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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").[1]

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

[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.

[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]

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[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.[6] 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.

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[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.[10] 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. §§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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Marked Att. H-14

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. **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 Parties[1] 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;

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

[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

D. 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 Year[3] 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

3 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.

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[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]

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[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;

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 True-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. <u>Annual Review Procedures</u>

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%

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

AEP East Companies
Cost of Service Formula Rate Using Actual/Projected FF1 Balances
Worksheet H Supporting Taxes Other than Income
COMPANY NAME HERE

Line No.	(A) Account	(B) Total Company NOTE 1	(C) Property	(D) Labor	(E) Other	(F) Non-Allocable
1	**Revenue Taxes**					
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	**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	-	-	-	-	-

(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 is shown on WS H-1.

Functional Property Tax Allocation

Line No.		Production	Transmsission	Distribution	General	Total
25	Functionalized Net Plant (TCOS, Lns 41 thru 46)	-	-	-	-	-
	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	Taxable Property Basis (Ln 27 - Ln 28)	-	-	-	-	-
30	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)	-	-	-	-	-
35	Functional Percentage (Ln 34/Total Ln 34)	0.00%	0.00%	0.00%		
	STATE JURISDICTION #2					
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)	-	-	-	-	
42	General Plant Allocator (Ln 41 / (Total - General Plant))	0.00%	0.00%	0.00%	-100.00%	
43	Functionalized General Plant (Ln 42 * General Plant)	-	-	-	-	-
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	Taxable Property Basis	-	-	-	-	-
49	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)	-	-	-	-	
53	Weighted STATE JURISDICTION #3 Plant (Ln 50 + 52)	-	-	-	-	-
54	Functional Percentage (Ln 53/Total Ln 53)	0.00%	0.00%	0.00%		

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

Line No.	(A) Annual Tax Expenses by Type (Note 1)	(B) Total Company	(C) FERC FORM 1 Tie-Back	(D) FERC FORM 1 Reference
1	**Revenue Taxes**			
2	Revenue Tax 1	-		

Line No.	(A) Real Estate and Personal Propety Tax Detail Annual Tax Expenses by Type (Note 1)	(B) Tax Year	(C) Total Company	(D) FERC FORM 1 Tie-Back	(E) FERC FORM 1 Reference	(F) Tax Year Factor (Note 2)	(G) Transmission 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		-				-

Line No.	(A) Annual Tax Expense by Type (Note 1)	(B) Total Company	(C) FERC FORM 1 Tie-Back	(D) 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.

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.

A. 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 through156)

	%	Cost		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%

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

B. Determine Return using 'R' with hypothetical basis point ROE increase for Identified Projects.

Rate Base (TCOS, ln 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.

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 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		0.00%
Annual Rev. Req, w / Basis Point ROE increase, less Dep.	-	
FCR with Basis Point ROE increase, less Depreciation		0.00%
FCR less Depreciation (TCOS, ln 10)		0.00%
Incremental FCR with Basis Point ROE increase, less Depreciation		0.00%

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		0.00%
Depreciable Life for Composite Depreciation Rate	-	
Round to nearest whole year	-	

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. (e.g. ER05-925-000)

Current Projected Year ARR	**-**
Current Projected Year ARR w/ Incentive	**-**
Current Projected Year Incentive ARR	-

Project Description:

Details			
Investment		Current Year	**Projected Year**
Service Year (yyyy)		ROE increase accepted by FERC (Basis Points)	-
Service Month (1-12)		FCR w/o incentives, less depreciation	0.00%
Useful life	-	FCR w/incentives approved for these facilities, less dep.	0.00%
CIAC (Yes or No)		Annual Depreciation Expense	-

Investment Year	**Beginning Balance**	**Depreciation Expense**	**Ending Balance**	**RTEP Rev. Req't. w/o Incentives**	**RTEP Rev. Req't. with Incentives ****	**Incentive Rev. Requirement ##**
-	-	-	-	-	-	$ -
-	-	-	-	-	-	$ -
Project Totals		-		-	-	-

CUMULATIVE HISTORY OF PROJECTED ANNUAL REVENUE REQUIREMENTS:

CUMULATIVE HISTORY OF PROJECTED ANNUAL REVENUE REQUIREMENTS:
INPUT PROJECTED ARR (WITH & WITHOUT INCENTIVES) FROM EACH PRIOR YEAR TEMPLATE BELOW TO MAINTAIN HISTORY OF PROJECTED ARRS OVER THE LIFE OF THE PROJECT.

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.

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.

AEP East Companies
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
COMPANY NAME HERE

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

A. 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 through156)

	%	Cost	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%

B. Determine Return using 'R' with hypothetical basis point ROE increase for Identified Projects.

Rate Base (TCOS, ln 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.

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)		-
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	-

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	-	-	-

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		0.00%
Annual Rev. Req, w / Basis Point ROE increase, less Dep.	-	
FCR with Basis Point ROE increase, less Depreciation		0.00%
FCR less Depreciation (TCOS, ln 10)		0.00%
Incremental FCR with Basis Point ROE increase, less Depreciation		0.00%

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		0.00%
Depreciable Life for Composite Depreciation Rate	-	
Round to nearest whole year	-	

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. (e.g. ER05-925-000)

Project Description:

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

Details

Investment		Current Year	**Historic Year**
Service Year (yyyy)		ROE increase accepted by FERC (Basis Points)	-
Service Month (1-12)		FCR w/o incentives, less depreciation	0.00%
Useful life	-	FCR w/incentives approved for these facilities, less dep.	0.00%
CIAC (Yes or No)	No	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 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.

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 **
	$ -		$ -	$ -
	$ -		$ -	$ -

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				
Line No	Month (a)	Proprietary Capital (b)	Less: Preferred Stock (c)	Less Undistributed Sub Earnings (Acct 216.1) (d)	Less AOCI (Acct 219.1) (e)	Average Balance of Common Equity (f)=(b)-(c)-(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					
Line No	Month (a)	Acct 221 Bonds (b)	Less: Acct 222 Reacquired Bonds (c)	Acct 223 LT Advances from Assoc. Companies (d)	Acct 224 Senior Unsecured Notes (e)	Less: Fair Value Hedges (f)	Gross Proceeds Outstanding Long-Term Debt (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)

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**						
30	Interest on Long Term Debt - Accts 221 - 224 (256-257.33.i)						
31	Less: Total Hedge Gain/Expense Accumulated from p 256-257, col. (i) of FERC Form 1 included in Ln 30 and shown in 50 below.			-			
32	Plus: Allowed Hedge Recovery From Ln 55 below.			-			
33	Amort of Debt Discount & Expense - Acct 428 (117.63.c)						
34	Amort of Loss on Reacquired Debt - Acct 428.1 (117.64.c)						
35	Less: Amort of Premium on Debt - Acct 429 (117.65.c)						
36	Less: Amort of Gain on Reacquired Debt - Acct 429.1 (117.66.c)						
37	**Total Interest Expense (Ln 30 - 31 + 33 + 34 - 35 - 36)**			-			
38	**Average Cost of Debt for 2017 (Ln 37/ 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. <u>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.</u>

	HEDGE AMOUNTS BY ISSUANCE (FROM p. 256-257 (i) of the FERC Form 1)	Total Hedge (Gain)/Loss for 2017	Less Excludable Amounts (See NOTE on Line 39)	Net Includable Hedge Amount	Remaining Unamortized Balance	Amortization Period Begin ning	Amortization Period Ending
40				-			
41				-			
42				-			
43				-			
44				-			
45				-			
46				-			
47				-			
48				-			
49					-		
50	Total Hedge Amortization	-	-				

51	Hedge Gain or Loss Prior to Application of Recovery Limit (Sum of Lines 40 to 48)			-
52	Total Average Capital Structure Balance for 2017 (TCOS, Ln 157)			-
53	Financial Hedge Recovery Limit - Five Basis Points of Total Capital			0.0005
54	Limit of Recoverable Amount			-
55	**Recoverable Hedge Amortization (Lesser of Ln 51 or Ln 54)**			**-**

Development of Cost of Preferred Stock

	<u>**Preferred Stock**</u>			<u>**Average**</u>
56	0% Series - 0 - Dividend Rate (p. 250-251)	0.000%	0.000%	
57	0% Series - 0 - Par Value (p. 250-251)	$ -	$ -	
58	0% Series - 0 - Shares O/S (p.250-251)	-	-	
59	0% Series - 0 - Monetary Value (Ln 57 * 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)	$ -	$ -			
63	0% Series - 0 - Shares O/S (p.250-251)	-	-			
64	0% Series - 0 - Monetary Value (Ln 62 * 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)	-	-			
69	0% Series - 0 - Monetary Value (Ln 67 * Ln 68)	-	-	-		
70	0% Series - 0 - Dividend Amount (Ln 66 * Ln 69)	-	-	-		
71	**Balance of Preferred Stock (Lns 59, 64, 69)**			-	-	**-**	Year End Total Agrees to FF1 p.112, Ln 3, col (c) & (d)
72	**Dividends on Preferred Stock (Lns 60, 65, 70)**			-	-	**-**	
73	**Average Cost of Preferred Stock (Ln 72/71)**			0.00%	0.00%	**0.00%**	

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 G = General	**Basis**	**Proceeds**	**(Gain) / Loss**	**Functional Allocator**	**Functionalized Proceeds (Gain) / Loss**	**FERC Account**
1						-	0.000%	-	
2						-	0.000%	-	
3						-	0.000%	-	
4				Net (Gain) or Loss for 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%~~	~~-~~	-	~~-~~	~~-~~	~~-~~
4~~5~~	KNGP		0.00%	-		-	-	-
5~~6~~	OPCo		0.00%	-		-	-	-
6~~7~~	WPCo		0.00%	-		-	-	-
7~~8~~	**Sum of Lines 2 to 6~~7~~**	-		-		-	-	-

Detail of Actual PBOP Expenses to be Removed in Cost of Service

		APCo	I&M	~~KPCo~~	KNGSPT	OPCo	WPCo	AEP East Total
8~~9~~	Direct Charged PBOP Expense per Actuarial Report							-
9~~10~~	Additional PBOP Ledger Entries (from Company Records)							
10~~11~~	Medicare Subsidy							-
11~~12~~	Net Company Expense (Ln 8~~9~~ + Ln 9~~10~~ + Ln 10~~11~~)	-	-	-	-	-	-	-
12~~13~~	PBOP Expenses From AEP Service Corporation (from Company Records)							-
13 ~~14~~	Company PBOP Expense (Ln 11~~12~~ + Ln 12~~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% 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 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 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

FOR TRANSMISSION PLANT PROPERTY ACCOUNT

EFFECTIVE AS OF 3/6/2019

FOR MULTIPLE JURISDICTION COMPANIES

APPALACHIAN POWER COMPANY

		VIRGINIA			**WEST VIRGINIA**						**FERC WHOLESALE**		**FERC KINGSPORT**		**COMPANY**
		(1)			(2)						(3)		(4)		
	PLANT ACCT.	VA SCC RATES	ALLOCATION FACTOR (5)	WTD AVG. DEPREC. RATE	PSC OF WV APPROVED RATES	ALLOCATION FACTOR (5)	WTD AVG. DEPREC. RATE	FERC RATES	ALLOCATION FACTOR (5)	WTD AVG. DEPREC. RATE	FERC RATES	ALLOCATION FACTOR (5)	DEPREC. RATE		WTD AVG. DEPREC. RATE
TRANSMISSION PLANT															
Land Rights - Va.	350.1	0.66%	1.000000	0.66%											0.66%
Energy Storage Equipment (6)	351.0				14.22%	1.000000	14.22%								14.22%
Structures & Improvements	352.0	1.55%	0.492648	0. 76%	1.62%	0.414603	0.67%	2.19%	0.033874	0.07%	2.19%	0.058874	0.13%		1.63%
Station Equipment	353.0	1.95%	0.492648	0. 96%	2.37%	0.414603	0.98%	2.19%	0.033874	0.07%	2.19%	0.058874	0.13%		2.14%
Towers & Fixtures	354.0	1.14%	0.492648	0.56%	1.59%	0.414603	.0.66%	2.19%	0.033874	0.07%	2.19%	0.058874	0.13%		1.42%
Poles & Fixtures	355.0	2.77%	0.492648	1.36%	2.71%	0.414603	1.12%	2.19%	0.033874	0.07%	2.19%	0.058874	0.13%		2.68%
Overhead Conductor	356.0	1.01%	0..492648	0.50%	1.53%	0.414603	.0.63%	2.19%	0.033874	0.07%	2.19%	0.058874	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%	0.058874	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%	0.058874	0.13%		3.94%
GENERAL PLANT															
Structures and Improvements	390.0	1.50%	0.519557	0.78%	1.91%	0.425935	0.81%	3.43%	0.019780	0.07%	3.43%	0.034728	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%	0.034728	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%	0.034728	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%	0.034728	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%	0.034728	0.12%		2.36%
Laboratory Equipment	395.0	1.53%	0.519557	0.79%	4.01%	0.425935	1.71%	3.43%	0.019780	0.07%	3.43%	0.034728	0.12%		2.69%
Power Operated Equipment	396.0	0.00%	0.519557	0.00%	3.90%	0.425935	1.66%	3.43%	0.019780	0.07%	3.43%	0.034728	0.12%		1.85%
Communications Equipment	397.0	3.27%	0.519557	1.70%	4.98%	0.425935	2.12%	3.43%	0.019780	0.07%	3.43%	0.034728	0.12%		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%	0.034728	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.

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

(3) Approved by FERC March 2, 1990 in Docket ER90-132

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

(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' 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
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			**MICHIGAN**			**FERC WHOLESALE**			**TOTAL COMPANY**
	PLANT ACCT.	(1) IURC RATES	ALLOCATION FACTOR (4)	WTD AVG. DEPREC. RATE	(2) MPSC APPROVED RATES	ALLOCATION FACTOR (4)	WTD AVG. DEPREC. RATE	(3) FERC RATES	ALLOCATION FACTOR (4)	WTD AVG. DEPREC. RATE	WTD AVG. DEPREC. RATE
TRANSMISSION PLANT											
Land Improvements	350.1	1.66%	0.6623353	1.0995%	1.62%	0.3376647	0.5470%	1.62%	0.3376647	0.5470%	1.65%
Structures & 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	357.0	2.30%	0.6623353	1.5234%	2.21%	0.3376647	0.7462%	2.21%	0.3376647	0.7462%	2.27%
Underground 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 Improvements	390.0	2.08%	0.6818683	1.4183%	2.08%	0.3181317	0.6617%	2.08%	0.3181317	0.6617%	2.08%
Office Furniture and Equip.	391.0	4.79%	0.6818683	3.2661%	4.84%	0.3181317	1.5398%	4.84%	0.3181317	1.5398%	4.81%
Transportation Equipment	392.0	4.64%	0.6818683	3.1639%	4.68%	0.3181317	1.4889%	4.68%	0.3181317	1.4889%	4.65%
Stores Equipment	393.0	7.35%	0.6818683	5.0117%	7.38%	0.3181317	2.3478%	7.38%	0.3181317	2.3478%	7.36%
Tools, Shop and Garage Equipment	394.0	6.99%	0.6818683	4.7663%	7.07%	0.3181317	2.2492%	7.07%	0.3181317	2.2492%	7.02%
Laboratory Equipment	395.0	5.41%	0.6818683	3.6889%	5.46%	0.3181317	1.7370%	5.46%	0.3181317	1.7370%	5.43%
Power Operated Equipment	396.0	4.81%	0.6818683	3.2798%	4.90%	0.3181317	1.5588%	4.90%	0.3181317	1.5588%	4.84%
Communications Equipment	397.0	3.91%	0.6818683	2.6661%	3.93%	0.3181317	1.2503%	3.93%	0.3181317	1.2503%	3.92%
Micellaneous Equipment	398.0	3.32%	0.6818683	2.2638%	3.35%	0.3181317	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 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.~~

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 Refunds or Surcharges (Note 1)			0.2780%				

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

Calculation of Interest					Monthly		
January	Year 2018	-	0.2780%	12	-		-
February	Year 2018	-	0.2780%	11	-		-
March	Year 2018	-	0.2780%	10	-		-
April	Year 2018	-	0.2780%	9	-		-
May	Year 2018	-	0.2780%	8	-		-
June	Year 2018	-	0.2780%	7	-		-
July	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		
January through December	Year 2019	-	0.2780%	12	-		-

Over (Under) Recovery Plus Interest Amortized and Recovered Over 12 Months					Monthly		
January	Year 2020	-	0.2780%		-	-	-
February	Year 2020	-	0.2780%		-	-	-
March	Year 2020	-	0.2780%		-	-	-
April	Year 2020	-	0.2780%		-	-	-
May	Year 2020	-	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	-
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.

Clean Att. H-14

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. <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 Parties[1] 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;

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

v. Changes to income tax elections;

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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.

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

D. 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.

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[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 Year[3] 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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[3] 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.

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[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]

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[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;

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 True-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. <u>Annual Review Procedures</u>

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. **Changes to Annual Updates**

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%

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

AEP East Companies
Cost of Service Formula Rate Using Actual/Projected FF1 Balances
Worksheet H Supporting Taxes Other than Income
COMPANY NAME HERE

Line No.	(A) Account	(B) Total Company NOTE 1	(C) Property	(D) Labor	(E) Other	(F) Non-Allocable
1	**Revenue Taxes**					
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	**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	-	-	-	-	-

(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 is shown on WS H-1.

Functional Property Tax Allocation

Line No.		Production	Transmsission	Distribution	General	Total
25	Functionalized Net Plant (TCOS, Lns 41 thru 46)	-	-	-	-	-
	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	Taxable Property Basis (Ln 27 - Ln 28)	-	-	-	-	-
30	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)	-	-	-	-	-
35	Functional Percentage (Ln 34/Total Ln 34)	0.00%	0.00%	0.00%		
	STATE JURISDICTION #2					
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)	-	-	-	-	
42	General Plant Allocator (Ln 41 / (Total - General Plant))	0.00%	0.00%	0.00%	-100.00%	
43	Functionalized General Plant (Ln 42 * General Plant)	-	-	-	-	-
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	Taxable Property Basis	-	-	-	-	-
49	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)	-	-	-	-	
53	Weighted STATE JURISDICTION #3 Plant (Ln 50 + 52)	-	-	-	-	-
54	Functional Percentage (Ln 53/Total Ln 53)	0.00%	0.00%	0.00%		

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

Line No.	(A) Annual Tax Expenses by Type (Note 1)	(B) Total Company	(C) FERC FORM 1 Tie-Back	(D) FERC FORM 1 Reference
1	**Revenue Taxes**			
2	Revenue Tax 1	-		

Line No.	(A) Real Estate and Personal Propety Tax Detail Annual Tax Expenses by Type (Note 1)	(B) Tax Year	(C) Total Company	(D) FERC FORM 1 Tie-Back	(E) FERC FORM 1 Reference	(F) Tax Year Factor (Note 2)	(G) Transmission 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		-				-

Line No.	(A) Annual Tax Expense by Type (Note 1)	(B) Total Company	(C) FERC FORM 1 Tie-Back	(D) 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.

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.

A. 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 through156)

	%	Cost	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%

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

B. Determine Return using 'R' with hypothetical basis point ROE increase for Identified Projects.

Rate Base (TCOS, ln 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.

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 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		0.00%
Annual Rev. Req, w / Basis Point ROE increase, less Dep.	-	
FCR with Basis Point ROE increase, less Depreciation		0.00%
FCR less Depreciation (TCOS, ln 10)		0.00%
Incremental FCR with Basis Point ROE increase, less Depreciation		0.00%

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		0.00%
Depreciable Life for Composite Depreciation Rate	-	
Round to nearest whole year	-	

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. (e.g. ER05-925-000)

Current Projected Year ARR	-
Current Projected Year ARR w/ Incentive	-
Current Projected Year Incentive ARR	-

Project Description:

Details			
Investment		Current Year	**Projected Year**
Service Year (yyyy)		ROE increase accepted by FERC (Basis Points)	-
Service Month (1-12)		FCR w/o incentives, less depreciation	0.00%
Useful life	-	FCR w/incentives approved for these facilities, less dep.	0.00%
CIAC (Yes or No)		Annual Depreciation Expense	-

Investment Year	**Beginning Balance**	**Depreciation Expense**	**Ending Balance**	**RTEP Rev. Req't. w/o Incentives**	**RTEP Rev. Req't. with Incentives ****	**Incentive Rev. Requirement ##**
-	-	-	-	-	-	$ -
-	-	-	-	-	-	$ -
Project Totals		-		-	-	-

CUMULATIVE HISTORY OF PROJECTED ANNUAL REVENUE REQUIREMENTS:

CUMULATIVE HISTORY OF PROJECTED ANNUAL REVENUE REQUIREMENTS:
INPUT PROJECTED ARR (WITH & WITHOUT INCENTIVES) FROM EACH PRIOR YEAR TEMPLATE BELOW TO MAINTAIN HISTORY OF PROJECTED ARRS OVER THE LIFE OF THE PROJECT.

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.

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.

AEP East Companies
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
COMPANY NAME HERE

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

A. 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 through156)

	%	Cost	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%

B. Determine Return using 'R' with hypothetical basis point ROE increase for Identified Projects.

Rate Base (TCOS, ln 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.

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)		-
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	-

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	-	-	-

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		0.00%
Annual Rev. Req, w / Basis Point ROE increase, less Dep.	-	
FCR with Basis Point ROE increase, less Depreciation		0.00%
FCR less Depreciation (TCOS, ln 10)		0.00%
Incremental FCR with Basis Point ROE increase, less Depreciation		0.00%

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		0.00%
Depreciable Life for Composite Depreciation Rate	-	
Round to nearest whole year	-	

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. (e.g. ER05-925-000)

Project Description:

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

Details			
Investment		Current Year	Historic Year
Service Year (yyyy)		ROE increase accepted by FERC (Basis Points)	-
Service Month (1-12)		FCR w/o incentives, less depreciation	0.00%
Useful life	-	FCR w/incentives approved for these facilities, less dep.	0.00%
CIAC (Yes or No)	No	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 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.

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 **
	$ -		$ -	$ -
	$ -		$ -	$ -

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

Line 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)-(e)
		Average Balance of Common Equity				
	(a)	(b)	(c)	(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	-	-	-	-	-

Line 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)-(f)
		Average Balance of Long Term Debt					
	(a)	(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)

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**						
30	Interest on Long Term Debt - Accts 221 - 224 (256-257.33.i)						
31	Less: Total Hedge Gain/Expense Accumulated from p 256-257, col. (i) of FERC Form 1 included in Ln 30 and shown in 50 below.			-			
32	Plus: Allowed Hedge Recovery From Ln 55 below.			-			
33	Amort of Debt Discount & Expense - Acct 428 (117.63.c)						
34	Amort of Loss on Reacquired Debt - Acct 428.1 (117.64.c)						
35	Less: Amort of Premium on Debt - Acct 429 (117.65.c)						
36	Less: Amort of Gain on Reacquired Debt - Acct 429.1 (117.66.c)						
37	**Total Interest Expense (Ln 30 - 31 + 33 + 34 - 35 - 36)**			-			
38	**Average Cost of Debt for 2017 (Ln 37/ 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. <u>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.</u>

	HEDGE AMOUNTS BY ISSUANCE (FROM p. 256-257 (i) of the FERC Form 1)	Total Hedge (Gain)/Loss for 2017	Less Excludable Amounts (See NOTE on Line 39)	Net Includable Hedge Amount	Remaining Unamortized Balance	Amortization Period Beginning	Amortization Period Ending
40				-			
41				-			
42				-			
43				-			
44				-			
45				-			
46				-			
47				-			
48				-			
49					-		
50	Total Hedge Amortization	-	-				

51	Hedge Gain or Loss Prior to Application of Recovery Limit (Sum of Lines 40 to 48)			-
52	Total Average Capital Structure Balance for 2017 (TCOS, Ln 157)			-
53	Financial Hedge Recovery Limit - Five Basis Points of Total Capital			0.0005
54	Limit of Recoverable Amount			-
55	**Recoverable Hedge Amortization (Lesser of Ln 51 or Ln 54)**			-

Development of Cost of Preferred Stock

	Preferred Stock	(b)	(c)	Average
56	0% Series - 0 - Dividend Rate (p. 250-251)	0.000%	0.000%	
57	0% Series - 0 - Par Value (p. 250-251)	$ -	$ -	
58	0% Series - 0 - Shares O/S (p.250-251)	-	-	
59	0% Series - 0 - Monetary Value (Ln 57 * 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)	$ -	$ -				
63	0% Series - 0 - Shares O/S (p.250-251)	-	-				
64	0% Series - 0 - Monetary Value (Ln 62 * 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)	-	-				
69	0% Series - 0 - Monetary Value (Ln 67 * Ln 68)	-	-	-			
70	0% Series - 0 - Dividend Amount (Ln 66 * Ln 69)	-	-	-			
71	**Balance of Preferred Stock (Lns 59, 64, 69)**				-	-	**-**	Year End Total Agrees to FF1 p.112, Ln 3, col (c) & (d)
72	**Dividends on Preferred Stock (Lns 60, 65, 70)**				-	-	**-**	
73	**Average Cost of Preferred Stock (Ln 72/71)**				0.00%	0.00%	**0.00%**	

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 G = General	**Basis**	**Proceeds**	**(Gain) / Loss**	**Functional Allocator**	**Functionalized Proceeds (Gain) / Loss**	**FERC Account**
1						-	0.000%	-	
2						-	0.000%	-	
3						-	0.000%	-	
4				Net (Gain) or Loss for 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	KNGP		0.00%	-		-	-	-
5	OPCo		0.00%	-		-	-	-
6	WPCo		0.00%	-		-	-	-
7	**Sum of Lines 2 to 6**	-		-		-	-	-

Detail of Actual PBOP Expenses to be Removed in Cost of Service

Line #		APCo	I&M		KNGSPT	OPCo	WPCo	AEP East Total
8	Direct Charged PBOP Expense per Actuarial Report							-
9	Additional PBOP Ledger Entries (from Company Records)							
10	Medicare Subsidy							-
11	Net Company Expense (Ln 8 + Ln 9 + Ln 10)	-	-	-	-	-	-	-
12	PBOP Expenses From AEP Service Corporation (from Company Records)							-
13	Company PBOP Expense (Ln 11 + Ln 12)	-	-	-	-	-	-	

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 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 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

FOR TRANSMISSION PLANT PROPERTY ACCOUNT

EFFECTIVE AS OF 3/6/2019

FOR MULTIPLE JURISDICTION COMPANIES

APPALACHIAN POWER COMPANY

		VIRGINIA			WEST VIRGINIA					FERC WHOLESALE		FERC KINGSPORT		COMPANY
			(1)			(2)				(3)			(4)	
	PLANT ACCT.	VA SCC RATES	ALLOCATION FACTOR (5)	WTD AVG. DEPREC. RATE	PSC OF WV APPROVED RATES	ALLOCATION FACTOR (5)	WTD AVG. DEPREC. RATE	FERC RATES	ALLOCATION FACTOR (5)	WTD AVG. DEPREC. RATE	FERC RATES	ALLOCATION FACTOR (5)	WTD AVG. DEPREC. RATE	WTD AVG. DEPREC. RATE
TRANSMISSION PLANT														
Land Rights - Va.	350. 1	0.66%	1.000000	0.66%										0.66%
Energy Storage Equipment (6)	351.0				14.22%	1.000000	14.22%							14.22%
Structures & Improvements	352.0	1.55%	0.492648	0. 76%	1.62%	0.414603	0.67%	2.19%	0.033874	0.07%	2.19%	0.058874	0.13%	1.63%
Station Equipment	353.0	1.95%	0.492648	0. 96%	2.37%	0.414603	0.98%	2.19%	0.033874	0.07%	2.19%	0.058874	0.13%	2.14%
Towers & Fixtures	354.0	1.14%	0.492648	0.56%	1.59%	0.414603	.0.66%	2.19%	0.033874	0.07%	2.19%	0.058874	0.13%	1.42%
Poles & Fixtures	355.0	2.77%	0.492648	1.36%	2.71%	0.414603	1.12%	2.19%	0.033874	0.07%	2.19%	0.058874	0.13%	2.68%
Overhead Conductor	356.0	1.01%	0..49264 8	0.50%	1.53%	0.414603	.0.63%	2.19%	0.033874	0.07%	2.19%	0.058874	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%	0.058874	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%	0.058874	0.13%	3.94%
GENERAL PLANT														
Structures and Improvements	390.0	1.50%	0.519557	0.78%	1.91%	0.425935	0.81%	3.43%	0.019780	0.07%	3.43%	0.034728	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%	0.034728	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%	0.034728	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%	0.034728	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%	0.034728	0.12%	2.36%
Laboratory Equipment	395.0	1.53%	0.519557	0.79%	4.01%	0.425935	1.71%	3.43%	0.019780	0.07%	3.43%	0.034728	0.12%	2.69%
Power Operated Equipment	396.0	0.00%	0.519557	0.00%	3.90%	0.425935	1.66%	3.43%	0.019780	0.07%	3.43%	0.034728	0.12%	1.85%
Communications Equipment	397.0	3.27%	0.519557	1.70%	4.98%	0.425935	2.12%	3.43%	0.019780	0.07%	3.43%	0.034728	0.12%	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%	0.034728	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.

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

(3) Approved by FERC March 2, 1990 in Docket ER90-132

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

(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' 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
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			**MICHIGAN**			**FERC WHOLESALE**			**TOTAL COMPANY**
		(1)			(2)			(3)			
	PLANT ACCT.	IURC RATES	ALLOCATION FACTOR (4)	WTD AVG. DEPREC. RATE	MPSC APPROVED RATES	ALLOCATION FACTOR (4)	WTD AVG. DEPREC. RATE	FERC RATES	ALLOCATION FACTOR (4)	WTD AVG. DEPREC. RATE	WTD AVG. DEPREC. RATE
TRANSMISSION PLANT											
Land Improvements	350.1	1.66%	0.6623353	1.0995%	1.62%	0.3376647	0.5470%	1.62%	0.3376647	0.5470%	1.65%
Structures & 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	357.0	2.30%	0.6623353	1.5234%	2.21%	0.3376647	0.7462%	2.21%	0.3376647	0.7462%	2.27%
Underground 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 Improvements	390.0	2.08%	0.6818683	1.4183%	2.08%	0.3181317	0.6617%	2.08%	0.3181317	0.6617%	2.08%
Office Furniture and Equip.	391.0	4.79%	0.6818683	3.2661%	4.84%	0.3181317	1.5398%	4.84%	0.3181317	1.5398%	4.81%
Transportation Equipment	392.0	4.64%	0.6818683	3.1639%	4.68%	0.3181317	1.4889%	4.68%	0.3181317	1.4889%	4.65%
Stores Equipment	393.0	7.35%	0.6818683	5.0117%	7.38%	0.3181317	2.3478%	7.38%	0.3181317	2.3478%	7.36%
Tools, Shop and Garage Equipment	394.0	6.99%	0.6818683	4.7663%	7.07%	0.3181317	2.2492%	7.07%	0.3181317	2.2492%	7.02%
Laboratory Equipment	395.0	5.41%	0.6818683	3.6889%	5.46%	0.3181317	1.7370%	5.46%	0.3181317	1.7370%	5.43%
Power Operated Equipment	396.0	4.81%	0.6818683	3.2798%	4.90%	0.3181317	1.5588%	4.90%	0.3181317	1.5588%	4.84%
Communications Equipment	397.0	3.91%	0.6818683	2.6661%	3.93%	0.3181317	1.2503%	3.93%	0.3181317	1.2503%	3.92%
Micellaneous Equipment	398.0	3.32%	0.6818683	2.2638%	3.35%	0.3181317	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 Refunds or Surcharges (Note 1)			0.2780%				

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

Calculation of Interest					**Monthly**		
January	Year 2018	-	0.2780%	12	-		-
February	Year 2018	-	0.2780%	11	-		-
March	Year 2018	-	0.2780%	10	-		-
April	Year 2018	-	0.2780%	9	-		-
May	Year 2018	-	0.2780%	8	-		-
June	Year 2018	-	0.2780%	7	-		-
July	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		
January through December	Year 2019	-	0.2780%	12	-		-

Over (Under) Recovery Plus Interest Amortized and Recovered Over 12 Months					**Monthly**		
January	Year 2020	-	0.2780%		-	-	-
February	Year 2020	-	0.2780%		-	-	-
March	Year 2020	-	0.2780%		-	-	-
April	Year 2020	-	0.2780%		-	-	-
May	Year 2020	-	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	-
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.

Marked Att. H-20

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.

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1 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."

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 Parties[2] 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;

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

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[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

D. 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.

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[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 Year[4] 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

[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 credtited 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;

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 True-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. <u>Annual Review Procedures</u>

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.

g. 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 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. <u>Resolution of Challenges</u>

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

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 Plant In Service				
Line No	Month (a) (Note A)	Transmission (d) FF1, page 207 Col.(g) & pg. 206 Col. (b), ln 58	Transmission ARO (e) FF1, page 207 Col.(g) & pg. 206 Col. (b), ln 57	General (h) FF1, page 207 Col.(g) & pg. 206 Col. (b), ln 99	General ARO (i) FF1, page 207 Col.(g) & pg. 206 Col. (b), ln 98	Intangible (j) FF1, page 205 Col.(g) & pg. 204 Col. (b), ln 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					
14	Average of the 13 Monthly Balances	-	-	-	-	-

		Accumulated Depreciation				
Line No	Month (a) (Note A)	Transmission (d) FF1, page 219, ln 25, Col. (b)	Transmission ARO (e) Company Records (Included in total in Column (d))	General (h) FF1, page 219, ln 28, Col. (b)	General ARO (i) Company Records (Included in total in Column (h))	Intangible (j) FF1, page 200, ln 21, 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					
28	Average of the 13 Monthly Balances	-	-	-	-	-

Line No	Month (a) (Note A)	OATT Ancillary Services (GSU) Plant In Service (b) Company Records (included in total in column (d) of gross plant above)	OATT Ancillary Services (GSU) Accumulated Depreciation (c) Company Records (included in total in column (d) of accumulated depreciation above)	Excluded Plant - Plant In Service (d) Company Records (included in total in column (d) of line 14, Gross Plant, above)	Excluded Plant - Accumulated Depreciation (e) Company Records (included in total in column (d) of line 28, Accumulated Depreciation, 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	December of Rate Year				-
42	Average of the 13 Monthly				

Balances	-	-	-	-

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

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

46					-
47					-
48					-
49					-
50					-
51	Total Regulatory Deferrals Included in Ratebase		-	-	-

Unfunded Reserves Summary (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

AEP _______________ TRANSMISSION COMPANY

Line Number	(A) Description	(B) Source	(C) Balance @ December 31,	(D) Balance @ December 31,	(E) Average Balance 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	FF1, p. 276 - 277, ln 9, Col. (k)			-
13	Less: ARO Related Deferrals	WS B-1 - Actual Stmt. AF Ln. 13 (Note 1)			-
14	Less: Other Excluded Deferrals	WS B-1 - Actual Stmt. AF Ln. 12 (Note 1)			-
15	Transmission Related Deferrals	Ln 12 - ln 13 - ln 14	-	-	-
16	**Account 190**				
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	Less: Other Excluded Deferrals	WS B-2 - Actual Stmt. AG Ln. 3 (Note 1)			-
20	Transmission Related Deferrals	Ln 17 - ln 18 - ln 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)			-

NOTE 1 On this worksheet, "Company Records" refers to AEP's tax forecast and accounting ledger. The PRTR will use projected ending balances and reflect proration required by IRS Letter Rule Section 1.167(I)-I(h)(6)(ii). Line item detail of actual deferred tax items will be included on Worksheets B-1 and B-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

	COLUMN A	COLUMN B	COLUMN C	COLUMN D	COLUMN E	COLUMN F	COLUMN G	COLUMN H	COLUMN I	COLUMN J	COLUMN K	COLUMN L	COLUMN M	COLUMN N	COLUMN O
		PER BOOKS		NON-APPLICABLE/NON-UTILITY		(DEBIT) CREDIT AVERAGE	FUNCTIONALIZATION AVERAGE			FUNCTIONALIZATION 12/31/2016			FUNCTIONALIZATION 12/31/2017		
	ACCUMULATED DEFERRED FIT ITEMS	BALANCE AS OF 12-31-2016	BALANCE AS OF 12-31-2017	BALANCE AS OF 12-31-2016	BALANCE AS OF 12-31-2017	ELECTRIC UTILITY (B+C+D+E)/2	GENERATION	TRANSMISSION	DISTRIBUTION	GENERATION	TRANSMISSION	DISTRIBUTION	GENERATION	TRANSMISSION	DISTRIBUTION
1.00	ACCOUNT 281:														
2.01															
2.02		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									
3	TOTAL ACCOUNT 281	0	0	0	0	0	0	0	0	0	0	0	0	0	0
4	ACCOUNT 281 - ARO-Related 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						

5.06	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
5.25	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	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	
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	
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														
16	REFUNCTIONALIZED BASED ON JURISDICTIONAL PLANT														
17	NOTE: POST 1970 ACCUMULATED DEFERRED INV TAX CRED. (JDITC)														
18	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

	COLUMN A	COLUMN B	COLUMN C	COLUMN D	COLUMN E	COLUMN F	COLUMN G	COLUMN H	COLUMN I	COLUMN J	COLUMN K	COLUMN L	COLUMN M	COLUMN N	COLUMN O
		PER BOOKS		NON-APPLICABLE/NON-UTILITY		DEBIT (CREDIT) AVERAGE ELECTRIC UTILITY	FUNCTIONALIZATION AVERAGE			FUNCTIONALIZATION 12/31/2016			FUNCTIONALIZATION 12/31/2017		
	ACCUMULATED DEFERRED FIT ITEMS	BALANCE AS OF 12-31-2016	BALANCE AS OF 12-31-2017	BALANCE AS OF 12-31-2016	BALANCE AS OF 12-31-2017	(B+C+D+E) /2	GENERATION	TRANSMISSION	DISTRIBUTION	GENERATION	TRANSMISSION	DISTRIBUTION	GENERATION	TRANSMISSION	DISTRIBUTION
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						
		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	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	0			

2.87															
2.88				0	0	0									
2.89				0	0	0									
2.90				0	0	0	0	0	0						
2.91		0	0			0	0	0	0						
3	TOTAL ACCOUNT 190	0	0	0	0	0	0	0	0	0	0	0	0	0	0
4	ACCOUNT 190 - ARO-Related Deferals	0	0	0	0	0	0	0	0	0	0	0	0	0	0

COMPANY NAME HERE
Worksheet B-3
Excess/ Deficient ADIT Worksheet
For Year Ended December 31, 20__
Debit/(Credit)

A	B	C	D	E	F	G	H
TOTAL COMPANY BALANCES							
Line No.	**Account (NOTE A)**	**Description of Account**	**Protected Unprotected**	**Tax Rate Change Act**	**Excess Balance at Remeasurement (NOTE C)**	**Amortization Methodology (NOTE D)**	**Amortization Period**
	Deferred Tax Account (NOTE B)						
1a							
1b							
1c							
1d							
1e							
1f							
1g							
1h							
1i							
1j	**NOTE E**						
	Regulatory Deferral Accounts						
2a	182.3	Regulatory Asset					
2b	254	Regulatory Liability					
2c	**NOTE E**						
3	Total For Accounting Entries (Sum of Lines 1a through 2_)				-		

I	J	K	L	M	N	O	P	Q	R
1/1/20__ Beginning Balances			Balance Sheet Entries		Tax Expense Entries		12/31/20__ Ending Balance		
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**	**Excess ADIT in Utility Deferrals**	**Reference**
							Sum of Cols (I) - (O)		
							-		
							-		
-	-	-	-	-	-	-	-	-	

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.

AEPTCo subsidiaries in PJM
Cost of Service Formula Rate Using Actual/Projected FF1 Balances
Worksheet C Supporting Working Capital Rate Base Adjustments
AEP _______________ TRANSMISSION COMPANY

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
				Materials & Supplies					
Line Number			**Source**	**Balance @ December 31,**	**Balance @ December 31,**	**Average Balance for**		`	
1									
2		Transmission Materials & Supplies	FF1, p. 227, ln 8, Col. (c) & (b)			-			
3		General Materials & Supplies	FF1, p. 227, ln 11, Col. (c) & (b)			-			
4		Stores Expense (Undistributed) – Account 163	FF1, p. 227, ln 16, Col. (c) & (b)	0	0	-			

Prepayment Balance Summary (Note 1)

Line			Average of YE Balance	Excludable Balances	100% Transmission Related	Transmission Plant Related	Transmission Labor Related	Total Included in Ratebase (E)+(F)+(G)
5								
6		Totals as of December 31,	0	0	0	0	0	0
7		Totals as of December 31,						
8		**Average Balance**	-	-	-	-	-	-

Prepayments Account 165 - Balance @ 12/31/

Line	Acc. No.	Description	___ YE Balance	Excludable Balances	100% Transmission Related	Transmission Plant Related	Transmission Labor Related	Total Included in Ratebase (E)+(F)+(G)	Explanation
9									
10				-		-		-	
11				-		-		-	
12				-			-	-	
13				-				-	
14				-			-	-	
15				-				-	
16				-				-	
17							-	-	
18				-				-	
19				-			-	-	
		Subtotal - Form 1, p 111.57.c	0	0	0	0	0	0	

Prepayments Account 165 - Balance @ 12/31/

Line	Acc. No.	Description	___ YE Balance	Excludable Balances	100% Transmission Related	Transmission Plant Related	Transmission Labor Related	Total Included in Ratebase (E)+(F)+(G)	Explanation
20									
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							

Note 1: 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 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).

AEPTCo subsidiaries in PJM
Cost of Service Formula Rate Using Actual/Projected FF1 Balances
Worksheet D Supporting IPP Credits
AEP _______________ TRANSMISSION COMPANY

Line Number	(A) Description	(B) ___
1	Net Funds from IPP Customers 12/31/___ (___ FORM 1, P269)	-
2	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)	-
Note 1	On this worksheet Company Records refers to AEP ___ TRANSMISSION COMPANY 's general ledger.	

AEPTCo subsidiaries in PJM

Cost of Service Formula Rate Using Actual/Projected FF1 Balances

Worksheet E Supporting Revenue Credits

AEP _______________ TRANSMISSION COMPANY

Line Number	Description	(a) Total Company	(b) Non-Transmission	(c) Transmission
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)	(F)
Line Number	**Item No.**	**Description**	**Expense**	**100% Non-Transmission**	**100% Transmission Specific**	**Explanation**
		Regulatory O&M Deferrals & Amortizations				
1			-			
2			-			
3	-		-			
4		**Total**	0			
		Detail of Account 561 Per FERC Form 1				
5						
6	FF1 p 321.85.b	561.1 - Load Dispatch - Reliability				
7	FF1 p 321.86.b	561.2 - Load Dispatch - Monitor & Operate Trans System				
8	FF1 p 321.87.b	561.3 - Load Dispatch - Trans Service & Scheduling				
9	FF1 p 321.88.b	561.4 - Scheduling, System Control & Dispatch				
10	FF1 p 321.89.b	561.5 - Reliability, Planning and Standards Development				
11	FF1 p 321.90.b	561.6 - Transmission Service Studies				
12	FF1 p 321.91.b	561.7 - Generation Interconnection Studies				
13	FF1 p 321.92.b	561.8 - Reliability, Planning and Standards Development Services				
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)**	-	-	-	

AEPTCo subsidiaries in PJM

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		

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

Line No.	(A) Account	(B) Total Company	(C) Property	(D) Labor	(E) Other	(F) 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					-	
17						-
18					-	
19					-	
20					-	
21						-
22						-
23	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 1 is shown on WS H-1.

Functional Property Tax Allocation

Line No.		Lines 24-58 Column (B) Deliberately Left Blank	Transmission	Lines 24-58 Column (D) Deliberately Left Blank	General	Total
24	Functionalized Net Plant (TCOS, Lns 33 thru 36)					
	________ JURISDICTION					
25	Percentage of Plant in ________ JURISDICTION					
26	Net Plant in ________ JURISDICTION (Ln 24 * Ln 25)					
27	Less: Net Value of Exempted Generation Plant					
28	Taxable Property Basis (Ln 26 - Ln 27)					
29	Relative Valuation Factor					
30	Weighted Net Plant (Ln 28 * Ln 29)					
31	General Plant Allocator (Ln 31 / (Total - General Plant))					
32	Functionalized General Plant (Ln 31 * General Plant)					
33	Weighted ________ JURISDICTION Plant (Ln 30 + 32)					
34	Functional Percentage (Ln 33/Total Ln 33)					
35	Net Plant in __________ JURISDICTION (Ln 24 - Ln 26)					
36	Less: Net Value of Exempted Generation Plant					
37	Taxable Property Basis (Ln 36 - Ln 37)					
38	Relative Valuation Factor					
39	Weighted Net Plant (Ln 37 * Ln 38)					
40	General Plant Allocator (Ln 39 / (Total - General Plant))					
41	Functionalized General Plant (Ln 41 * General Plant)					
42	Weighted __________ JURISDICTION Plant (Ln 39 + 41)					
43	Functional Percentage (Ln 42/Total Ln 42)					

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

Line No.	(A) Annual Tax Expenses by Type (Note 1)	(B) Total Company	(C) FERC FORM 1 Tie-Back	(D) FERC FORM 1 Reference
1	**Revenue Taxes**			
2	Gross Receipts Tax			P.263.1 ln 7 (i) P.263.2 ln 3 (i) P.263.2 ln 4 (i)

Line No.	(A) "Real Estate and Personal Propety Tax Detail Annual Tax Expenses by Type (Note 1)"	(B) Tax Year	(C) Total Comapny	(D) FERC FORM 1 Tie-Back	(E) FERC FORM 1 Reference	(F) Tax Year Factor (Note 2)	(G) Transmission Function (Note 2)
3	**Real Estate and Personal Property Taxes Total (Ln 4 + Ln 5 + Ln 6 + Ln 7)**						
4	Real and Personal Property -						
5	Real and Personal Property -						
6	Real and Personal Property -						
7	Real and Personal Property - Other Jurisdictions						

Line No.	(A) Annual Tax Expense by Type (Note 1)	(C) FERC FORM 1 Tie-Back	(D) FERC FORM 1 Reference
8	**Payroll Taxes**		
9	Federal Insurance Contribution (FICA)		P.263 ln 6 (i)
10	Federal Unemployment Tax		P.263 ln 9 (i)
11	State Unemployment Insurance		P.263.1 ln 23 (i) P.263.3 ln 16 (i)
12	Line Left Deliberately Blank		
13	State Severance Taxes		
14	**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	State Lic/Registration Fee		P.263.1 ln 15 (i) P.263.4 ln 21 (i)

19	Misc. State and Local Tax		P.263.1 ln 12 (i)
20	Sales & Use		P.263 ln 30 (i) P.263.3 ln 21 (i)
21	Federal Excise Tax		P.263 ln 13 (i) 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 assesed. 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

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

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

ROE w/o incentives (TCOS, ln 138)	11.49%
Project ROE Incentive Adder	
ROE with additional basis point incentive	

Determine R (cost of long term debt, cost of preferred stock and equity percentage is from the TCOS, lns 164 through166)

	%	Cost	Weighted cost
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%
		R =	0.000%

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

B. Determine Return using 'R' with hypothetical basis point ROE increase for Identified Projects.

Rate Base (TCOS, ln 58)	-
R (fom A. above)	0.000%
Return (Rate Base x R)	-

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

Return (from B. above)	-
Effective Tax Rate (TCOS, ln 97)	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 80)	-
Return (TCOS, ln 109)	-
Income Taxes (TCOS, ln 108)	-
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 & Amortization (TCOS, ln 83)	-
Annual Rev. Req, w/ Basis Point ROE increase, less Depreciation	-

C. Determine FCR with hypothetical basis point ROE increase.

Net Transmission Plant (TCOS, ln 33)	-
Annual Revenue Requirement, with Basis Point ROE increase	-
FCR with Basis Point increase in ROE	0.00%
Annual Rev. Req, w / Basis Point ROE increase, less Dep.	-
FCR with Basis Point ROE increase, less Depreciation	0.00%
FCR less Depreciation (TCOS, ln 10)	0.00%
Incremental FCR with Basis Point ROE increase, less Depreciation	0.00%

III. Calculation of Composite Depreciation Rate

Average Transmission Plant Balance for ___ TCOS, ln 19	-
Annual Depreciation and Amortization Expense(TCOS, ln 83)	-
Composite Depreciation Rate	0.00%
Depreciable Life for Composite Depreciation Rate	-
Average Life in Whole Years	-

Note 1: Until AEP___________TRANSMISSION COMPANY establishes Transmission plant in service the depreciation expense component of the carrying charge will be calculated as in the Operating Company formula approved in Docket No. ER08-1329. The calculation for AEP___________TRANSMISSION COMPANY is shown on Worksheet P.

TransCo 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. (e.g. ER10-925-000)

Current Projected Year ARR	-
Current Projected Year ARR w/ Incentive	-
Current Projected Year Incentive ARR	-

Project Description:

Details			
Investment		Current Year	
Service Year (yyyy)	0	ROE increase accepted by FERC (Basis Points)	-
Service Month (1-12)		FCR w/o incentives, less depreciation	0.00%
Useful life	-	FCR w incentives approved for these facilities, less dep.	0.00%
CIAC (Yes or No)	0	Annual Depreciation Expense	-

CUMULATIVE HISTORY OF PROJECTED ANNUAL REVENUE REQUIREMENTS:

CUMMULATIVE HISTORY OF PROJECTED ANNUAL REVENUE REQUIREMENTS: INPUT PROJECTED ARR (WITH & WITHOUT INCENTIVES) FROM EACH PRIOR YEAR

TEMPLATE BELOW TO MAINTAIN HISTORY OF PROJECTED ARRS OVER THE LIFE OF THE PROJECT.

Investment Year	Beginning Balance	Depreciation Expense	Ending Balance	RTEP Rev. Req't. w/o Incentives	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 **
0	-	-	-	-	-	$ -		
1	-	-	-	-	-	$ -		
2	-	-	-	-	-	$ -		
3	-	-	-	-	-	$ -		
4	-	-	-	-	-	$ -		
5	-	-	-	-	-	$ -		
6	-	-	-	-	-	$ -		
7	-	-	-	-	-	$ -		
8	-	-	-	-	-	$ -		
9	-	-	-	-	-	$ -		
10	-	-	-	-	-	$ -		
11	-	-	-	-	-	$ -		
12	-	-	-	-	-	$ -		
13	-	-	-	-	-	$ -		
14	-	-	-	-	-	$ -		
15	-	-	-	-	-	$ -		
16	-	-	-	-	-	$ -		
17	-	-	-	-	-	$ -		
18	-	-	-	-	-	$ -		
19	-	-	-	-	-	$ -		
20	-	-	-	-	-	$ -		
21	-	-	-	-	-	$ -		
22	-	-	-	-	-	$ -		
23	-	-	-	-	-	$ -		
24	-	-	-	-	-	$ -		
25	-	-	-	-	-	$ -		
26	-	-	-	-	-	$ -		
27	-	-	-	-	-	$ -		
28	-	-	-	-	-	$ -		
29	-	-	-	-	-	$ -		
30	-	-	-	-	-	$ -		
31	-	-	-	-	-	$ -		
32	-	-	-	-	-	$ -		
33	-	-	-	-	-	$ -		
34	-	-	-	-	-	$ -		
35	-	-	-	-	-	$ -		
36	-	-	-	-	-	$ -		
37	-	-	-	-	-	$ -		
38	-	-	-	-	-	$ -		
39	-	-	-	-	-	$ -		
40	-	-	-	-	-	$ -		
41	-	-	-	-	-	$ -		
42	-	-	-	-	-	$ -		
43	-	-	-	-	-	$ -		
44	-	-	-	-	-	$ -		
45	-	-	-	-	-	$ -		
46	-	-	-	-	-	$ -		
47	-	-	-	-	-	$ -		
48	-	-	-	-	-	$ -		
49	-	-	-	-	-	$ -		
50	-	-	-	-	-	$ -		
51	-	-	-	-	-	$ -		
52	-	-	-	-	-	$ -		
53	-	-	-	-	-	$ -		
54	-	-	-	-	-	$ -		
55	-	-	-	-	-	$ -		
56	-	-	-	-	-	$ -		
57	-	-	-	-	-	$ -		
58	-	-	-	-	-	$ -		
59	-	-	-	-	-	$ -		
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.

I. Calculate Return and Income Taxes with 0 basis point ROE increase for Projects Qualified for Regional Billing.

A. Determine 'R' with hypothetical 0 basis point increase in ROE for Identified Projects

ROE w/o incentives (TCOS, ln 138)	11.49 %
Project ROE Incentive Adder	0
ROE with additional 0 basis point incentive	

Determine R (cost of long term debt, cost of preferred stock and equity percentage is from the TCOS, lns 164 through 166)

	%	Cost	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%	11.490%
		R =	0.000%

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

B. Determine Return using 'R' with hypothetical 0 basis point ROE increase for Identified Projects.

Rate Base (TCOS, ln 58)	-
R (fom A. above)	0.000 %
Return (Rate Base x R)	-

C. Determine Income Taxes using Return with hypothetical 0 basis point ROE increase for Identified Projects.

Return (from B. above)	-
Effective Tax Rate (TCOS, ln 97)	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 0 basis point ROE increase.

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

Annual Revenue Requirement (TCOS, ln 1)	-
Lease Payments (TCOS, Ln 80)	-
Return (TCOS, ln 109)	-
Income Taxes (TCOS, ln 108)	-
Annual Revenue Requirement, Less Lease payments, Return and Taxes	-

B. Determine Annual Revenue Requirement with hypothetical 0 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 0 Basis Point ROE increase	-
Depreciation (TCOS, ln 83)	-
Annual Rev. Req, w/ 0 Basis Point ROE increase, less Depreciation	-

C. Determine FCR with hypothetical 0 basis point ROE increase.

Net Transmission Plant (TCOS, ln 33)	-
Annual Revenue Requirement, with 0 Basis Point ROE increase	-
FCR with 0 Basis Point increase in ROE	0.00%
Annual Rev. Req, w / 0 Basis Point ROE increase, less Dep.	-
FCR with 0 Basis Point ROE increase, less Depreciation	0.00%
FCR less Depreciation (TCOS, ln 10)	0.00%
Incremental FCR with 0 Basis Point ROE increase, less Depreciation	0.00%

III. Calculation of Composite Depreciation Rate

Average Transmission Plant Balance for_____ TCOS, ln 19	-
Annual Depreciation and Amortization Expense (TCOS, ln 83)	-
Composite Depreciation Rate	0.00%
Depreciable Life for Composite Depreciation Rate	-
Average Life in Whole Years	-

Note 1: Until AEP___________TRANSMISSION COMPANY establishes Transmission plant in service the depreciation expense component of the carrying charge will be calculated as in the Operating Company formula approved in Docket No. ER08-1329. The calculation for AEP___________TRANSMISSION COMPANY is shown on Worksheet P.

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. (e.g. ER10-925-000)

Project Description:

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

Details			
Investment	-	Current Year	
Service Year (yyyy)	0	ROE increase accepted by FERC (Basis Points)	-
Service Month (1-12)		FCR w/o incentives, less depreciation	0.00%
Useful life	-	FCR w/incentives approved for these facilities, less dep.	0.00%
CIAC (Yes or No)	0	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 ##
0	-	-	-	-	-	-	$ -
1	-	-	-	-	-	-	$ -
2	-	-	-	-	-	-	$ -
3	-	-	-	-	-	-	$ -
4	-	-	-	-	-	-	$ -
5	-	-	-	-	-	-	$ -
6	-	-	-	-	-	-	$ -
7	-	-	-	-	-	-	$ -
8	-	-	-	-	-	-	$ -
9	-	-	-	-	-	-	$ -
10	-	-	-	-	-	-	$ -
11	-	-	-	-	-	-	$ -
12	-	-	-	-	-	-	$ -
13	-	-	-	-	-	-	$ -
14	-	-	-	-	-	-	$ -
15	-	-	-	-	-	-	$ -
16	-	-	-	-	-	-	$ -
17	-	-	-	-	-	-	$ -
18	-	-	-	-	-	-	$ -
19	-	-	-	-	-	-	$ -
20	-	-	-	-	-	-	$ -
21	-	-	-	-	-	-	$ -
22	-	-	-	-	-	-	$ -
23	-	-	-	-	-	-	$ -
24	-	-	-	-	-	-	$ -
25	-	-	-	-	-	-	$ -
26	-	-	-	-	-	-	$ -
27	-	-	-	-	-	-	$ -
28	-	-	-	-	-	-	$ -
29	-	-	-	-	-	-	$ -
30	-	-	-	-	-	-	$ -
31	-	-	-	-	-	-	$ -
32	-	-	-	-	-	-	$ -
33	-	-	-	-	-	-	$ -
34	-	-	-	-	-	-	$ -
35	-	-	-	-	-	-	$ -
36	-	-	-	-	-	-	$ -
37	-	-	-	-	-	-	$ -
38	-	-	-	-	-	-	$ -
39	-	-	-	-	-	-	$ -
40	-	-	-	-	-	-	$ -
41	-	-	-	-	-	-	$ -
42	-	-	-	-	-	-	$ -
43	-	-	-	-	-	-	$ -
44	-	-	-	-	-	-	$ -
45	-	-	-	-	-	-	$ -
46	-	-	-	-	-	-	$ -
47	-	-	-	-	-	-	$ -
48	-	-	-	-	-	-	$ -
49	-	-	-	-	-	-	$ -
50	-	-	-	-	-	-	$ -
51	-	-	-	-	-	-	$ -
52	-	-	-	-	-	-	$ -
53	-	-	-	-	-	-	$ -
54	-	-	-	-	-	-	$ -
55	-	-	-	-	-	-	$ -
56	-	-	-	-	-	-	$ -
57	-	-	-	-	-	-	$ -
58	-	-	-	-	-	-	$ -
59	-	-	-	-	-	-	$ -
Project Totals		-			-	-	-

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 **
	$ -		$ -	$ -
	$ -		$ -	$ -
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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.

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 (a) (Note A)	Proprietary Capital (b) (FF1 112.16)	Less: Preferred Stock (c) (FF1 250-251)	Less Undistributed Sub Earnings (Acct 216.1) (d) (FF1 112.12)	Less AOCI (Acct 219.1) (e) (FF1 112.15)	Average Balance of Common Equity (f)=(b)-(c)-(d)-(e)
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					
Line No	Month	Bonds	Less: Reacquired Bonds	Acct 223 LT Advances from Assoc. Companies	Acct 224 Senior Unsecured Notes	Less: Fair Value Hedges	Gross Proceeds Outstanding Long-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)

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**						
30	Interest on Long Term Debt - Accts 221 - 224 (256-257.33.i)			-			
31	Less: Total Hedge Gain/Expense Accumulated from p 256-257, col. (i) of FERC Form 1 included in Ln 30 and shown in 43 below.			-			
32	Amort of Debt Discount & Expense - Acct 428 (117.63.c)			-			
33	Amort of Loss on Reacquired Debt - Acct 428.1 (117.64.c)			-			
34	Less: Amort of Premium on Debt - 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 GAINS/LOSSES TO BE EXCLUDED FROM TCOS

38 AEP WEST VIRGINIA TRANSMISSION COMPANY may not include costs (or gains) related to interest hedging activities.

	HEDGE AMOUNTS BY ISSUANCE (FROM p. 256-257 (i) of the FERC Form 1)	(Amortization of (Gain)/Loss for 2017	Remaining Unamortized Balance	Amortization Period Beginning	Ending
39					
40					
41					
42					
43	**Net (Gain)/Loss Hedge Amortization To Be Removed**	-	-	-	-

Development of Cost of Preferred Stock

44	Balance of Preferred Stock (Line 14 (c))	-
45	Dividends on Preferred Stock (Acct 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 respectivielly. 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)	(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		
7	AEP System PBOP expense per dollar of direct labor (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 (Ln 8 * Ln 9)		
11	Direct PBOP Expense per Actuarial Report		
12	Additional PBOP Ledger Entry (From Company Records)		
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 ACCT.	RATES 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

	PLANT ACCT.	RATES Note 1
TRANSMISSION PLANT		
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	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: 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

	PLANT ACCT.	RATES 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 & 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	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 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

Line		Appalachian Power Company	Indiana Michigan Power Company	Kentucky Power Company	Kingsport Power Company	Ohio Power Company	Wheeling Power Company	AEP East Operating Companies' Consolidated Capital Structure
	Development of Long Term Debt Balances at Year End							
1	Bonds (112.18.c&d)							
2	Less: Reacquired Bonds (112.19.c&d)							
3	LT Advances from Assoc. Companies (112.20.c&d)							
4	Senior Unsecured Notes (112.21.c&d) Excludes Spent Nuc Fuel Disp Fund							
5	Less: Fair Value Hedges (See Note on Ln 7 below)							
6	**Total Long Term Debt Balance**							
7	NOTE: 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 Long Term Debt Interest Expense							
8	Interest on Long Term Debt (256-257.33.i)							
9	Amort of Debt Discount & Expense (117.63.c)							
10	Amort of Loss on Reacquired Debt (117.64.c)							
11	Less: Amort of Premium on Debt (117.65.c)							
12	Less: Amort of Gain on Reacquired Debt (117.66.c)							
13	Less: Hedge Interest on pp 256-257(i)							
14	LTD Interest Expense							
	Development of Cost of Preferred Stock and Preferred Dividends							
15	Dividend Rate (p. 250-251. 7.a)							
16	Par Value (p. 250-251. 8.c)							
17	Shares Outstanding (p.250-251. 8.e)							
18	Monetary Value (Ln 16 * Ln 17)							
19	Dividend Amount (Ln 15 * Ln 18)							
20	Dividend Rate (p. 250-251. 7.a)							
21	Par Value (p. 250-251. 8.c)							
22	Shares Outstanding (p.250-251. 8.e)							
23	Monetary Value (Ln 21 * Ln 22)							
24	Dividend Amount (Ln 20 * Ln 23)							
25	Dividend Rate (p. 250-251. 7.a)							
26	Par Value (p. 250-251. 8.c)							
27	Shares Outstanding (p.250-251. 8.e)							
28	Monetary Value (Ln 26 * Ln 27)							
29	Dividend Amount (Ln 25 * Ln 28)							
30	Dividend Rate (p. 250-251. 7.a)							
31	Par Value (p. 250-251. 8.c)							
32	Shares Outstanding (p.250-251. 8.e)							
33	Monetary Value (Ln 31 * Ln 32)							
34	Dividend Amount (Ln 30 * Ln 33)							
35	**Preferred Stock (Lns 18, 23, 28,33)**							
36	**Preferred Dividends (Lns 19, 24, 29,34)**							
	Development of Common Equity							
37	Proprietary Capital (112.16.c)							
38	Less: Preferred Stock (Ln 35 Above)							
39	Less: Account 216.1 (112.12.c)							
40	Less: Account 219.1 (112.15.c)							
41	**Balance of Common Equity**							
	Calculation of Capital Shares							
42	Long Term Debt (Ln 6 Above)							
43	Preferred Stock (Ln 35 Above)							
44	Common Equity (Ln 41 Above)							
45	Total Company Structure							
46	LTD Capital Shares (Ln 42 / Ln 45)							
47	Preferred Stock Capital Shares (Ln 43 / Ln 45)							
48	Common Equity Capital Shares (Ln 44 / Ln 45)							
49	**RESERVED**							
50	Reserved							
51	Reserved							
52	Reserved							
	Calculation of Capital Cost Rate							
53	LTD Capital Cost Rate (Ln 14 / Ln 6)							
54	Preferred Stock Capital Cost Rate (Ln 36 / Ln 35)							
55	Common Equity Capital Cost Rate	11.49%	11.49%	11.49%	11.49%	11.49%	11.49%	11.49%
	Calculation of Weighted Capital Cost Rate							
56	LTD Weighted Capital Cost Rate (Ln 46 * Ln 53)							
57	Preferred Stock Capital Cost Rate (Ln 47 * Ln 54)							
58	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

Line		Appalachian Power Company		Indiana Michigan Power Company	Kentucky Power Company	Kingsport Power Company	Ohio Power Company	Wheeling Power Company	AEP East Operating Companies' Consolidated Capital Structure
	Development of Long Term Debt Balances at Year End								
60	Bonds (112.18.c&d)								
61	Less: Reacquired Bonds (112.19.c&d)								
62	LT Advances from Assoc. Companies (112.20.c&d)								
63	Senior Unsecured Notes (112.21.c&d) Excludes Spent Nuc Fuel Disp Fund								
64	Less: Fair Value Hedges (See Note on Ln 66 below)								
65	**Total Long Term Debt Balance**								
66	NOTE: 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, Column H of the FF1)								
	Development 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								
	Development of Cost of Preferred Stock and Preferred Dividends								
74	Dividend Rate (p. 250-251. 7.a)								
75	Par Value (p. 250-251. 8.c)								
76	Shares Outstanding (p.250-251. 8.e)								
77	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. 8.c)								
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)**								
	Development of Common Equity								
96	Proprietary Capital (112.16.c)								
97	Less: Preferred Stock (Ln 94 Above)								
98	Less: Account 216.1 (112.12.c)								
99	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 Capital Shares (Ln 103 / Ln 104)								
108	**RESERVED**								
109	**RESERVED**								
110	**RESERVED**								
111	**RESERVED**								
	Calculation of Capital Cost Rate								
112	LTD Capital Cost Rate (Ln 73 / Ln 65)								
113	Preferred Stock Capital Cost Rate (Ln 95 / Ln 94)								
114	Common Equity Capital Cost Rate	11.49%	11.49%	11.49%	11.49%	11.49%	11.49%	11.49%	11.49%
	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)								
117	Common Equity Capital Cost Rate (Ln 107 * Ln 114)								
118	**Total Company Structure**								

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

Line		Appalachian Power Company	Indiana Michigan Power Company	~~Kentucky Power Company~~	Kingsport Power Company	Ohio Power Company	Wheeling Power Company	AEP East Operating Companies' Consolidated Capital Structure
	Development of Average Long Term Debt							
119	Average Bonds (Ln 1 + Ln 60) / 2							
120	Less: Average Reacquired Bonds (Ln 2 + Ln 61) / 2							
121	Average LT Advances from Assoc. Companies (Ln 3 + Ln 62) / 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**							
125	NOTE: 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, Column H of the FF1)							
	Development 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**							
	Cost of Preferred Stock and Preferred Dividends							
133	Average Balance of Preferred Stock (Ln 35 + Ln 94) / 2							
134	Preferred Dividends (Ln 36)							
	Development 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**							
	Calculation 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)							
145	Average Balance of Preferred Stock Capital Shares (Ln 141 / Ln 143)							
146	Average Balance of Common Equity Capital Shares (Ln 142 / Ln 143)							
147	**Reserved**							
148	**Reserved**							
149	**Reserved**							
150	**Reserved**							
	Calculation 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%
	Calculation 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**							

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	Average Monthly Interest Rate	Months	Calculated Interest	Amortization	Surcharge (Refund) Owed
Interest Rate on Amount of Refunds or Surcharges (Note 1)			0.2780%				

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

Calculation of Interest					**Monthly**		
January	Year 2018	-	0.2780%	12	-		-
February	Year 2018	-	0.2780%	11	-		-
March	Year 2018	-	0.2780%	10	-		-
April	Year 2018	-	0.2780%	9	-		-
May	Year 2018	-	0.2780%	8	-		-
June	Year 2018	-	0.2780%	7	-		-
July	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		
January through December	Year 2019	-	0.2780%	12	-		-

Over (Under) Recovery Plus Interest Amortized and Recovered Over 12 Months					**Monthly**		
January	Year 2020	-	0.2780%		-	-	-
February	Year 2020	-	0.2780%		-	-	-
March	Year 2020	-	0.2780%		-	-	-
April	Year 2020	-	0.2780%		-	-	-
May	Year 2020	-	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					-	
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.

Clean Att. H-20

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.

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[1] 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 Parties[2] 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;

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

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[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

D. 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.

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[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 Year[4] 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 credtited 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

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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;

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 True-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. <u>Annual Review Procedures</u>

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.

g. 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 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. <u>Resolution of Challenges</u>

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

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 Plant In Service				
Line No	Month (a) (Note A)	Transmission (d) FF1, page 207 Col.(g) & pg. 206 Col. (b), ln 58	Transmission ARO (e) FF1, page 207 Col.(g) & pg. 206 Col. (b), ln 57	General (h) FF1, page 207 Col.(g) & pg. 206 Col. (b), ln 99	General ARO (i) FF1, page 207 Col.(g) & pg. 206 Col. (b), ln 98	Intangible (j) FF1, page 205 Col.(g) & pg. 204 Col. (b), ln 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					
14	Average of the 13 Monthly Balances	-	-	-	-	-

		Accumulated Depreciation				
Line No	Month (a) (Note A)	Transmission (d) FF1, page 219, ln 25, Col. (b)	Transmission ARO (e) Company Records (Included in total in Column (d))	General (h) FF1, page 219, ln 28, Col. (b)	General ARO (i) Company Records (Included in total in Column (h))	Intangible (j) FF1, page 200, ln 21, 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					
28	Average of the 13 Monthly Balances	-	-	-	-	-

Line No	Month	OATT Ancillary Services (GSU) Plant In Service	OATT Ancillary Services (GSU) Accumulated Depreciation	Excluded Plant - Plant In Service	Excluded Plant - Accumulated Depreciation
	(a)	(b)	(c)	(d)	(e)
	(Note A)	Company Records (included in total in column (d) of gross plant above)	Company Records (included in total in column (d) of accumulated depreciation above)	Company Records (included in total in column (d) of line 14, Gross Plant, above)	Company Records (included in total in column (d) of line 28, Accumulated Depreciation, 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	December of Rate Year				-
42	Average of the 13 Monthly				

	Balances	-	-	-	-

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

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

46					-
47					-
48					-
49					-
50					-
51	Total Regulatory Deferrals Included in Ratebase		-	-	-

Unfunded Reserves Summary (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

AEP ______________ TRANSMISSION COMPANY

Line Number	(A) Description	(B) Source	(C) Balance @ December 31,	(D) Balance @ December 31,	(E) Average Balance 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	FF1, p. 276 - 277, ln 9, Col. (k)			-
13	Less: ARO Related Deferrals	WS B-1 - Actual Stmt. AF Ln. 13 (Note 1)			-
14	Less: Other Excluded Deferrals	WS B-1 - Actual Stmt. AF Ln. 12 (Note 1)			-
15	Transmission Related Deferrals	Ln 12 - ln 13 - ln 14	-	-	-
16	**Account 190**				
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	Less: Other Excluded Deferrals	WS B-2 - Actual Stmt. AG Ln. 3 (Note 1)			-
20	Transmission Related Deferrals	Ln 17 - ln 18 - ln 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)			-

NOTE 1 On this worksheet, "Company Records" refers to AEP's tax forecast and accounting ledger. The PRTR will use projected ending balances and reflect proration required by IRS Letter Rule Section 1.167(I)-I(h)(6)(ii). Line item detail of actual deferred tax items will be included on Worksheets B-1 and B-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

	COLUMN A	COLUMN B	COLUMN C	COLUMN D	COLUMN E	COLUMN F	COLUMN G	COLUMN H	COLUMN I	COLUMN J	COLUMN K	COLUMN L	COLUMN M	COLUMN N	COLUMN O
		PER BOOKS		NON-APPLICABLE/NON-UTILITY		(DEBIT) CREDIT AVERAGE	FUNCTIONALIZATION AVERAGE			FUNCTIONALIZATION 12/31/2016			FUNCTIONALIZATION 12/31/2017		
	ACCUMULATED DEFERRED FIT ITEMS	BALANCE AS OF 12-31-2016	BALANCE AS OF 12-31-2017	BALANCE AS OF 12-31-2016	BALANCE AS OF 12-31-2017	ELECTRIC UTILITY (B+C+D+E)/2	GENERATION	TRANSMISSION	DISTRIBUTION	GENERATION	TRANSMISSION	DISTRIBUTION	GENERATION	TRANSMISSION	DISTRIBUTION
1.00	ACCOUNT 281:														
2.01															
2.02		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									
3	TOTAL ACCOUNT 281	0	0	0	0	0	0	0	0	0	0	0	0	0	0
4	ACCOUNT 281 - ARO-Related 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						
5.06		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
5.25	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	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		
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		
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														
16	REFUNCTIONALIZED BASED ON JURISDICTIONAL PLANT														
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

	COLUMN A	COLUMN B	COLUMN C	COLUMN D	COLUMN E	COLUMN F	COLUMN G	COLUMN H	COLUMN I	COLUMN J	COLUMN K	COLUMN L	COLUMN M	COLUMN N	COLUMN O
		PER BOOKS		NON-APPLICABLE/NON-UTILITY		DEBIT (CREDIT) AVERAGE ELECTRIC UTILITY	FUNCTIONALIZATION AVERAGE			FUNCTIONALIZATION 12/31/2016			FUNCTIONALIZATION 12/31/2017		
	ACCUMULATED DEFERRED FIT ITEMS	BALANCE AS OF 12-31-2016	BALANCE AS OF 12-31-2017	BALANCE AS OF 12-31-2016	BALANCE AS OF 12-31-2017	(B+C+D+E) /2	GENERATION	TRANSMISSION	DISTRIBUTION	GENERATION	TRANSMISSION	DISTRIBUTION	GENERATION	TRANSMISSION	DISTRIBUTION
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						
		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			
2.87			0	0	0			
			0	0	0			

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

COMPANY NAME HERE
Worksheet B-3
Excess/ Deficient ADIT Worksheet
For Year Ended December 31, 20__
Debit/(Credit)

A	B	C	D	E	F	G	H
TOTAL COMPANY BALANCES							
Line No.	**Account (NOTE A)**	**Description of Account**	**Protected Unprotected**	**Tax Rate Change Act**	**Excess Balance at Remeasurement (NOTE C)**	**Amortization Methodology (NOTE D)**	**Amortization Period**
	Deferred Tax Account (NOTE B)						
1a							
1b							
1c							
1d							
1e							
1f							
1g							
1h							
1i							
1j	**NOTE E**						
	Regulatory Deferral Accounts						
2a	182.3	Regulatory Asset					
2b	254	Regulatory Liability					
2c	**NOTE E**						
3	Total For Accounting Entries (Sum of Lines 1a through 2_)				-		

I	J	K	L	M	N	O	P	Q	R
1/1/20__ Beginning Balances			Balance Sheet Entries		Tax Expense Entries		12/31/20__ Ending Balance		
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**	**Excess ADIT in Utility Deferrals**	**Reference**
							Sum of Cols (I) - (O)		
							-		
							-		
-	-	-	-	-	-	-	-	-	

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.

AEPTCo subsidiaries in PJM
Cost of Service Formula Rate Using Actual/Projected FF1 Balances
Worksheet C Supporting Working Capital Rate Base Adjustments
AEP _______________ TRANSMISSION COMPANY

Line Number	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
				Materials & Supplies					
			Source	Balance @ December 31,	Balance @ December 31,	Average Balance for			
1									
2		Transmission Materials & Supplies	FF1, p. 227, ln 8, Col. (c) & (b)			-			
3		General Materials & Supplies	FF1, p. 227, ln 11, Col. (c) & (b)			-			
4		Stores Expense (Undistributed) – Account 163	FF1, p. 227, ln 16, Col. (c) & (b)	0	0	-			
				Prepayment Balance Summary (Note 1)					
5			Average of YE Balance	Excludable Balances	100% Transmission Related	Transmission Plant Related	Transmission Labor Related	Total Included in Ratebase (E)+(F)+(G)	
6		Totals as of December 31,	0	0	0	0	0	0	
7		Totals as of December 31,							
8		**Average Balance**	-	-	-	-	-	-	
				Prepayments Account 165 - Balance @ 12/31/					
9	Acc. No.	Description	YE Balance	Excludable Balances	100% Transmission Related	Transmission Plant Related	Transmission Labor Related	Total Included in Ratebase (E)+(F)+(G)	Explanation
10				-		-		-	
11				-		-		-	
12				-			-	-	
13				-				-	
14				-			-	-	
15				-				-	
16				-				-	
17							-	-	
18				-				-	
19				-			-	-	
		Subtotal - Form 1, p 111.57.c	0	0	0	0	0	0	
				Prepayments Account 165 - Balance @ 12/31/					
20	Acc. No.	Description	YE Balance	Excludable Balances	100% Transmission Related	Transmission Plant Related	Transmission Labor Related	Total Included in Ratebase (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							

Note 1: 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 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).

AEPTCo subsidiaries in PJM
Cost of Service Formula Rate Using Actual/Projected FF1 Balances
Worksheet D Supporting IPP Credits
AEP _______________ TRANSMISSION COMPANY

Line Number	(A) Description	(B) ___
1	Net Funds from IPP Customers 12/31/___ (___ FORM 1, P269)	-
2	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)	-
Note 1	On this worksheet Company Records refers to AEP ___ TRANSMISSION COMPANY 's general ledger.	

AEPTCo subsidiaries in PJM

Cost of Service Formula Rate Using Actual/Projected FF1 Balances

Worksheet E Supporting Revenue Credits

AEP _______________ TRANSMISSION COMPANY

Line Number	Description	(a) Total Company	(b) Non-Transmission	(c) Transmission
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

Line Number	(A) Item No.	(B) Description	(C) Expense	(D) 100% Non-Transmission	(E) 100% Transmission Specific	(F) Explanation
		Regulatory O&M Deferrals & Amortizations				
1			-			
2			-			
3	-		-			
4		**Total**	0			
		Detail of Account 561 Per FERC Form 1				
5						
6	FF1 p 321.85.b	561.1 - Load Dispatch - Reliability				
7	FF1 p 321.86.b	561.2 - Load Dispatch - Monitor & Operate Trans System				
8	FF1 p 321.87.b	561.3 - Load Dispatch - Trans Service & Scheduling				
9	FF1 p 321.88.b	561.4 - Scheduling, System Control & Dispatch				
10	FF1 p 321.89.b	561.5 - Reliability, Planning and Standards Development				
11	FF1 p 321.90.b	561.6 - Transmission Service Studies				
12	FF1 p 321.91.b	561.7 - Generation Interconnection Studies				
13	FF1 p 321.92.b	561.8 - Reliability, Planning and Standards Development Services				
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)**	-	-	-	

AEPTCo subsidiaries in PJM
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	

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

Line No.	(A) Account	(B) Total Company	(C) Property	(D) Labor	(E) Other	(F) 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					-	
17						-
18					-	
19					-	
20					-	
21						-
22						-
23	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 1 is shown on WS H-1.

Functional Property Tax Allocation

Line No.		Lines 24-58 Column (B) Deliberately Left Blank	Transmission	Lines 24-58 Column (D) Deliberately Left Blank	General	Total
24	Functionalized Net Plant (TCOS, Lns 33 thru 36)					
	________ JURISDICTION					
25	Percentage of Plant in ________ JURISDICTION					
26	Net Plant in ________ JURISDICTION (Ln 24 * Ln 25)					
27	Less: Net Value of Exempted Generation Plant					
28	Taxable Property Basis (Ln 26 - Ln 27)					
29	Relative Valuation Factor					
30	Weighted Net Plant (Ln 28 * Ln 29)					
31	General Plant Allocator (Ln 31 / (Total - General Plant))					
32	Functionalized General Plant (Ln 31 * General Plant)					
33	Weighted ________ JURISDICTION Plant (Ln 30 + 32)					
34	Functional Percentage (Ln 33/Total Ln 33)					
35	Net Plant in __________ JURISDICTION (Ln 24 - Ln 26)					
36	Less: Net Value of Exempted Generation Plant					
37	Taxable Property Basis (Ln 36 - Ln 37)					
38	Relative Valuation Factor					
39	Weighted Net Plant (Ln 37 * Ln 38)					
40	General Plant Allocator (Ln 39 / (Total - General Plant))					
41	Functionalized General Plant (Ln 41 * General Plant)					
42	Weighted __________ JURISDICTION Plant (Ln 39 + 41)					
43	Functional Percentage (Ln 42/Total Ln 42)					

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

Line No.	(A) Annual Tax Expenses by Type (Note 1)	(B) Total Company	(C) FERC FORM 1 Tie-Back	(D) FERC FORM 1 Reference
1	**Revenue Taxes**			
2	Gross Receipts Tax			P.263.1 ln 7 (i) P.263.2 ln 3 (i) P.263.2 ln 4 (i)

Line No.	(A) "Real Estate and Personal Propety Tax Detail Annual Tax Expenses by Type (Note 1)"	(B) Tax Year	(C) Total Comapny	(D) FERC FORM 1 Tie-Back	(E) FERC FORM 1 Reference	(F) Tax Year Factor (Note 2)	(G) Transmission Function (Note 2)
3	**Real Estate and Personal Property Taxes Total (Ln 4 + Ln 5 + Ln 6 + Ln 7)**						
4	Real and Personal Property -						
5	Real and Personal Property -						
6	Real and Personal Property -						
7	Real and Personal Property - Other Jurisdictions						

Line No.	(A) Annual Tax Expense by Type (Note 1)	(C) FERC FORM 1 Tie-Back	(D) FERC FORM 1 Reference
8	**Payroll Taxes**		
9	Federal Insurance Contribution (FICA)		P.263 ln 6 (i)
10	Federal Unemployment Tax		P.263 ln 9 (i)
11	State Unemployment Insurance		P.263.1 ln 23 (i) P.263.3 ln 16 (i)
12	Line Left Deliberately Blank		
13	State Severance Taxes		
14	**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	State Lic/Registration Fee		P.263.1 ln 15 (i) P.263.4 ln 21 (i)
19	Misc. State and Local Tax		P.263.1 ln 12 (i)

20	Sales & Use		P.263 ln 30 (i) P.263.3 ln 21 (i)
21	Federal Excise Tax		P.263 ln 13 (i) 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 assesed. 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

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

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

ROE w/o incentives (TCOS, ln 138)				11.49%
Project ROE Incentive Adder				
ROE with additional basis point incentive				
Determine R (cost of long term debt, cost of preferred stock and equity percentage is from the TCOS, lns 164 through166)				
	%	Cost		Weighted cost
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%
			R =	0.000%

B. Determine Return using 'R' with hypothetical basis point ROE increase for Identified Projects.

Rate Base (TCOS, ln 58)	-
R (fom A. above)	0.000%
Return (Rate Base x R)	-

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

Return (from B. above)	-
Effective Tax Rate (TCOS, ln 97)	0.00%
Income Tax Calculation (Return x CIT)	-
ITC Adjustment	-
Excess Deferred Income Tax	-
Tax Affect of Permanent Differences	-
Income Taxes	-

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

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 80)	-
Return (TCOS, ln 109)	-
Income Taxes (TCOS, ln 108)	-
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 & Amortization (TCOS, ln 83)	-
Annual Rev. Req, w/ Basis Point ROE increase, less Depreciation	-

C. Determine FCR with hypothetical basis point ROE increase.

Net Transmission Plant (TCOS, ln 33)	-
Annual Revenue Requirement, with Basis Point ROE increase	-
FCR with Basis Point increase in ROE	0.00%
Annual Rev. Req, w / Basis Point ROE increase, less Dep.	-
FCR with Basis Point ROE increase, less Depreciation	0.00%
FCR less Depreciation (TCOS, ln 10)	0.00%
Incremental FCR with Basis Point ROE increase, less Depreciation	0.00%

II
I. Calculation of Composite Depreciation Rate

Average Transmission Plant Balance for ___ TCOS, ln 19	-
Annual Depreciation and Amortization Expense(TCOS, ln 83)	-
Composite Depreciation Rate	0.00%
Depreciable Life for Composite Depreciation Rate	-
Average Life in Whole Years	-

Note 1: Until AEP___________TRANSMISSION COMPANY establishes Transmission plant in service the depreciation expense component of the carrying charge will be calculated as in the Operating Company formula approved in Docket No. ER08-1329. The calculation for AEP___________TRANSMISSION COMPANY is shown on Worksheet P.

TransCo 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. (e.g. ER10-925-000)

Project Description:

Current Projected Year ARR	-
Current Projected Year ARR w/ Incentive	-
Current Projected Year Incentive ARR	-

Details			
Investment		Current Year	
Service Year (yyyy)	0	ROE increase accepted by FERC (Basis Points)	-
Service Month (1-12)		FCR w/o incentives, less depreciation	0.00%
		FCR w incentives approved for these facilities, less dep.	0.00%
Useful life	-		
CIAC (Yes or No)	0	Annual Depreciation Expense	-

CUMULATIVE HISTORY OF PROJECTED ANNUAL REVENUE REQUIREMENTS:

CUMMULATIVE HISTORY OF PROJECTED ANNUAL REVENUE REQUIREMENTS:
INPUT PROJECTED ARR (WITH & WITHOUT INCENTIVES) FROM EACH PRIOR YEAR

TEMPLATE BELOW TO MAINTAIN HISTORY OF PROJECTED ARRS OVER THE LIFE OF THE PROJECT.

Investment Year	Beginning Balance	Depreciation Expense	Ending Balance	RTEP Rev. Req't. w/o Incentives	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 **
0	-	-	-	-	-	$ -		
1	-	-	-	-	-	$ -		
2	-	-	-	-	-	$ -		
3	-	-	-	-	-	$ -		
4	-	-	-	-	-	$ -		
5	-	-	-	-	-	$ -		
6	-	-	-	-	-	$ -		
7	-	-	-	-	-	$ -		
8	-	-	-	-	-	$ -		
9	-	-	-	-	-	$ -		
10	-	-	-	-	-	$ -		
11	-	-	-	-	-	$ -		
12	-	-	-	-	-	$ -		
13	-	-	-	-	-	$ -		
14	-	-	-	-	-	$ -		
15	-	-	-	-	-	$ -		
16	-	-	-	-	-	$ -		
17	-	-	-	-	-	$ -		
18	-	-	-	-	-	$ -		
19	-	-	-	-	-	$ -		
20	-	-	-	-	-	$ -		
21	-	-	-	-	-	$ -		
22	-	-	-	-	-	$ -		
23	-	-	-	-	-	$ -		
24	-	-	-	-	-	$ -		
25	-	-	-	-	-	$ -		
26	-	-	-	-	-	$ -		
27	-	-	-	-	-	$ -		
28	-	-	-	-	-	$ -		
29	-	-	-	-	-	$ -		
30	-	-	-	-	-	$ -		
31	-	-	-	-	-	$ -		
32	-	-	-	-	-	$ -		
33	-	-	-	-	-	$ -		
34	-	-	-	-	-	$ -		
35	-	-	-	-	-	$ -		
36	-	-	-	-	-	$ -		
37	-	-	-	-	-	$ -		
38	-	-	-	-	-	$ -		
39	-	-	-	-	-	$ -		
40	-	-	-	-	-	$ -		
41	-	-	-	-	-	$ -		
42	-	-	-	-	-	$ -		
43	-	-	-	-	-	$ -		
44	-	-	-	-	-	$ -		
45	-	-	-	-	-	$ -		
46	-	-	-	-	-	$ -		
47	-	-	-	-	-	$ -		
48	-	-	-	-	-	$ -		
49	-	-	-	-	-	$ -		
50	-	-	-	-	-	$ -		
51	-	-	-	-	-	$ -		
52	-	-	-	-	-	$ -		
53	-	-	-	-	-	$ -		
54	-	-	-	-	-	$ -		
55	-	-	-	-	-	$ -		
56	-	-	-	-	-	$ -		
57	-	-	-	-	-	$ -		
58	-	-	-	-	-	$ -		
59	-	-	-	-	-	$ -		
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.

I. Calculate Return and Income Taxes with 0 basis point ROE increase for Projects Qualified for Regional Billing.

A. Determine 'R' with hypothetical 0 basis point increase in ROE for Identified Projects

ROE w/o incentives (TCOS, ln 138)	11.49 %
Project ROE Incentive Adder	0
ROE with additional 0 basis point incentive	

Determine R (cost of long term debt, cost of preferred stock and equity percentage is from the TCOS, lns 164 through 166)

	%	Cost	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%	11.490%
		R =	0.000%

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

B. Determine Return using 'R' with hypothetical 0 basis point ROE increase for Identified Projects.

Rate Base (TCOS, ln 58)	-
R (fom A. above)	0.000 %
Return (Rate Base x R)	-

C. Determine Income Taxes using Return with hypothetical 0 basis point ROE increase for Identified Projects.

Return (from B. above)	-
Effective Tax Rate (TCOS, ln 97)	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 0 basis point ROE increase.

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

Annual Revenue Requirement (TCOS, ln 1)	-
Lease Payments (TCOS, Ln 80)	-
Return (TCOS, ln 109)	-
Income Taxes (TCOS, ln 108)	-
Annual Revenue Requirement, Less Lease payments, Return and Taxes	-

B. Determine Annual Revenue Requirement with hypothetical 0 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 0 Basis Point ROE increase	-
Depreciation (TCOS, ln 83)	-
Annual Rev. Req, w/ 0 Basis Point ROE increase, less Depreciation	-

C. Determine FCR with hypothetical 0 basis point ROE increase.

Net Transmission Plant (TCOS, ln 33)	-
Annual Revenue Requirement, with 0 Basis Point ROE increase	-
FCR with 0 Basis Point increase in ROE	0.00%
Annual Rev. Req, w / 0 Basis Point ROE increase, less Dep.	-
FCR with 0 Basis Point ROE increase, less Depreciation	0.00%
FCR less Depreciation (TCOS, ln 10)	0.00%
Incremental FCR with 0 Basis Point ROE increase, less Depreciation	0.00%

III. Calculation of Composite Depreciation Rate

Average Transmission Plant Balance for_____ TCOS, ln 19	-
Annual Depreciation and Amortization Expense (TCOS, ln 83)	-
Composite Depreciation Rate	0.00%
Depreciable Life for Composite Depreciation Rate	-
Average Life in Whole Years	-

Note 1: Until AEP___________TRANSMISSION COMPANY establishes Transmission plant in service the depreciation expense component of the carrying charge will be calculated as in the Operating Company formula approved in Docket No. ER08-1329. The calculation for AEP___________TRANSMISSION COMPANY is shown on Worksheet P.

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. (e.g. ER10-925-000)

Project Description:

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

Details			
Investment	-	Current Year	
Service Year (yyyy)	0	ROE increase accepted by FERC (Basis Points)	-
Service Month (1-12)		FCR w/o incentives, less depreciation	0.00%
		FCR w/incentives approved for these facilities, less dep.	0.00%
Useful life	-		
CIAC (Yes or No)	0	Annual Depreciation Expense	-

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.

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 ##	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 **
0	-	-	-	-	-	-	$ -		$ -		$ -	$ -
1	-	-	-	-	-	-	$ -		$ -		$ -	$ -
2	-	-	-	-	-	-	$ -		$ -		$ -	$ -
3	-	-	-	-	-	-	$ -		$ -		$ -	$ -
4	-	-	-	-	-	-	$ -		$ -		$ -	$ -
5	-	-	-	-	-	-	$ -		$ -		$ -	$ -
6	-	-	-	-	-	-	$ -		$ -		$ -	$ -
7	-	-	-	-	-	-	$ -		$ -		$ -	$ -
8	-	-	-	-	-	-	$ -		$ -		$ -	$ -
9	-	-	-	-	-	-	$ -		$ -		$ -	$ -
10	-	-	-	-	-	-	$ -		$ -		$ -	$ -
11	-	-	-	-	-	-	$ -		$ -		$ -	$ -
12	-	-	-	-	-	-	$ -		$ -		$ -	$ -
13	-	-	-	-	-	-	$ -		$ -		$ -	$ -
14	-	-	-	-	-	-	$ -		$ -		$ -	$ -
15	-	-	-	-	-	-	$ -		$ -		$ -	$ -
16	-	-	-	-	-	-	$ -		$ -		$ -	$ -
17	-	-	-	-	-	-	$ -		$ -		$ -	$ -
18	-	-	-	-	-	-	$ -		$ -		$ -	$ -
19	-	-	-	-	-	-	$ -		$ -		$ -	$ -
20	-	-	-	-	-	-	$ -		$ -		$ -	$ -
21	-	-	-	-	-	-	$ -		$ -		$ -	$ -
22	-	-	-	-	-	-	$ -		$ -		$ -	$ -
23	-	-	-	-	-	-	$ -		$ -		$ -	$ -
24	-	-	-	-	-	-	$ -		$ -		$ -	$ -
25	-	-	-	-	-	-	$ -		$ -		$ -	$ -
26	-	-	-	-	-	-	$ -		$ -		$ -	$ -
27	-	-	-	-	-	-	$ -		$ -		$ -	$ -
28	-	-	-	-	-	-	$ -		$ -		$ -	$ -
29	-	-	-	-	-	-	$ -		$ -		$ -	$ -
30	-	-	-	-	-	-	$ -		$ -		$ -	$ -
31	-	-	-	-	-	-	$ -		$ -		$ -	$ -
32	-	-	-	-	-	-	$ -		$ -		$ -	$ -
33	-	-	-	-	-	-	$ -		$ -		$ -	$ -
34	-	-	-	-	-	-	$ -		$ -		$ -	$ -
35	-	-	-	-	-	-	$ -		$ -		$ -	$ -
36	-	-	-	-	-	-	$ -		$ -		$ -	$ -
37	-	-	-	-	-	-	$ -		$ -		$ -	$ -
38	-	-	-	-	-	-	$ -		$ -		$ -	$ -
39	-	-	-	-	-	-	$ -		$ -		$ -	$ -
40	-	-	-	-	-	-	$ -		$ -		$ -	$ -
41	-	-	-	-	-	-	$ -		$ -		$ -	$ -
42	-	-	-	-	-	-	$ -		$ -		$ -	$ -
43	-	-	-	-	-	-	$ -		$ -		$ -	$ -
44	-	-	-	-	-	-	$ -		$ -		$ -	$ -
45	-	-	-	-	-	-	$ -		$ -		$ -	$ -
46	-	-	-	-	-	-	$ -		$ -		$ -	$ -
47	-	-	-	-	-	-	$ -		$ -		$ -	$ -
48	-	-	-	-	-	-	$ -		$ -		$ -	$ -
49	-	-	-	-	-	-	$ -		$ -		$ -	$ -
50	-	-	-	-	-	-	$ -		$ -		$ -	$ -
51	-	-	-	-	-	-	$ -		$ -		$ -	$ -
52	-	-	-	-	-	-	$ -		$ -		$ -	$ -
53	-	-	-	-	-	-	$ -		$ -		$ -	$ -
54	-	-	-	-	-	-	$ -		$ -		$ -	$ -
55	-	-	-	-	-	-	$ -		$ -		$ -	$ -
56	-	-	-	-	-	-	$ -		$ -		$ -	$ -
57	-	-	-	-	-	-	$ -		$ -		$ -	$ -
58	-	-	-	-	-	-	$ -		$ -		$ -	$ -
59	-	-	-	-	-	-	$ -		$ -		$ -	$ -
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.

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

Line No	Month (a) (Note A)	Average Balance of Common Equity: Proprietary Capital (b) (FF1 112.16)	Less: Preferred Stock (c) (FF1 250-251)	Less Undistributed Sub Earnings (Acct 216.1) (d) (FF1 112.12)	Less AOCI (Acct 219.1) (e) (FF1 112.15)	Average Balance of Common Equity (f)=(b)-(c)-(d)-(e)
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	-	-	-	-	-

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

(Note A)	(FF1 112.18)	(FF1 112.19)	(FF1 112.20)	(FF1 112.21)	FF1, page 257, Col. (h) - Note 1	(c)+(d)+(e) -(f)
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**						
30	Interest on Long Term Debt - Accts 221 - 224 (256-257.33.i)			-			
31	Less: Total Hedge Gain/Expense Accumulated from p 256-257, col. (i) of FERC Form 1 included in Ln 30 and shown in 43 below.			-			
32	Amort of Debt Discount & Expense - Acct 428 (117.63.c)			-			
33	Amort of Loss on Reacquired Debt - Acct 428.1 (117.64.c)			-			
34	Less: Amort of Premium on Debt - 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 GAINS/LOSSES TO BE EXCLUDED FROM TCOS

38 AEP WEST VIRGINIA TRANSMISSION COMPANY may not include costs (or gains) related to interest hedging activities.

	HEDGE AMOUNTS BY ISSUANCE (FROM p. 256-257 (i) of the FERC Form 1)	(Amortization of (Gain)/Loss for 2017	Remaining Unamortized Balance	Amortization Period Beginning	Amortization Period Ending
39					
40					
41					
42					
43	**Net (Gain)/Loss Hedge Amortization To Be Removed**	-	-	-	-

Development of Cost of Preferred Stock

44	Balance of Preferred Stock (Line 14 (c))	-	
45	Dividends on Preferred Stock (Acct 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 respectivielу. 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)	(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		
7	AEP System PBOP expense per dollar of direct labor (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 (Ln 8 * Ln 9)		
11	Direct PBOP Expense per Actuarial Report		
12	Additional PBOP Ledger Entry (From Company Records)		
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 ACCT.	RATES 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

	PLANT ACCT.	RATES Note 1
TRANSMISSION PLANT		
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	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: 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

	PLANT ACCT.	RATES 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 & 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	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 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

Line		Appalachian Power Company	Indiana Michigan Power Company	Kentucky Power Company	Kingsport Power Company	Ohio Power Company	Wheeling Power Company	AEP East Operating Companies' Consolidated Capital Structure
	Development of Long Term Debt Balances at Year End							
1	Bonds (112.18.c&d)							
2	Less: Reacquired Bonds (112.19.c&d)							
3	LT Advances from Assoc. Companies (112.20.c&d)							
4	Senior Unsecured Notes (112.21.c&d) Excludes Spent Nuc Fuel Disp Fund							
5	Less: Fair Value Hedges (See Note on Ln 7 below)							
6	**Total Long Term Debt Balance**							
7	NOTE: 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 Long Term Debt Interest Expense							
8	Interest on Long Term Debt (256-257.33.i)							
9	Amort of Debt Discount & Expense (117.63.c)							
10	Amort of Loss on Reacquired Debt (117.64.c)							
11	Less: Amort of Premium on Debt (117.65.c)							
12	Less: Amort of Gain on Reacquired Debt (117.66.c)							
13	Less: Hedge Interest on pp 256-257(i)							
14	LTD Interest Expense							
	Development of Cost of Preferred Stock and Preferred Dividends							
15	Dividend Rate (p. 250-251. 7.a)							
16	Par Value (p. 250-251. 8.c)							
17	Shares Outstanding (p.250-251. 8.e)							
18	Monetary Value (Ln 16 * Ln 17)							
19	Dividend Amount (Ln 15 * Ln 18)							
20	Dividend Rate (p. 250-251. 7.a)							
21	Par Value (p. 250-251. 8.c)							
22	Shares Outstanding (p.250-251. 8.e)							
23	Monetary Value (Ln 21 * Ln 22)							
24	Dividend Amount (Ln 20 * Ln 23)							
25	Dividend Rate (p. 250-251. 7.a)							
26	Par Value (p. 250-251. 8.c)							
27	Shares Outstanding (p.250-251. 8.e)							
28	Monetary Value (Ln 26 * Ln 27)							
29	Dividend Amount (Ln 25 * Ln 28)							
30	Dividend Rate (p. 250-251. 7.a)							
31	Par Value (p. 250-251. 8.c)							
32	Shares Outstanding (p.250-251. 8.e)							
33	Monetary Value (Ln 31 * Ln 32)							
34	Dividend Amount (Ln 30 * Ln 33)							
35	**Preferred Stock (Lns 18, 23, 28,33)**							
36	**Preferred Dividends (Lns 19, 24, 29,34)**							
	Development of Common Equity							
37	Proprietary Capital (112.16.c)							
38	Less: Preferred Stock (Ln 35 Above)							
39	Less: Account 216.1 (112.12.c)							
40	Less: Account 219.1 (112.15.c)							
41	**Balance of Common Equity**							
	Calculation of Capital Shares							
42	Long Term Debt (Ln 6 Above)							
43	Preferred Stock (Ln 35 Above)							
44	Common Equity (Ln 41 Above)							
45	Total Company Structure							
46	LTD Capital Shares (Ln 42 / Ln 45)							
47	Preferred Stock Capital Shares (Ln 43 / Ln 45)							
48	Common Equity Capital Shares (Ln 44 / Ln 45)							
49	**RESERVED**							
50	Reserved							
51	Reserved							
52	Reserved							
	Calculation of Capital Cost Rate							
53	LTD Capital Cost Rate (Ln 14 / Ln 6)							
54	Preferred Stock Capital Cost Rate (Ln 36 / Ln 35)							
55	Common Equity Capital Cost Rate	11.49%	11.49%	11.49%	11.49%	11.49%	11.49%	11.49%
	Calculation of Weighted Capital Cost Rate							
56	LTD Weighted Capital Cost Rate (Ln 46 * Ln 53)							
57	Preferred Stock Capital Cost Rate (Ln 47 * Ln 54)							
58	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

Line		Appalachian Power Company		Indiana Michigan Power Company	Kentucky Power Company	Kingsport Power Company	Ohio Power Company	Wheeling Power Company	AEP East Operating Companies' Consolidated Capital Structure
	Development of Long Term Debt Balances at Year End								
60	Bonds (112.18.c&d)								
61	Less: Reacquired Bonds (112.19.c&d)								
62	LT Advances from Assoc. Companies (112.20.c&d)								
63	Senior Unsecured Notes (112.21.c&d) Excludes Spent Nuc Fuel Disp Fund								
64	Less: Fair Value Hedges (See Note on Ln 66 below)								
65	**Total Long Term Debt Balance**								
66	NOTE: 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, Column H of the FF1)								
	Development 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								
	Development of Cost of Preferred Stock and Preferred Dividends								
74	Dividend Rate (p. 250-251. 7.a)								
75	Par Value (p. 250-251. 8.c)								
76	Shares Outstanding (p.250-251. 8.e)								
77	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. 8.c)								
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)**								
	Development of Common Equity								
96	Proprietary Capital (112.16.c)								
97	Less: Preferred Stock (Ln 94 Above)								
98	Less: Account 216.1 (112.12.c)								
99	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 Capital Shares (Ln 103 / Ln 104)								
108	**RESERVED**								
109	**RESERVED**								
110	**RESERVED**								
111	**RESERVED**								
	Calculation of Capital Cost Rate								
112	LTD Capital Cost Rate (Ln 73 / Ln 65)								
113	Preferred Stock Capital Cost Rate (Ln 95 / Ln 94)								
114	Common Equity Capital Cost Rate	11.49%	11.49%	11.49%	11.49%	11.49%	11.49%	11.49%	11.49%
	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)								
117	Common Equity Capital Cost Rate (Ln 107 * Ln 114)								
118	**Total Company Structure**								

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

Line		Appalachian Power Company	Indiana Michigan Power Company		Kingsport Power Company	Ohio Power Company	Wheeling Power Company	AEP East Operating Companies' Consolidated Capital Structure
	Development of Average Long Term Debt							
119	Average Bonds (Ln 1 + Ln 60) / 2							
120	Less: Average Reacquired Bonds (Ln 2 + Ln 61) / 2							
121	Average LT Advances from Assoc. Companies (Ln 3 + Ln 62) / 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**							
125	NOTE: 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, Column H of the FF1)							
	Development 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**							
	Cost of Preferred Stock and Preferred Dividends							
133	Average Balance of Preferred Stock (Ln 35 + Ln 94) / 2							
134	Preferred Dividends (Ln 36)							
	Development 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**							
	Calculation 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)							
145	Average Balance of Preferred Stock Capital Shares (Ln 141 / Ln 143)							
146	Average Balance of Common Equity Capital Shares (Ln 142 / Ln 143)							
147	**Reserved**							
148	**Reserved**							
149	**Reserved**							
150	**Reserved**							
	Calculation 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%
	Calculation 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**							

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	Average Monthly Interest Rate	Months	Calculated Interest	Amortization	Surcharge (Refund) Owed
Interest Rate on Amount of Refunds or Surcharges (Note 1)			0.2780%				

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

Calculation of Interest					**Monthly**		
January	Year 2018	-	0.2780%	12	-		-
February	Year 2018	-	0.2780%	11	-		-
March	Year 2018	-	0.2780%	10	-		-
April	Year 2018	-	0.2780%	9	-		-
May	Year 2018	-	0.2780%	8	-		-
June	Year 2018	-	0.2780%	7	-		-
July	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		
January through December	Year 2019	-	0.2780%	12	-		-
Over (Under) Recovery Plus Interest Amortized and Recovered Over 12 Months					**Monthly**		
January	Year 2020	-	0.2780%		-	-	-
February	Year 2020	-	0.2780%		-	-	-
March	Year 2020	-	0.2780%		-	-	-
April	Year 2020	-	0.2780%		-	-	-
May	Year 2020	-	0.2780%		-	-	-
June	Year 2020	-	0.2780%		-	-	-
July	Year	-	0.2780%		-	-	-

	2020					
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					-	
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

Line No.			AEP Annual Revenue Requirement	AEP Annual Revenue Requirement w/ KPCO	AEP Annual Revenue Difference	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.	**Network 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	LESS: REVENUE REQUIREMENTS INCLUDED IN LINE 1 FOR:										
5	RTEP UPGRADES (W/O INCENTIVES)	(TCOS Ln 5)	$41,500,452	$41,500,452	$0	$26,695,952	$5,322,411		$0	$9,365,691	$116,397
6	OTHER ZONAL UPGRADES (W/O INCENTIVES)	(Worksheet J)	$0	$0	$0	$0	$0		$0	$0	$0
7	SUBTOTAL		$41,500,452	$41,500,452	$0	$26,695,952	$5,322,411		$0	$9,365,691	$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	- MW						
14	Annual Point-to-Point Rate in $/MW - Year	(Ln 12 / Ln 13)	$46,853.55	$50,754.21	$3,900.65						
15	Monthly Point-to-Point Rate in $/MW - Month	(Ln 14 / 12)	$3,904.46	$4,229.52	$325.05						
16	Weekly Point-to-Point Rate in $/MW - Weekly	(Ln 14 / 52)	$901.03	$976.04	$75.01						
17	Daily On-Peak Point-to-Point Rate in $/MW - Day	(Ln 14 / 260)	$180.21	$195.21	$15.00						
18	Daily Off-Peak Point-to-Point Rate in $/MW - Day	(Ln 14 / 365)	$128.37	$139.05	$10.69						
19	Hourly On-Peak Point-to-Point Rate in $/MW - Hour	(Ln 14 / 4160)	$11.26	$12.20	$0.94						
20	Hourly Off-Peak Point-to-Point Rate in $/MW - Hour	(Ln 14 / 8760)	$5.35	$5.79	$0.45						
C.	**PJM Regional Service**										
21	RTEP UPGRADE ATRR W/O INCENTIVES	(Ln 7)	41,500,452	41,500,452	-	26,695,952	5,322,411		-	9,365,691	116,397
22	ADDITIONAL ATRR FOR FERC-APPROVED INCENTIVES ON RTEP	(Worksheet J)	-	-	-	-	-		-	-	-
23	TRUE-UP ADJUSTMENT INCLUDING INTEREST	(Worksheet Q)	6,432,945	6,432,945	-	5,263,827	470,168		-	697,095	1,855
24	**RTEP PTRR FOR PJM COLLECTION UNDER SCHEDULE 12**		**$ 47,933,397**	**$ 47,933,397**	**$ -**	31,959,779	5,792,580	-	-	10,062,786	118,252

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.	**Schedule 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 Dispatch Services (321.88.b)		$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 Development 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 - Ln 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						
10	AEP Zone Rate for Schedule 1A Service.	(Line 8 / Line 9)	-$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

Line No.			AEPTCo subsidiaries in PJM Annual Revenue Requirement	AEPTCo subsidiaries in PJM w/ KY Transco Annual Revenue Requirement	AEPTCo subsidiaries in PJM Difference Annual Revenue Requirement	APPALACHIAN TRANSMISSION COMPANY Annual Revenue Requirement	INDIANA MICHIGAN TRANSMISSION COMPANY Annual Revenue Requirement	KENTUCKY TRANSMISSION COMPANY Annual Revenue Requirement	OHIO TRANSMISSION COMPANY Annual Revenue Requirement	WEST VIRGINIA TRANSMISSION COMPANY Annual Revenue Requirement
A.	**Network Service**									
1	REVENUE REQUIREMENT (w/o incentives)	(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
2	LESS: REVENUE CREDITS	(TCOS Ln 2)	$14,546,000	$14,546,000	$0	$0	$1,729,000		$12,817,000	$0
3	CURRENT YEAR AEPTCo ANNUAL TRANSMISSION 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	$244,590,387
4	LESS: REVENUE REQUIREMENTS INCLUDED IN LINE 1 FOR:									
5	RTEP UPGRADES ATRR (W/O INCENTIVES)	(TCOS Ln 5)	$144,533,762	$149,646,973	$5,113,210	$0	$48,028,719		$44,875,793	$51,629,251
6	OTHER UPGRADES ATRR (W/O INCENTIVES)	(Worksheet J)	$0	$0	$0	$0	$0		$0	$0
7	SUBTOTAL		$144,533,762	$149,646,973	$5,113,210	$0	$48,028,719		$44,875,793	$51,629,251
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
9	INCREMENTAL APPROVED INCENTIVE PTRR	(Worksheet J)	$0	$0	$0	$0	$0		$0	$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
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
11a	Facility Credits under PJM OATT Section 30.9	(TCOS Ln 3)	$4,055,395	$4,055,395	$0				$4,055,395	
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**
B.	**Point-to-Point Service**									
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	$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	$0.08					
C.	**PJM Regional Service**									
21	RTEP UPGRADE PTRR W/O INCENTIVES	(Ln 7)	144,533,762	149,646,973	5,113,210	-	48,028,719		44,875,793	51,629,251
22	ADDITIONAL ATRR FOR FERC-APPROVED INCENTIVES ON RTEF	(Worksheet J)	-	-	-	-	-		-	-
23	TRUE-UP ADJUSTMENT INCLUDING INTEREST (2018)	(Worksheet R)	10,196,062	9,954,382	(241,680)	-	2,661,868		(2,436,143)	9,970,337
24	**RTEP PTRR FOR PJM COLLECTION UNDER SCHEDULE 12**		**$ 154,729,824**	**$ 159,601,355**	**$ 4,871,531**	-	50,690,586	-	42,439,650	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

Line No.			AEPTCo subsidiaries in PJM Annual Revenue Requirement	APPALACHIAN TRANSMISSION COMPANY Annual Revenue Requirement	INDIANA MICHIGAN TRANSMISSION COMPANY Annual Revenue Requirement	KENTUCKY TRANSMISSION COMPANY Annual Revenue Requirement	OHIO TRANSMISSION COMPANY Annual Revenue Requirement	WEST VIRGINIA TRANSMISSION COMPANY Annual Revenue Requirement
A.	**Schedule 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 Services (321.88.b)		$0	$0	$0	$0	$0	$0
3	Less: Load Disptach - Reliability, Planning & Standards Development 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
B.	**Schedule 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					