$50,754.21 \$4,229.52 \$976.04 \$195.21 \$139.05 \$12.20 \$5.79	\$3,900.65 \$325.05 \$75.01 \$15.00 \$10.69 \$0.94						
21	RTEP UPGRADE ATRR W/O INCENTIVES	(Ln 7)	41,500,452	41,500,452	-	26,695,952	5,322,411		-	9,365,691	116,397
22 23	ADDITIONAL ATRR FOR FERC-APPROVED INCENTIVES ON RTEP TRUE-UP ADJUSTMENT INCLUDING INTEREST	(Worksheet J) (Worksheet Q)	6.432.945	6.432.945	-	5.263.827	470,168		-	697.095	1,855
24	RTEP PTRR FOR PJM COLLECTION UNDER SCHEDULE 12	(\$ 47,933,397		-	31,959,779	5,792,580			10,062,786	118,252

KNG Annual

OPCo Annual WPCo Annual

AEP EAST Companies Transmission Formula Rate Revenue Requirement Utilizing Projected or FERC Form 1 Data For rates effective January 1, 2021

AEP Transmission Schedule 1A Revenue Requirements

Line No.			AEP Annual Revenue Requirement	APCo Annual Revenue Requirement	I&M Annual Revenue Requirement	KPCo Annual Revenue Requirement	KNG Annual Revenue Requirement	OPCo Annual Revenue Requirement	WPCo Annual Revenue Requirement
A. Sched	dule 1A ARR								
1	Total Load Dispatch & Scheduling (Account 561) (TCOS Line	15)	\$21,972,000	\$10,331,000	\$7,152,000	\$1,957,000	\$9,000	\$1,156,000	\$1,367,000
2	Less: Load Disptach - Scheduling, System Control and Dispat		\$13,512,000	\$5,889,000	\$5,159,000	\$1,145,000	\$0	\$298,000	\$1,021,000
3	Less: Load Disptach - Reliability, Planning & Standards Devel	opment Services (321.92.6)	\$3,814,000	\$1,710,000	\$1,466,000	\$344,000	\$0	\$0	\$294,000
4	Total 561 Internally Developed Costs	(Ln 1 - Ln 2 - Ĺn 3)	\$4,646,000	\$2,732,000	\$527,000	\$468,000	\$9,000	\$858,000	\$52,000
5	Less: PTP Service Credit		\$520,911	\$306,312	\$59,087	\$52,472	\$1,009	\$96,199	\$5,830
6	EXISTING ZONAL ARR	(Ln 4 - Ln 5)	\$4,125,089	\$2,425,688	\$467,913	\$415,528	\$7,991	\$761,801	\$46,170
7	PRIOR YEAR TRUE-UP with Interest	(Worksheet Q)	-\$11,355,629	-\$2,766,466	-\$1,362,043	-\$762,289	-\$43,982	-\$6,142,114	-\$278,736
8	Net Schedule 1A Revenue Requirement for Zone		-\$7,230,540	-\$340,779	-\$894,130	-\$346,761	-\$35,991	-\$5,380,313	-\$232,566

B. Schedule 1A Rate Calculations
9 2022 AEP East Zone Annual MWh 128,406,000 MWh

(Line 8 / Line 9) 10 AEP Zone Rate for Schedule 1A Service. -\$0.0563

Attachment B

Revised Calculation of the AEP East Transcos Annual Update with Kentucky Transco's Revenue Requirement Removed

AEPTCo subsidiaries in PJM - Transmission Formula Rate Revenue Requirement

Forecasted Costs through December 31, 2022 For rates effective January 1, 2022

Revenue Requirements for Network and Point-to-Point Transmission Service

In PUM VIX V				AEPTCo subsidiaries			APPALACHIAN TRANSMISSION	INDIANA MICHIGAN TRANSMISSION	KENTUCKY TRANSMISSION	OHIO TRANSMISSION	WEST VIRGINIA TRANSMISSION
No.				in PJM i	n PJM w/ KY Transco	in PJM Difference					
REVENUE REQUIREMENT (w/o noembres)											
REVENUE REQUIREMENT (w/o noembres)	A. Net	work Service									
CURRENT YEAR AEPTCO. ANNUAL TRANSMISSION 3 REVENUE REQUIREMENT (PTRR) (TCOS Ln 3) \$1,449,385,207 \$1,470,317,331 \$20,932,124 \$13,712,008 \$416,317,870 \$774,764,942 \$244,590,31 4 LESS. REVENUE REQUIREMENTS INCLUDED IN LINE I FOR: 5 RETEP UPGRADES ATRIK (WIO INCENTIVES) (TCOS Ln 5) \$144,533,762 \$149,646,973 \$5,113,210 \$0 \$48,028,719 \$344,875,793 \$51,822,210 \$0 \$0 \$48,028,719 \$344,875,793 \$51,822,210 \$0 \$0 \$48,028,719 \$344,875,793 \$51,822,210 \$0 \$0 \$48,028,719 \$344,875,793 \$51,822,210 \$0 \$0 \$48,028,719 \$344,875,793 \$51,822,210 \$0 \$0 \$48,028,719 \$344,875,793 \$51,822,210 \$0 \$0 \$48,028,719 \$344,875,793 \$51,822,210 \$0 \$0 \$48,028,719 \$344,875,793 \$51,822,210 \$0 \$0 \$48,028,719 \$344,875,793 \$51,822,210 \$0 \$0 \$48,028,719 \$344,875,793 \$51,822,210 \$0 \$0 \$48,028,719 \$344,875,793 \$51,822,210 \$0 \$0 \$48,028,719 \$344,875,793 \$51,822,210 \$0 \$0 \$48,028,719 \$344,875,793 \$51,822,210 \$0 \$0 \$48,028,719 \$344,875,793 \$51,822,210 \$0 \$0 \$48,028,719 \$344,875,793 \$51,822,210 \$0 \$0 \$0 \$0 \$0 \$0 \$0 \$0 \$0 \$0 \$0 \$0 \$0	1		(TCOS Ln 1)	\$1,463,931,207	\$1,484,863,331	\$20,932,124	\$13,712,008	\$418,046,870		\$787,581,942	\$244,590,387
REVENUE REQUIREMENT SINCLUDED IN LINE 1 FOR: LESS: REVENUE REQUIREMENT SINCLUDED IN LINE 1 FOR: STEP UPGRADES ATRR (WIO INCENTIVES) (TCOS Ln.5) \$144,533,762 \$149,646,973 \$5,113,210 \$0 \$48,028,719 \$48,028,719 \$48,075,793 \$51,629,219 \$144,653,762 \$149,646,973 \$5,113,210 \$0 \$0 \$49,028,719 \$44,075,793 \$51,629,219 \$144,653,762 \$144,653,762 \$149,646,973 \$5,113,210 \$0 \$0 \$0 \$0 \$0 \$0 \$0	2	LESS: REVENUE CREDITS	(TCOS Ln 2)	\$14,546,000	\$14,546,000	\$0	\$0	\$1,729,000		\$12,817,000	\$0
5 RTEP UPGRADES ATTAR (W/O INCENTIVES) (TOOS In. 5) \$144,533,762 \$149,646,973 \$5,113,210 \$0 \$48,022,719 \$44,873,783 \$51,629,21 \$7 OTHER UPGRADES ATTAR (W/O INCENTIVES) (Worksheet J) \$144,533,762 \$149,646,973 \$5,113,210 \$50 \$48,022,719 \$44,875,783 \$51,629,21 \$8 EXISTING AEPTCO ZONAL PTERR (W/O INCENTIVES) (Ln. 3- Ln. 7) \$1,304,851,445 \$1,320,670,358 \$15,818,913 \$13,712,008 \$368,289,152 \$729,889,150 \$192,081,11 \$9 INCREMENTAL APPROVED INCENTIVE PTER (Worksheet J) \$0 \$0 \$0 \$0 \$0 \$0 \$0 \$0 \$0 \$0 \$0 \$0 \$0	3		(TCOS Ln 3)	\$1,449,385,207	\$1,470,317,331	\$20,932,124	\$13,712,008	\$416,317,870		\$774,764,942	\$244,590,387
6 OTHER UPGRADES ATER (W/O INCENTIVES) 7 SUBTOTAL 8 EXISTING AEPTCO ZONAL PTRR (W/O INCENTIVES) 8 EXISTING AEPTCO ZONAL PTRR (W/O INCENTIVES) 9 INCREMENTAL APPROVED INCENTIVE PTRR (Worksheet.J) 9 INCREMENTAL APPROVED INCENTIVE PTRR (Worksheet.J) 10 EXISTING AEPTCO ZONAL PTRR (W/I INCENTIVES) 11 PRIOR YEAR TRUE-UP (2018 INCLUDING INTEREST) 12 EXISTING AEPTCO ZONAL PTRR (W/I INCENTIVES) 13 AEP East Zone Defined and PJM OATT Section 30.9 14 EXISTING AEPTCO PTRR FOR AEP ZONE OF PJM OATT 15 Annual Point-to-Point Rate in SMMV - Vear 16 Annual Point-to-Point Rate in SMMV - Weekly 17 Daily Off-Peak Point-to-Point Rate in SMMV - Day 18 Daily Off-Peak Point-to-Point Rate in SMMV - Day 19 Hourly Off-Peak Point-to-Point Rate in SMMV - Hour 10 (Lin 14 / 150) 11 St. 427 11 St. 427 12 EXISTING AEPTCO POINT RATE in SMMV - Poay 11 Annual Point-to-Point Rate in SMMV - Day 12 (Lin 14 / 120) 13 AEP East Zone Network Service Peak Load (1 CP) 14 Annual Point-to-Point Rate in SMMV - Weekly 15 Daily Off-Peak Point-to-Point Rate in SMMV - Day 16 Lin 14 / 120) 17 Daily Off-Peak Point-to-Point Rate in SMMV - Day 18 Daily Off-Peak Point-to-Point Rate in SMMV - Hour 19 Hourly Off-Peak Point-to-Point Rate in SMMV - Hour 10 Lin 14 / 14 / 150) 11 Part off the sum of the Point Rate in SMMV - Hour 10 Lin 14 / 14 / 150) 11 Part off the SMM - Day 11 Clin 14 / 14 / 150) 11 Part off the SMM - Day 12 Lin 14 / 14 / 150 13 AEP East Zone Network Service Peak Load (1 CP) 15 Monthly Point-to-Point Rate in SMMV - Hour 16 Lin 14 / 150 17 Daily Off-Peak Point-to-Point Rate in SMMV - Day 18 Lin 14 / 150 19 Laurly Off-Peak Point-to-Point Rate in SMMV - Day 19 Lin 14 / 150 19 Lourly Off-Peak Point-to-Point Rate in SMMV - Hour 19 Lin 14 / 150 19 Lourly Off-Peak Point-to-Point Rate in SMMV - Hour 19 Lin 14 / 150 19 Lourly Off-Peak Point-to-Point Rate in SMMV - Hour 19 Lin 14 / 150 19 Lourly Off-Peak Point-to-Point Rate in SMMV - Hour 10 Lin 14 / 150 19 Lourly Off-Peak Point-to-Point Rate in SMMV - Hour 19 Lin 14 / 150 19 Lin 14 / 150 19 Lin 15 / 150 19 Lin 15 /			(TCOS Ln 5)	\$144 533 762	\$149 646 973	\$5 113 210	\$0	\$48 028 719		\$44 875 793	\$51.629.251
## SUBTOTAL \$144,533,762 \$149,646,973 \$5,113,210 \$0 \$48,026,719 \$44,875,793 \$51,629,21 \$ ## EXISTING AEPTCo ZONAL PTRR (WO INCENTIVES) (Ln 3-Ln 7) \$1,304,851,445 \$1,320,670,358 \$15,818,913 \$13,712,008 \$368,289,152 \$729,889,150 \$192,961,11 \$ ## INCREMENTAL APPROVED INCENTIVE PTRR (Worksheet J) \$0 \$0 \$0 \$0 \$0 \$0 \$0 \$0 \$0 \$0 \$0 \$0 \$0	6										\$0
9 INCREMENTAL APPROVED INCENTIVE PTRR (Worksheet J) \$0 \$0 \$0 \$0 \$0 \$0 \$0 \$0 \$0 \$0 \$0 \$0 \$0	7		,	\$144,533,762	\$149,646,973						\$51,629,251
10 EXISTING AEPTCo ZONAL PTRR (W INCENTIVES) (Ln 8 + Ln 9) \$1,304,851,445 \$1,320,670,358 \$15,818,913 \$13,712,008 \$368,289,152 \$729,889,150 \$192,961,173	8	EXISTING AEPTCo ZONAL PTRR (W/O INCENTIVES)	(Ln 3- Ln 7)	\$1,304,851,445	\$1,320,670,358	\$15,818,913	\$13,712,008	\$368,289,152		\$729,889,150	\$192,961,136
11 PRIOR YEAR TRUE-UP (2018 INCLUDING INTEREST) (Worksheet R) -\$7,644,859 -\$8,187,216 -\$542,357 \$871,203 -\$1,670,283 \$13,414,061 -\$20,259,84	9	INCREMENTAL APPROVED INCENTIVE PTRR	(Worksheet J)	\$0	\$0	\$0	\$0	\$0		\$0	\$0
11a Facility Credits under PJM OATT Section 30.9 (TCOS Ln 3) \$4,055,395 \$4,055,395 \$0 \$4,055,395 \$14,583,210 \$366,618,869 \$747,358,606 \$172,701,21 \$1.0	10	EXISTING AEPTCo ZONAL PTRR (W/ INCENTIVES)	(Ln 8 + Ln 9)	\$1,304,851,445	\$1,320,670,358	\$15,818,913	\$13,712,008	\$368,289,152		\$729,889,150	\$192,961,136
EXISTING AEPTCO PTRR FOR AEP ZONE OF PJM OATT (Ln 10 + Ln 11) \$1,301,261,981 \$1,316,538,537 \$15,276,556 \$14,583,210 \$366,618,869 \$747,358,606 \$172,701,255 \$15,276,556 \$14,583,210 \$366,618,869 \$747,358,606 \$172,701,255 \$15,276,556 \$15,	11	PRIOR YEAR TRUE-UP (2018 INCLUDING INTEREST)	(Worksheet R)	-\$7,644,859	-\$8,187,216	-\$542,357	\$871,203	-\$1,670,283		\$13,414,061	-\$20,259,840
B. <u>Point-to-Point Service</u> 13	11a	Facility Credits under PJM OATT Section 30.9	(TCOS Ln 3)	\$4,055,395	\$4,055,395	\$0				\$4,055,395	
13 AEP East Zone Network Service Peak Load (1 CP) 21,925.3 21,925.3 - MW 14 Annual Point-to-Point Rate in \$/MW - Year (Ln 12 / Ln 13) \$59,349.79 \$60,046.55 \$696.75 15 Monthly Point-to-Point Rate in \$/MW - Month (Ln 14 / 12) \$4,945.82 \$5,003.88 \$88.06 16 Weekly Point-to-Point Rate in \$/MW - Weekly (Ln 14 / 52) \$1,141.34 \$1,154.74 \$13.40 17 Daily On-Peak Point-to-Point Rate in \$/MW - Day (Ln 14 / 260) \$228.27 \$230.95 \$2.68 18 Daily Off-Peak Point-to-Point Rate in \$/MW - Day (Ln 14 / 365) \$162.60 \$164.51 \$1.91 19 Hourly On-Peak Point-to-Point Rate in \$/MW - Hour (Ln 14 / 4160) \$14.27 \$14.43 \$0.17 20 Hourly Off-Peak Point-to-Point Rate in \$/MW - Hour (Ln 14 / 4860) \$6.78 \$6.85 \$0.08	12	EXISTING AEPTCo PTRR FOR AEP ZONE OF PJM OATT	(Ln 10 + Ln 11)	\$1,301,261,981	\$1,316,538,537	\$15,276,556	\$14,583,210	\$366,618,869		\$747,358,606	\$172,701,296
13 AEP East Zone Network Service Peak Load (1 CP) 21,925.3 21,925.3 - MW 14 Annual Point-to-Point Rate in \$/MW - Year (Ln 12 / Ln 13) \$59,349.79 \$60,046.55 \$696.75 15 Monthly Point-to-Point Rate in \$/MW - Month (Ln 14 / 12) \$4,945.82 \$5,003.88 \$88.06 16 Weekly Point-to-Point Rate in \$/MW - Weekly (Ln 14 / 52) \$1,141.34 \$1,154.74 \$13.40 17 Daily On-Peak Point-to-Point Rate in \$/MW - Day (Ln 14 / 260) \$228.27 \$230.95 \$2.68 18 Daily Off-Peak Point-to-Point Rate in \$/MW - Day (Ln 14 / 365) \$162.60 \$164.51 \$1.91 19 Hourly On-Peak Point-to-Point Rate in \$/MW - Hour (Ln 14 / 4160) \$14.27 \$14.43 \$0.17 20 Hourly Off-Peak Point-to-Point Rate in \$/MW - Hour (Ln 14 / 4860) \$6.78 \$6.85 \$0.08	B. Poi	nt-to-Point Service									
14 Annual Point-to-Point Rate in \$/MW - Year (Ln 12 / Ln 13) \$59,349.79 \$60,046.55 \$696.75 15 Monthly Point-to-Point Rate in \$/MW - Month (Ln 14 / 12) \$4,945.82 \$5,003.88 \$58.06 16 Weekly Point-to-Point Rate in \$/MW - Weekly (Ln 14 / 52) \$1,141.34 \$1,154.74 \$13.40 17 Daily On-Peak Point-to-Point Rate in \$/MW - Day (Ln 14 / 260) \$228.27 \$230.95 \$2.68 18 Daily Off-Peak Point-to-Point Rate in \$/MW - Day (Ln 14 / 365) \$162.60 \$164.51 \$1.91 19 Hourly On-Peak Point-to-Point Rate in \$/MW - Hour (Ln 14 / 4160) \$14.27 \$14.43 \$0.17 20 Hourly Off-Peak Point-to-Point Rate in \$/MW - Hour (Ln 14 / 8760) \$6.78 \$6.85 \$0.08				21.925.3	21,925,3	- MW	1				
16 Weekly Point-to-Point Rate in \$/MW - Weekly (Ln 14 / 52) \$1,141.34 \$1,154.74 \$13.40 17 Daily On-Peak Point-to-Point Rate in \$/MW - Day (Ln 14 / 260) \$228.27 \$230.95 \$2.68 18 Daily Off-Peak Point-to-Point Rate in \$/MW - Day (Ln 14 / 365) \$162.60 \$164.51 \$1.91 19 Hourly On-Peak Point-to-Point Rate in \$/MW - Hour (Ln 14 / 4160) \$14.27 \$14.43 \$0.17 20 Hourly Off-Peak Point-to-Point Rate in \$/MW - Hour (Ln 14 / 8760) \$6.78 \$6.85 \$0.08	14	Annual Point-to-Point Rate in \$/MW - Year	(Ln 12 / Ln 13)	\$59,349.79	\$60,046.55	\$696.75					
17 Daily Ón-Peak Point-to-Point Rate in \$/MW - Day (Ln 14/260) \$228.27 \$230.95 \$2.68 18 Daily Off-Peak Point-to-Point Rate in \$/MW - Day (Ln 14/365) \$162.60 \$164.51 \$1.91 19 Hourly On-Peak Point-to-Point Rate in \$/MW - Hour (Ln 14/4160) \$14.27 \$14.43 \$0.17 20 Hourly Off-Peak Point-to-Point Rate in \$/MW - Hour (Ln 14/8760) \$6.78 \$6.85 \$0.08	15	Monthly Point-to-Point Rate in \$/MW - Month	(Ln 14 / 12)	\$4,945.82	\$5,003.88	\$58.06					
18 Daily Off-Peak Point-to-Point Rate in \$/MW - Day (Ln 14 / 365) \$162.60 \$164.51 \$1.91 19 Hourly On-Peak Point-to-Point Rate in \$/MW - Hour (Ln 14 / 4160) \$14.27 \$14.43 \$0.17 20 Hourly Off-Peak Point-to-Point Rate in \$/MW - Hour (Ln 14 / 8760) \$6.78 \$6.85 \$0.08	16	Weekly Point-to-Point Rate in \$/MW - Weekly	(Ln 14 / 52)	\$1,141.34	\$1,154.74	\$13.40					
19 Hourly On-Peak Point-to-Point Rate in \$MMV - Hour (Ln 14 / 4160) \$14.27 \$14.43 \$0.17 20 Hourly Off-Peak Point-to-Point Rate in \$MW - Hour (Ln 14 / 8760) \$6.78 \$6.85 \$0.08	17	Daily On-Peak Point-to-Point Rate in \$/MW - Day	(Ln 14 / 260)	\$228.27	\$230.95	\$2.68					
20 Hourly Off-Peak Point-to-Point Rate in \$/MW - Hour (Ln 14 / 8760) \$6.78 \$6.85 \$0.08	18	Daily Off-Peak Point-to-Point Rate in \$/MW - Day	(Ln 14 / 365)		\$164.51	\$1.91					
	19										
C. PJM Regional Service	20	Hourly Off-Peak Point-to-Point Rate in \$/MW - Hour	(Ln 14 / 8760)	\$6.78	\$6.85	\$0.08					
	C. PJM	// Regional Service									
21 RTEP UPGRADE PTRR W/O INCENTIVES (Ln 7) 144,533,762 149,646,973 5,113,210 - 48,028,719 44,875,793 51,629,25			(Ln 7)	144,533,762	149,646,973	5,113,210		48,028,719		44,875,793	51,629,251
22 ADDITIONAL ATRR FOR FERC-APPROVED INCENTIVES ON RTEF (Worksheet J)	22	ADDITIONAL ATRR FOR FERC-APPROVED INCENTIVES ON RTI			-			-			-
				10,196,062	9,954,382	(241,680)	-	2,661,868		(2,436,143)	9,970,337
	24		. /				-				61,599,588

AEPTCo subsidiaries in PJM - Transmission Formula Rate Revenue Requirement

Forecasted Costs through December 31, 2022 For charges effective January 1, 2022

Annual Revenue Requirement for Scheduling, System Control and Dispatch Services - Schedule 1A

			AEPTCo subsidiaries in PJM	APPALACHIAN TRANSMISSION COMPANY	INDIANA MICHIGAN TRANSMISSION COMPANY	KENTUCKY TRANSMISSION COMPANY	OHIO TRANSMISSION COMPANY	WEST VIRGINIA TRANSMISSION COMPANY
Line No.			Annual Revenue Requirement	Annual Revenue Requirement	Annual Revenue Requirement	Annual Revenue Requirement	Annual Revenue Requirement	Annual Revenue Requirement
A. Sched	dule 1A ARR							
1	Total Load Dispatch & Scheduling (Account 561) (TCOS Line 15)		\$3,367,000	\$16,000	\$1,139,000	\$24,000	\$1,902,000	\$286,000
2	Less: Load Disptach - Scheduling, System Control and Dispatch S	Services (321.88.b)	\$0	\$0	\$0	\$0	\$0	\$0
3	Less: Load Disptach - Reliability, Planning & Standards Developm	nent Services (321.92.6)	\$0	\$0	\$0	\$0	\$0	\$0
4	Total 561 Internally Developed Costs	(Ln 1 - Ln 2 - Ln 3)	\$3,367,000	\$16,000	\$1,139,000	\$24,000	\$1,902,000	\$286,000
5	Less: PTP Service Credit		\$0	\$0	\$0	\$0	\$0	\$0
6	EXISTING ZONAL ARR	(Ln 4 - Ln 5)	\$3,367,000	\$16,000	\$1,139,000	\$24,000	\$1,902,000	\$286,000
7	PRIOR YEAR TRUE-UP (Including Interest)	(Worksheet R)	-\$745,474	\$40,895	-\$502,404	\$41,464	-\$834,943	\$509,515
8	Net Schedule 1A Revenue Requirement for Zone		\$2,621,526	\$56,895	\$636,596	\$65,464	\$1,067,057	\$795,515

Sched	ule 1A Rate Calculations		
9	AEP East Zone Annual MWh		128,406,000
	Line 10 is provided from PJM records		
10	AEP Zone Rate for Schedule 1A Service.	(Line 8 / Line 9)	\$0.0204