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November 22, 2016

Honorable Kimberly D Bose
Secretary
Federal Energy Regulatory Commission
888 First St., N.E.
Washington D.C. 20426

Re: American Electric Power Service Corporation
Docket No. ER17-405-000

Dear Secretary Bose:

Pursuant to Section 205 of the Federal Power Act, 16 U.S.C. Section 824(d), and Section 35.13 of the Federal Energy Regulatory Commission's ("FERC" or "Commission") regulations, American Electric Power Service Corporation ("AEPSC"), on behalf of its affiliates, Appalachian Power Company, Indiana Michigan Power Company, Kentucky Power Company, Kingsport Power Company ("KgPCo"), Ohio Power Company, and Wheeling Power Company (collectively referred to herein as "AEP East Operating Companies" or "AEP Companies") (AEPSC and the AEP East Operating Companies are collectively referred to herein as "AEP") submits for filing proposed revisions to the transmission formula rates and protocols of the AEP operating companies, Attachment H-14A and Attachment H-14B of the PJM Interconnection, L.L.C. ("PJM") Open Access Transmission Tariff ("PJM Tariff").

Through these proposed revisions, AEP seeks to: (1) transition its transmission formula rates from "historic" to "forward looking;" (2) add line items to pro-rate property-related accumulated deferred income tax ("ADIT") in the projected test year and provide flow through of deferred tax liability items; (3) update KgPCo depreciation rates to reflect those recently accepted by the Tennessee Regulatory Authority ("TRA"); and (4) add other revisions to its protocols and formula rate template to conform to recent Commission guidance and existing PJM Tariff provisions.

In addition to the overall changes to the formula rate protocols necessary to implement a forward-looking rate, AEP also proposes to update its formula rate protocols to reflect those recently accepted by the Commission.

Revised tariff sheets implementing the proposed changes are included as Attachments A-C. AEP respectfully requests that the Commission grant waiver of its prior notice requirements as necessary to accept the revised tariff sheets, effective January 1, 2017, with the revised rate becoming effective March 1, 2017.

I. Background

AEP's transmission facilities are available on an open access basis under the PJM Tariff. In Docket No. ER08-1329, AEP submitted for filing a formula rate and implementation protocols for the AEP pricing zone under Attachment H-14 of the PJM Tariff. The Commission accepted AEP's rate filing subject to hearing and settlement judge procedures and a compliance filing.[1] AEP and the intervening parties in Docket No. ER08-1329 ultimately settled all issues raised with respect to the formula rate, and the settlement was approved by the Commission on October 1, 2010 ("Settlement").[2] Attachment H-14B contains a formula rate for transmission service over AEP's facilities, which is updated annually.

Pursuant to the formula rate protocols set forth in Attachment H-14A of the PJM Tariff, on or before May 25 of each year, AEP is required to recalculate its annual transmission revenue requirements, producing the "Annual Updates" for the upcoming rate year, which AEP then submits as an informational filing with the Commission. Each of the Annual Updates produces transmission revenue requirements used to calculate the Network Integration Transmission Service, Point-to-Point, and Transmission Enhancement, and Scheduling, System Control and Dispatch Service rates under the PJM Tariff for transmission service in the AEP transmission zone. Each of the formula rates relies largely on prior year cost of service data as reported in the FERC Form No. 1 to develop the transmission revenue requirements. Thus, except for an end of year projection of net plant, the current formula rates are "historic looking" in that costs incurred during the previous year serve as a proxy for AEP's cost of providing transmission service during the rate year.

The use of historic data results in a significant recovery lag for transmission costs. For example, under the current formula rate, during the first six months of 2017, AEP's transmission rates would be based on its plant balances projected for the end of 2016 and other rate components based upon costs it incurred in 2015. In July 2017, the transmission rate would be updated utilizing a projected plant balance for the end of 2017, but the other cost components would be based upon calendar year 2016 financial and operational data. Thus, the recovery of costs incurred during any year will not begin for as many as 18 months after they were incurred. Cost recovery for a given rate year will not be completed for as long as 30 months. This lag is particularly problematic given that AEP is continuing to make significant investments in its transmission system,

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[1] *American Electric Power Service Corp.*, 124 FERC ¶ 61,306 (2008).

[2] *American Electric Power Service Corp.*, 133 FERC ¶ 61,007 (2010).

yet the transmission revenue requirements and resulting rates do not accurately reflect that investment. To alleviate this problem, and to ensure that transmission rates more accurately reflect the costs of transmission, AEP proposes revisions to Attachments H-14A and B to implement forward-looking formula rates.

In addition to the overall change to convert AEP's formula rates from primarily historic looking to forward looking, AEP proposes other changes to its formula rates. These changes are designed to bring AEP's formula rates in line with recent guidance concerning tax-related assets and requirements in the PJM Tariff as well as update KgPCo's depreciation rates to reflect those recently approved for KgPCo by the TRA .

II. Description and Justification of Proposed Changes

A. Revisions to Effectuate Forward-Looking Rate

Through this filing, AEP proposes revisions to each of its formula rate templates and protocols to transition the currently-effective historic looking formula rate to a forward-looking formula rate. Under the proposed revised formula, AEP will fully project its cost of service for the next calendar year. After the first year in which the proposed changes go into effect (which will utilize a truncated schedule as a transitional mechanism), AEP proposes to finalize its projection annually by October 31 with rates effective the following January 1. AEP will also calculate a true-up of its annual rates no later than May 25, consistent with its current true-up process. Additionally, the true-up charge or credit will be included in the rates effective January 1 of the following year.

The revisions will enable AEP to recover major transmission expenditures closer in time to their incurrence, improving cash flow, income recognition, and enabling AEP's rates to better match its costs of providing transmission service. At the same time, the current and continuing true-up will ensure that customers pay no more and no less than AEP's actual revenue requirement based on data reported in its annual FERC Form No. 1 reports. AEP proposes revisions to its formula rate template and protocols to effectuate these changes.

In addition to the overall benefit of reducing lag, the revised schedule for projecting cost of service and implementing the new rate is consistent with PJM's own billing processes. PJM utilizes each transmission customer's contribution to the Network Service Peak Load ("NSPL") -- which is the highest single-hour peak from the prior twelve months ending October 31 -- to bill transmission customers beginning January 1. AEP's current process does not modify the rates January 1 even though PJM updates each customer's billing demand on January 1. Thus, under the current formula rate, there is a mismatch between the AEP rate and the billing determinant used to apply the rate for the period January 1 through June 30 of each year. This can create a larger true up associated with network transmission service.

The timeline included in the proposed forward-looking formula rate will address this issue since the rates will be updated in October and go into effect on the following January 1. The AEP Companies will utilize their best estimate of the transmission peak using known data through August and potentially including September. Consequently, the January 1 rate will utilize a peak value that is expected to be identical or nearly identical to the peak utilized by PJM for the billing determinant. Therefore, the rate and the billing determinant will be consistent throughout the entire period to which the rate applies.

The Commission has previously accepted revisions to existing formula rates to convert them from historic to forward-looking. As the Commission has explained, "a forward-looking formula rate, if properly designed and supported . . . is a reasonable means to avoid lag in cost recovery."[3] The Commission has also explicitly acknowledged the value of a forward-looking rate where companies are undertaking significant transmission investment. According to the Commission, using forward-looking estimated costs is not a departure from ratemaking practice, and, even if rates may initially increase under a forward-looking approach, "customers will ultimately only pay the cost of service they would have paid on the lagging basis."[4]

Additionally, other transmission owners in PJM currently have forward-looking formula rates. These transmission owners include: American Transmission Systems, Inc., Public Service Electric and Gas Company, and Virginia Electric and Power Company. By transitioning to a forward-looking formula rate, AEP's revenue requirement methodology would be consistent with those of other PJM transmission owners.

To implement this change AEP respectfully requests that FERC accept the revised tariff sheets by December 31, 2016 with an effective date of January 1, 2017. Because this date is in the middle of the current rate year, AEP proposes to implement a transitional forward-looking rate beginning in January 2017. Pursuant to this transitional mechanism, AEP would prepare and file updated transmission revenue requirements and the resulting transmission rates by January 31, 2017 (based on a calendar 2017 projection), with the rates becoming effective on March 1, 2017. While the actual rates would not change until March 1, 2017, the actual tariff would be effective January 1, 2017, aligning the 2017 true-up process with the 2017 calendar year. After the updated revenue requirements are filed, but prior to the effective date of the rates, AEP would conduct a transmission customer webinar - February 2017. For the following rate year, 2018, AEP would file projected 2018 rates by October 31, 2017 to go into effect January 1, 2018. Subsequent rate years would continue on that calendar timeline.

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[3] *Midwest Indep. Transmission Sys. Operator, Inc.*, 141 FERC ¶ 61,121, at P 77 (2012) (approving forward looking formula rate for Ameren Services Co.).

[4] *International Transmission Company*, 116 FERC ¶ 61,036, at P 19 (2006) (citing *Boston Edison Co.*, 91 FERC ¶ 61,198 (2000)).

For true-ups that occurred prior to the effective date of the revised tariff sheets (January 1, 2017), AEP will compute its 2016 true-up using the existing formula rate[5] May 25, 2017 true-up date and include that true up in the revised rates that go into effect January 1, 2018. By May 25, 2018, AEP will file the 2017 true-up. That true-up will be pro-rated in the sense that any portion of 2017 prior to the effective date of the revised tariff sheets will be trued up utilizing the existing methodology. For the 2017 period from the effective date of the new tariff sheets through the end of 2017, the true up will be determined utilizing the revised tariff sheets. These pro-rated amounts will be combined into a total 2017 true-up and included in the rates effective January 1, 2019.

B. Revisions to Effectuate Tax-Related Changes

1. ADIT Adjustment Calculation

AEP also proposes changes to its formula rates to allow for the inclusion of an ADIT adjustment calculation that is similar to what other utilities have been granted,[6] and which are necessary in order to avoid any types of normalization violations which could end up significantly increasing rates in the future. A critical aspect of this proposed change allows for the inclusion of a proration calculation.

These changes are necessary in order to harmonize the current template with the specific computations the Internal Revenue Code requires in connection with projected test years. Specifically these changes are required to enable the correct determination of the maximum amount of ADIT that can be treated as a rate base reduction as it relates to utility property. These computations only apply to property, since only the deferred taxes on property are governed by the Internal Revenue Service ("IRS") normalization rules. Additionally, the proposed changes would enable these computations to recognize proration, in order to appropriately take into account the timing implications of the projected test year. Without proration, a calculation of deferred taxes would inappropriately result in what could be analogized to flowing-through a pending interest free loan to ratepayers. To prevent this result, the IRS issued a number of Private Letter Rulings ("PLRs") on this issue in the early 1990's, and more recently (i.e., during the past year) a number of similar PLRs have been issued specifically in connection with formula rate requests where a projected test period was used, as is requested here. The IRS's recent guidance mirrors the previous PLRs, and is consistent with the proposed changes to the formula rate plan.

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5 While the existing templates will be used to calculate the 2016 true-up, the 2016 KgPCo depreciation expense reported on the FERC Form No. 1 (also used as an input to the 2016 true-up) will reflect new KgPCo depreciation rates approved by the TRA as described in Section C of this letter.

6 *See, e.g.*, *Midcontinent Independent System Operator, Inc.*, 153 FERC ¶ 61,371 (2015); *Midcontinent Independent System Operator, Inc.*, 153 FERC ¶ 61,374 (2015); *MidAmerican Energy Co.*, Docket No. ER16-16, Letter Order (Dec. 30, 2015).

The consequences of violating IRS normalization rules would be severe. AEP would no longer be able to claim accelerated depreciation (including bonus depreciation) on tax returns. This would result in a significant loss of cash liquidity resulting from a significant reduction in the amount of ADIT that is recorded on its books. Without this cash liquidity, AEP would have to secure new loans as the ADIT balance unwinds and the current taxes are paid to the government. More importantly, the higher financing costs associated with the new loans combined with the reduction in ADIT (which would result in a much higher rate base) would result in higher electric utility rates for customers. In other words, AEP customers would no longer benefit from the reduced rate base caused by ADIT, resulting in increased revenue requirements and higher rates.

Consistent with recent Commission precedent, the proposed revisions are necessary to comport AEP's formula rate to recent IRS guidance which, in turn, ensures that AEP can continue to claim accelerated depreciation, which ultimately benefits customers.

2. Permanent Book/Tax Differences and Excess Deferred Income Taxes

Additionally, AEP proposes revisions to the formula rate to include a mechanism to allow the recovery of income taxes related to permanent differences, as well as the recovery of excess deferred income taxes. This change is appropriate because both permanent book/tax differences and excess deferred income taxes are components of a utility's income tax expense. There is no principled reason to exclude these items from the costs recovered in rates. Both of these items are included and recovered in all base rate case proceedings that the AEP operating companies currently file in various state jurisdictions.

Currently, the formula rate template does not include a mechanism to allow the recovery of income taxes related to either permanent differences or excess deferred income taxes. The proposed changes to the template correct this defect. Inclusion of these items in the template is appropriate, given that these items are no different from the amortization of investment tax credits (which are already included in the formula rate template), or from depreciation and operating expenses recoverable through rates.

In this regard, permanent Schedule M differences merit special mention. Unlike temporary differences (i.e., differences between the treatment of a particular amount on the company's books and the treatment of the same particular amount in the company's income tax return that are temporary in nature, and which, over time, disappear once the same amount is eventually included on the financial statements and tax returns), there are certain items of revenue and expense that are, over time, in fact treated differently for financial reporting purposes than for income tax purposes. These are referred to as permanent differences. Some examples of permanent differences include AFUDC-Equity and the cost of meals and entertainment.

Deferred income taxes are not recorded on permanent differences. In the case of the book depreciation related to AFUDC-Equity that has been capitalized in the property accounts, in the period reported, current income taxes will be adjusted to reflect the non-deductibility of these costs and there will be no deferred income taxes as such amounts will not "ever" be deducted on the tax return.

Of special note, excess deferred income taxes occur as the result of a change in the corporate tax law or tax rates which would increase or decrease the future tax liability of the company. GAAP requires that deferred income tax liabilities be recorded at the currently enacted regular income tax rate. If it is likely, as a result of action by a regulator, that the future increase or decrease in taxes payable due to the change in tax law or rates will be recovered from or returned to customers, the impact of the rate change is essentially “reserved” on the books to be returned to or recovered from the customers through rates as the temporary book/tax differences reverse.

Permanent book/tax differences and excess deferred income taxes are a component of a company’s income tax expense, and therefore are appropriately included and recovered in rates. Accordingly, AEP proposes changes to the formula rate template to provide a mechanism to allow the recovery of income taxes related to permanent differences or excess deferred income taxes. Notably, the Commission has accepted revisions to the formula rate templates of other transmission owners in PJM to address the recovery of deferred tax liability.[7]

C. KgPCo Depreciation Rates

The depreciation rates for KgPCo that generate the book expense included in the formula rate calculation in Attachment H-14 were set in 2007. KgPCo’s depreciation rates recently changed as a result of an order issued by the TRA in Docket No. 16-00001. The Depreciation Study Report and order accepting the underlying depreciation rates can be viewed at the following links:

Depreciation Study Report:
http://share.tn.gov/tra/orders/2016/1600001g.pdf - (KgPCo Exhibit No. 1 (JAC)

KgPSC Final Order in Docket No. 2016-00001:
http://share.tn.gov/tra/orders/2016/1600001fp.pdf

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[7] *See Duquesne Light Co.*, Docket No. ER13-1220, Letter Order (Apr. 26, 2013); *PPL Electric Utilities Corp.*, Docket No. ER12-1397-000, Letter Order (May 23, 2012).

AEP seeks Commission authorization to update the depreciation rate inputs in the proposed formula rate to reflect the new state-approved depreciation rates for KgPCo. The updated depreciation rates are set forth in Attachment D to this transmittal letter and reflected in a revised Worksheet - P – "Transmission Depreciation Rates Effective as of 09/1/2016 for Single Jurisdiction Companies Kingsport Power Company." The changes in depreciation rates will result in decreased annual transmission depreciation expenses for KgPCo. The depreciation rate for transmission plant decreased from 2.59% to 1.46%. The decrease was mainly due to an increase in the average service life for accounts 352, 353, 354, 355 and 356 and a decrease in the net salvage ratio for accounts 353 and 356. The decrease was partially offset by an increase in the net salvage ratio for accounts 352, 354 and 355. The annualized effect of the change in depreciation rates can be seen in the summaries of prior and new depreciation rates contained in Attachment D, page 6.

D. Other Conforming Revisions

In addition to updating the formula rate implementation protocols to reflect the transition from historic looking to forward looking, AEP proposes to overhaul the protocols to conform to recent Commission guidance in this area. In particular, the revised protocols are consistent with the Commission's guidance in the Midcontinent Independent System Operator, Inc. ("MISO") formula rate protocols proceedings.[8] Consistent with the Commission's instructions to other entities with forward-looking formula rates, the proposed revised protocols satisfy the Commission's concerns with respect to (i) scope of participation in the information exchange process; (ii) the transparency of the information exchange; and (iii) the ability of interested parties to challenge implementation of the formula rate as a result of the information exchange.[9]

Except as modified in this filing, the provisions of the settlement in FERC Docket No. ER08-1329 continue to apply to the implementation of the formula rate. AEP has added and edited certain template notes to reflect existing provisions.

AEP also proposes updates to its formula rate template to conform to the PJM Tariff, and redline versions showing the changes are submitted herewith.

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[8] The implementation protocols of the MISO transmission owners were the subject of a recent investigation by the Commission in Docket No. ER13-2379-000. The proposed revised protocols herein are consistent with the protocols filed by MISO and the MISO transmission owners in that docket as a part of their most recent February 13, 2015 compliance filing, which was accepted via letter order by the Commission on August 21, 2015. *See Midcontinent Indep. Sys. Operator, Inc.*, Letter from Penny S. Murrell, FERC, to Matthew R. Dorsett, MISO, Docket No. ER13-2379-004 (issued Aug. 21, 2015) (letter order accepting MISO compliance filing); *see also Midcontinent Indep. Sys. Operator, Inc.*, Compliance Filing Revising Attachment O Formula Rate Protocols, Docket No. ER13-2379-000 (filed Feb. 13, 2015).

[9] *See, e.g., Empire Dist. Elec. Co.*, 148 FERC ¶ 61,030 at P 6 (2014), *order on compliance filing*, 150 FERC ¶ 61,200 (2015).

III. Effective Date and Waiver Request

AEP seeks an effective date of January 1, 2017 for the proposed revisions to Attachment H-20, while the new rates would go into effect on March 1, 2017. AEP respectfully requests that the Commission grant any waivers necessary to permit this request.

IV. Contents of this Filing

This filing consists of the following documents:

a. This transmittal letter;
b. Revised Attachment H-14A in clean form (Attachment A);
c. Revised Attachment H-14A in redlined form (Attachment B);
d. Revised Attachment H-14B in clean form (Attachment C);
e. Revised Attachment H-14B in redlined form (Attachment D); and
f. A schedule setting forth prior and revised state approved depreciation expense for KgPCo (Attachment E).

Pursuant to Section 35.7 of the Commission's regulations,[10] the contents of this filing are being submitted as part of an XML filing package that conforms to the Commission's eTariff instructions.

V. Additional 35.13 Filing Requirements and Requests for Waivers

This filing is primarily intended to change the timing of the recovery of AEP's transmission costs and to conform AEP's formula rates to current guidance regarding treatment of tax assets and to existing provisions of the PJM Tariff. Consequently, to the extent necessary, AEP seeks waiver of the cost support information required by 18 C.F.R. §§ 35.13(b) and 35.13(c). However, AEP provides the following general information addressed by the Commission's rules.

[10] Pursuant to Order No. 714, this filing is submitted by PJM on behalf of AEPSC 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 this revised Attachments H-14A and H-14B in the eTariff system as part of PJM's electronic Intra PJM Tariff.

A. A list of documents submitted with the filing:

See Section IV.

B. The date on which the utility proposes to make the rate change effective:

AEP requests that the revised tariff provisions become effective January 1, 2017, with the rates going into effect March 1, 2017.

C. The names and addresses of persons to whom a copy of the rate change has been posted:

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. In accordance with the Commission's regulations,[11] 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[12] 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. Also, 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.

Additionally, copies of this filing are also being made available on AEP's website at: http://www.aep.com/about/codeofconduct/OASIS/TariffFilings/

D. A brief description of the rate change:

See Section II.

E. A statement of the reasons for the rate change:

See Sections I and II.

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11 *See* 18C.F.R §§ 35.2(e) and 385.2010(f)(3).

12 PJM already maintains, updates and regularly uses e-mail lists for all PJM members and affected state commissions.

F. A showing that all requisite agreement to the rate change, or to the filing of the rate change, including any agreement required by contract, has in fact been obtained:

No agreement to the rate change, or to the filing of the rate change, is required.

G. A statement showing any expenses or costs that have been alleged or judged in any administrative or judicial proceeding to be illegal, duplicative, or unnecessary costs that are demonstrably the product of discriminatory employment practices:

No such expenses or costs exist.

VI. Correspondence

Correspondence relating to this filing should be addressed to:

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VII. Conclusion

Wherefore, AEP respectfully requests that the Commission accept these revised tariff sheets, effective January 1, 2017, with the new rates going into effect on March 1, 2017, and grant any applicable waivers.

Respectfully submitted,

/s/ Amanda Riggs Conner

Amanda Riggs Conner
Senior Counsel
American Electric Power Service Corporation

Attachment A

Attachment H-14A in Clean Form

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

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

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

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

b. The posting of the Annual Projection shall:

(i) Provide the Formula Rate calculations and all inputs thereto, as well as supporting documentation and workpapers for data that are used in the projected Net Revenue Requirement;

(ii) Include all inputs in sufficient detail to identify the components of AEP's projected Net Revenue Requirement, explanations of the bases for the projections and input data, and sufficient detail and explanation to enable Interested 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.

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.

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

[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.

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. **True-Up Adjustment**

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 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 twenty-four (24) months during which the over or under recovery in the revenue requirement exists, i.e., January 1 of the Rate Year being trued-up through December 31 of the following year. The interest rate to be applied to the over-recovery or 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, or portion thereof, it is effective that first year. Similarly, the actual Net Revenue Requirement will be divided by 12 to calculate the actual 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.

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

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.

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]

(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;

[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. 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. Provided however, that 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. Provided however, that 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 an Informal 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 a given year's 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 reasonably and accurately calculated the Annual Update or Annual Projection and/or reasonably adopted and applied the Accounting Change. 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.

Attachment B

Attachment H-14A in Redlined Form

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.

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.

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

[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.

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. True-Up Adjustment

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 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 twenty-four (24) months during which the over or under recovery in the revenue requirement exists, i.e., January 1 of the Rate Year being trued-up through December 31 of the following year. The interest rate to be applied to the over-recovery or 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, or portion thereof, it is effective that first year. Similarly, the actual Net Revenue Requirement will be divided by 12 to calculate the actual 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.

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

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.

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]

(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;

[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. 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. Annual Review Procedures

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

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

b. In the event of a Preliminary Challenge, AEP will appoint a senior representative to work with the Interested Party (or its representatives) toward a resolution of the dispute.

c. AEP shall respond in writing to a Preliminary Challenge within twenty (20) business days of receipt, and its response shall notify the challenging party of the extent to which AEP agrees or disagrees with the challenge. If AEP disagrees with the Preliminary Challenge, it will provide the Interested Party with an explanation supporting the challenged inputs, explanations, allocations, calculations, or other information. AEP shall promptly cause to be posted its responses to all Preliminary Challenges at a publicly accessible location on PJM's internet website and OASIS, and a link to the website will be e-mailed to the PJM Exploder List. Provided however, that 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. Provided however, that 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 an Informal 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 a given year's 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 reasonably and accurately calculated the Annual Update or Annual Projection and/or reasonably adopted and applied the Accounting Change. 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.

~~FORMULA RATE IMPLEMENTATION PROTOCOLS~~
~~Definitions~~

~~"Annual Transmission Revenue Requirements" means the result produced by populating the Formula Rate Template with data as provided by the Formula Rate.~~

~~"Annual Update" means the posting and informational filing submitted by AEP on or before May 25 of each year that sets forth the AEP Zonal Transmission Cost of Service ("TCOS") for the subsequent Rate Year and which contains the True-Up calculation for the prior calendar year.~~

~~"Discovery Period" means the period after each annual Publication Date to serve information requests on AEP as provided in Section 2b below.~~

~~"First Rate Year" means the period of March 1, 2009 through June 30, 2009.~~

~~"Formal Challenge" means a challenge to an Annual Update submitted to the Federal Energy Regulatory Commission ("FERC") as provided in Section 3.a below.~~

~~"Formula Rate" means these Formula Rate Implementation Protocols (to be included as Attachment H-14A of the PJM Interconnection, L.L.C. ("PJM"), FERC Electric Tariff ("PJM Tariff")) and the Formula Rate Template.~~

~~"Formula Rate Template" means the collection of formulae, and worksheets, unpopulated with any data, to be included as Attachment H-14B of the PJM Tariff.~~

~~"Interested Party" means any person or entity having standing under Section 206 of the Federal Power Act ("FPA") with respect to the Annual Update.~~

~~"Material Changes" means (i) material changes in AEP's accounting policies and practices, (ii) changes in FERC's Uniform System of Accounts ("USofA"), (iii) changes in FERC Form No. 1 reporting requirements as applicable, or (iv) changes in the FERC's accounting policies and practices, which change causes a result under the Formula Rate different from the result under the Formula Rate as calculated without such change.~~

~~"Preliminary Challenge" means a written challenge to the Annual Update submitted to AEP as provided in Section 2.a below.~~

~~"Protocols" means these Formula Rate Implementation Protocols (to be included as Attachment H-14A of the PJM Tariff)~~

~~"Publication Date" means the date on which the Annual Update is posted under the provisions of Section 1.b below.~~

~~"Rate Year" means the twelve consecutive month period that begins on July 1 and continues through June 30 of the subsequent calendar year except for the First Rate Year.~~

~~"Review Period" means the period during which Interested Parties may review the calculations in the Annual Update as provided in Section 2.a below.~~

~~Section 1 Annual Updates~~[1]

~~a. Beginning March 1, 2009, the Annual Transmission Revenue Requirements applicable under Attachment H-14B and the Network Integration Transmission Service and Point-to-Point rates derived therefrom shall be applicable to services for the subsequent Rate Year.~~

~~b. On or before May 25 of each year, the AEP East Companies ("AEP") shall recalculate its Annual Transmission Revenue Requirements, producing the Annual Update for the upcoming Rate Year, and post such Annual Update on PJM's Internet website via a link to the Transmission Services page or a similar successor page ("Publication Date"). In addition, AEP shall submit such Annual Update as an informational filing with the FERC. AEP shall also send an e-mail or other similar electronic communication to all Interested Parties that have previously requested such notification through procedures to be established by AEP that informs the recipient that the Annual Update is available and that provides the Uniform Resource Locator or other similar identifying locator information from which the Annual Update can be obtained.~~

~~c. If the date for making the Annual Update posting/filing should fall on a weekend or a holiday recognized by the FERC, then the posting/filing shall be due on the next business day.~~

~~d. The date on which the last of the events listed in Section 1.b or 1.c occurs shall be that year's Publication Date.~~

~~[1] It is the intent of the Formula Rate, including the supporting explanations and allocations described therein, that each input to the Formula Rate Template 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. Where the reconciliation is provided through a worksheet included in the filed Formula Rate Template, the inputs to the worksheet must meet this transparency standard, and doing so will satisfy this transparency requirement for the amounts that are output from the worksheet and input to the main body of the Formula Rate Template. Appendix A to these Protocols summarizes the Cost of Service and Formula Rate Settlement Principles further describing the intent of the Parties and the Formula Rate.~~

~~e. The Annual Update shall include a "workable" Excel file or files containing the data-populated Formula Rate Template as well as supporting calculations and workpapers that demonstrate and explain information not otherwise set out in the FERC Form No. 1 reports of the AEP East Companies.~~

~~f. The Annual Update for the Rate Year:~~

~~(i) shall include a notice to Interested Parties that an open stakeholder meeting will be held, on a date specified in the notice that shall be no earlier than ten (10) business days from the date of posting of the Annual Update and no later than June 25, to discuss the Annual Update;~~

~~(ii) shall, to the extent specified in the Formula Rate, and except as provided in Section 1.h below, be based upon prudently incurred costs, the data for such prudently incurred costs to be taken from the FERC Form No. 1 reports of the AEP East Companies for the most recent calendar year, and be based upon the books and records of AEP, all of the foregoing data, books, and records maintained consistent with the USofA and FERC accounting policies, practices, and procedures;~~

~~(iii) shall populate, in accordance with the FERC's orders establishing generally applicable transmission ratemaking policies and with PJM Policies and the PJM OATT, the Formula Rate Template with the data identified in Section 1.f.(ii) above;~~

~~(iv) shall endeavor to include a summary of significant changes or events that, in the Company's view, might represent a notable change to the input data and formula rate results since March 1, 2009, or since the last Annual Update and that AEP implemented;~~

~~(v) shall be subject to challenge and review, true-up, and refunds or surcharges with interest in accordance with the procedures set forth in this Attachment H-14A; and~~

~~(vi) shall not seek to modify the Formula Rate and shall not be subject to challenge by seeking to modify the Formula Rate (*i.e.*, all such modifications to the Formula Rate — including return on equity and those elements noted in I.g.(i) below — will require, as applicable, an FPA Section 205 or Section 206 filing); provided however, AEP may be required by the FERC to modify the Formula Rate in response to a Formal Challenge if the circumstances set forth in Section 4 below apply.~~

~~g. Formula Rate inputs~~

~~(i) Stated inputs to the Formula Rate Template: for (i) rate of return on common equity; (ii) "Post-Employment benefits other than Pension" pursuant to Statement of Financial Accounting Standards No. 106, Employers' Accounting for Postretirement Benefits Other Than Pensions ("PBOP") charges;[2] (iii) depreciation and/or amortization rates; shall be stated values to be used in the rate formula until changed pursuant to an FPA Section 205 or 206 filing.[3]~~

~~(ii) Placeholders for future use: those parts of the Formula Rate that are required to be maintained at a value of zero as placeholders, including incentive rates, regulatory assets[4] (e.g., extraordinary property losses), regulatory liabilities and tax affected gains or losses on sales of land held for future use, shall remain at zero until changed pursuant to an FPA Section 205 or 206 filing.~~

~~(iii) Cost of Service elements recorded in accounts not specifically provided for in the Formula Rate: any cost, expense or other element of the cost of providing service not specifically provided for shall not be recoverable under the Formula Rate until filed for pursuant to FPA Section 205, accepted by the FERC and, if otherwise required, a determination has been made by the Chief Accountant regarding the journal entries for the transaction.~~

~~h. In addition to the above, for the calculation of the TCOS to become effective for the Rate Year that begins July 1 of the year during which the Annual Update is prepared, AEP shall populate the Formula Rate Template included in the Annual Update with estimated data for transmission plant-in-service and related depreciation, accumulated depreciation, return and income taxes projected to occur by the end of the calendar year during which the Annual Update is prepared, and the rates that become effective for the Rate Year that begins on July 1 of such year shall be based on the calculation of the Formula Rate including those costs, and the true-up adjustment ("True-Up") pursuant to Sections 1.i and 1.j, below.~~

~~2. The allowable amount of PBOP expense will be reviewed every four years, starting in 2012, to determine, based on a formula, whether it should continue at the current level for four more years or be changed to a different level for that period.~~

~~3. The present formula template does not include CWIP. In the event AEP proposes to include CWIP, it must make a Section 205 filing with the Commission.~~

~~4. See *American Electric Power Service Corp.*, 124 FERC ¶ 61,306 (2008) at PP 27-28~~

~~i. AEP shall also prepare and post, as part of the Annual Update, a true-up Transmission Cost Of Service ("True-Up TCOS") for the prior calendar year based on the Formula Rate and using the prior year FERC Form No.1 reports and other data, as specified above, excluding the estimated data described in Section 1.h. above.. The True-Up TCOS shall utilize a rate base that reflects the average of the cost of investments at the beginning and end of the prior year.~~

~~j. The difference between the True-Up TCOS for the prior calendar year, or applicable portion thereof, and the charges billed under the Formula Rate during that prior calendar year (excluding any True-Up related amounts), together with interest at the rate set generally pursuant to 18 C.F.R. § 35.19a shall be added to or subtracted from the Annual Update cost-of-service, as appropriate, to determine the net TCOS to be charged in the rates that become effective on July 1 each year.~~

~~Section 2 Annual Review Procedures~~

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

~~a. Interested Parties shall have up to one hundred fifty (150) days after the Publication Date ("Review Period") (unless such period is extended with the written consent of AEP) to review the calculations and to notify AEP in writing of any specific challenges, including challenges related to Material Changes, to the application of the Formula Rate in an Annual Update ("Preliminary Challenge").~~

~~b. Interested Parties shall have up to one hundred thirty-five (135) days after each annual Publication Date (unless such period is extended with the written consent of AEP) (the "Discovery Period") to serve reasonable information requests on AEP. Such information requests shall be limited to what is necessary to determine: (i) whether AEP has properly calculated the Annual Update under review (including any corrections pursuant to Section 4); (ii) whether AEP has correctly applied the Formula Rate including the procedures in this Attachment H-14A; and (iii) whether the inputs to the true-up and projected ATRR are correct, prudent, and otherwise appropriate costs and revenue credits. Interested Persons can make information requests regarding allocation methodologies, including inter-corporate cost allocation methodologies, used to derive the inputs.~~

~~c. AEP shall make a good faith effort to respond to information requests pertaining to the Annual Update within fifteen (15) business days of receipt of such requests. Notwithstanding anything to the contrary contained in these Protocols, with respect to any information requests received by AEP within the Discovery Period and for which AEP is unable to provide a response within fifteen (15) business days after the end of the Discovery Period, the Review Period shall be extended day-for-day until AEP's response is provided.~~

~~d. Preliminary or Formal Challenges related to Material Changes are not intended to serve as a means of pursuing other objections to the Formula Rate. Failure to make a~~

~~Preliminary Challenge or Formal Challenge with respect to an Annual Update shall preclude use of these procedures with respect to that Annual Update but shall not preclude a subsequent Preliminary Challenge or Formal Challenge related to a subsequent Annual Update to the extent such Challenge affects the subsequent Annual Update.~~

~~e. In any proceeding initiated to address a Preliminary or Formal Challenge or *sua sponte* by the FERC, a party or parties seeking to modify the Formula Rate in any respect shall bear the applicable burden under the FPA.~~

~~Section 3 Resolution of Challenges~~

~~a. If AEP and any Interested Party(ies) have not resolved any Preliminary Challenge to the Annual Update within twenty-one (21) days after the Review Period ends, an Interested Party shall have an additional twenty-one (21) days (unless such period is extended with the written consent of AEP to continue efforts to resolve the Preliminary Challenge) to submit a written Formal Challenge to the FERC, pursuant to 18 C.F.R. § 385.206, which shall be served on AEP by electronic service on the date of such filing ("Formal Challenge"). However, there shall be no need to make a Formal Challenge or to await conclusion of the time periods in Section 2 if the FERC already has initiated a proceeding to consider the Annual Update.~~

~~b. Parties shall make a good faith effort to raise all issues in a Preliminary Challenge prior to filing a Formal Challenge; provided, however, that a Preliminary Challenge shall not be a prerequisite for bringing a Formal Challenge. Failure to notify AEP East Companies of an issue with respect to an Annual Update shall not preclude an Interested Party from pursuing such issue in a Preliminary Challenge or Formal Challenge.~~

~~c. All information and correspondence produced pursuant to these Protocols may be included in any Formal Challenge, in any other proceeding concerning the Formula Rate initiated at the FERC pursuant to the FPA, or in any proceeding before the U.S. Court of Appeals to review a FERC decision.~~

~~d. Any response by AEP to a Formal Challenge must be submitted to the FERC within twenty (20) days of the date of the filing of the Formal Challenge, and shall be served on the filing party(ies) by electronic service on the date of such filing.~~

~~e. AEP shall bear the burden of proving that it has reasonably applied the terms of the Formula Rate, and the applicable procedures in these Formula Rate Implementation Protocols, and of proving that it has properly calculated the challenged Annual Update pursuant to the Formula Rate, and of proving it has reasonably adopted and applied any Material Changes in that year's Annual Update. These Protocols are to be interpreted consistent with P 36 of the Commission's Order Accepting And Suspending Formula Rate Subject To Refund And Establishing Hearing And Settlement Judge Procedures[5] with respect to burden of proof in establishing the justness and reasonableness of the charge in any Formal Challenge and in any proceeding initiated by FERC in response to a Formal Challenge.~~

~~f. These Protocols in no way limit the rights of AEP or any Interested Party to initiate a proceeding at the FERC at any time with respect to the Formula Rate or any Annual Update consistent with the party's full rights under the FPA, including Sections 205, 206 and 306, and the FERC's regulations.~~

~~g. It is recognized that resolution of Formal Challenges concerning Material Changes may necessitate adjustments to the Formula Rate input data for the applicable Annual Update, including any True-Up, or changes to the Formula Rate Template to ensure that the Formula Rate continues to operate in a manner that is just, reasonable, and not unduly discriminatory or preferential.~~

~~Section 4 Changes to Annual Informational Filings~~

~~a. Notice. If any changes are required to be made to the Annual Update, whether because of changes made under these Protocols, due to revisions made to a prior year's FERC Form No. 1 report of an AEP East Company, or input data used for a Rate Year or calendar year that would have affected the Annual Update for that Rate Year or calendar year, or as the result of any FERC proceeding to consider a prior year's Annual Update, AEP shall promptly notify the Interested Parties, file a correction to the Annual Update with the FERC as an amended informational filing describing the change(s) and the cost impact, and provide a copy of the amended informational filing to PJM for prompt posting by PJM.~~

~~b. Necessary Changes When Made. Except as provided for below in Section 4.c, any corrections or revisions to the inputs and resulting rates that are required as a result of a change reported in Section 4.a shall be reflected in the next Annual Update, including any resulting refunds or surcharges for corrected past charges which shall be made with interest as per section 35.19a of the Commission's regulations.~~

~~c. Changes Made During the Review Period. Unless otherwise agreed by AEP and the Interested Parties, a correction made under Section 4.a prior to the time determined for the filing of a Formal Challenge shall reset the performance dates under Sections 2 and 3 of these Protocols for Interested Party Annual Review, and the revised dates shall run from the posting date(s) for each of the corrections. The scope of the Annual Review shall then be limited to the aspects of the Formula Rate affected by the corrections.~~

~~5. *American Elec. Power Svcs. Corp.*, 124 F.E.R.C. ¶ 61,306, P 36 (2008).~~

~~APPENDIX A~~
~~To Attachment H-14A~~

~~Cost of Service and Formula Rate Settlement Principles~~

~~American Electric Power Service Corporation~~
~~Docket No. ER08-1329~~

~~Transmission Formula Rate Settlement~~
~~For~~
~~Appalachian Power Company, Indiana Michigan Power Company, Kentucky Power Company, Kingsport Power Company, Ohio Power Company, and Wheeling Power Company~~
~~(collectively "AEP" or "the AEP East Companies")~~

~~The following Cost of Service and Formula Rate Settlement Principles are a part of the Settlement Agreement being filed on April 6, 2010 in Docket No. ER08-1329 ("the Settlement"):~~

~~I. Transmission Formula Rate Design.~~

~~A. Retail versus Wholesale Ratemaking Practices.~~

~~1. Differing practices among retail and wholesale regulatory jurisdictions - Costs that are not recoverable pursuant to FERC accounting and/or ratemaking practices may not be recovered by the AEP East companies through its FERC transmission formula rate.~~

~~2. Adjustments to the AEP cost of service formula rate templates - AEP shall take steps to have PJM include in the rate template used to calculate charges to transmission customers all of the adjustments, modifications, and corrections identified in the new formula rate templates included with this Statement of Settlement Principles.~~

~~3. Costs of transmission studies~~

~~a. All costs of transmission studies (*e.g.*, studies of requested new or modified delivery or interconnection points, System Impact Studies and Facilities Studies) associated with service to affiliated (*e.g.*, AEP East companies) and non-affiliated customers shall be allocated and charged to customers on a comparable and consistent basis.~~

~~b. Currently, the costs of transmission studies are directly assigned or charged to the requesting entity (including the AEP East companies) seeking the service. The costs of such studies shall be accounted for in one of the following ways:~~

~~i. The study costs are not included in the formula rate, expressly or otherwise; or~~

~~ii. If the costs are included in the formula rate but also are directly assigned to the entity requesting the study, then the formula rate also will include a revenue credit equal to the amount of study costs that are directly assignable to the requesting entity. Such~~

~~revenue credit shall be reflected in the formula rate regardless of the specific accounting applied to the costs and revenues.~~

~~ii. Study costs that are not directly assigned to the requesting entity may be treated as a system-wide cost in applying the formula rate, but only if that treatment is applied to all such study costs incurred for any requesting entity.~~

~~c. Transmission service base rate charges under the formula shall be calculated in a manner that allocates the costs of transmission studies to, and recovers those costs from, customers (including the AEP East companies themselves) on a comparable basis, without regard to whether the costs of those studies are directly assigned or rolled-in, and without regard to whether any particular studies are performed for affiliated or non-affiliated customers.~~

~~d. AEP will correct its books of account to remove from transmission investment the estimated costs of distribution-related studies that were inadvertently recorded as transmission overheads. The effect of this correction will be to reduce the transmission Rate Base used in formula rate calculations. This correction will be reflected in the 2009 end-of-year Transmission Plant In Service (TPIS) balance. In the 2010 Annual Update trueing up 2009 costs, the beginning-of-year 2009 TPIS balances shall be reduced by the same amount.~~

~~B. Rate Base~~

~~1. The transmission Rate Base used in the annual update shall be based upon the end-of-year net transmission plant balance from the prior calendar year FERC Form 1 ("FF1"). The true-up of the formula rate, however, shall utilize a Transmission Rate Base that incorporates the arithmetic average of the most recent actual values for beginning-of-year and end-of-year net transmission plant (that is, the average of beginning and end of calendar year balances for plant in service and accumulated depreciation).~~

~~a. The revenue requirements billed each July and running through June of the next year (except the first Rate Year which starts in March of 2009) will be based on a test-year-end rate base style annual transmission revenue requirement ("ATRR") calculation. This means there will be two sets of revenue requirements billed during 2009. The first set applies to the period from March through June, and is based on 2007 calendar year expenses and calendar year end rate base derived from the FF1 plus the projected 2008 calendar year plant-in-service additions. The second set was posted in May 2009, and applies from July 1, 2009 through June 30, 2010. Those revenue requirements will be based on the expenses and year-end TPIS balances obtained from the 2008 FF1 plus projected 2009 calendar year TPIS additions.~~

~~b. In 2010, the estimated ATRR that was effective during 2009 will be reconciled ("trued-up") with an ATRR that is calculated based on actual 2009 calendar year expenses and the arithmetic average of the beginning-of-year and end-of-year balances for TPIS and accumulated depreciation. The actual 2009 ATRR to be used for such reconciliation will be posted or otherwise provided to customers in May 2010 at the same time that the estimated ATRR to be used for billing purposes during the second half of 2010 is posted or otherwise provided to customers.~~

~~c. For the true-up of prior year charges, AEP East Companies will calculate the difference between the estimated ATRR for the prior calendar year that was used for billing purposes and the actual ATRR for that prior calendar year, calculated as described~~

~~in paragraph B.1.b. above. The difference between the two values (plus interest) shall be reflected as an addition to or offset against billed charges for transmission service beginning on July 1st of the current year. The interest rate will be calculated as per section 35.19a of the Commission's regulations.~~

~~d. The sequence outlined in paragraphs B.1.a, B.1.b and B.1.c above will be repeated each year.~~

~~2. Cash working capital for each AEP East operating company will be calculated as 1/8 of transmission-related O&M expense not including any portion of A&G expense allocated to transmission. (For example, using the historic formula from the template, the cash working capital reference on line 232 in the original filing which referenced (1/8 * ln 275) is now line 236 in the updated template and is changed to be (1/8 * ln 256.)~~

~~3. AEP shall change the line item description "Regulatory Assets Approved for Recovery in Ratebase" in Worksheet A for each operating company to "Regulatory Assets and Regulatory Liabilities Approved for Recovery in Ratebase." In addition, a note will be added stating that Regulatory Assets and Liabilities may be included in the formula rate calculations only if approved by the Commission in a proceeding pursuant to Section 205 or Section 206 of the Federal Power Act ("FPA").~~

~~4. If AEP includes plant held for future use in the formula rate ATRR calculation, then it also shall reflect any gains or losses on sales of such property in the ATRR calculation. Accordingly, AEP will modify the formula rate to include any amounts recorded in FERC Accounts 411.6 and 411.7 in the ATRR, and will prepare and include in its annual update filing a new Worksheet N, which shows the impact (net of income taxes) on the ATRR resulting from gains and losses on sales of plant held for future use.~~

~~5. AEP will provide as a part of its informational filing each May/June detail regarding ADIT balances for the historical year that is no less detailed, and selectively more detailed as described in this section, than what is included in Period I Statement AF (Accts. 281, 282, and 283) and Statement AG (Acct. 190) for each AEP operating company. In consideration of that commitment, the intervenors that are Settling Parties will not challenge the ADIT balances reflected in the Company's July 31, 2008 filing. In addition, AEP's information on ADIT will distinguish between utility and non-utility ADIT in order to ensure compliance with Section I.D.2.c.i. below.~~

~~6. AEP will be permitted to include in Rate Base in the formula rate the transmission portion of AEP's FAS 87 cash investment in Pre-Paid Pension cost recorded in FERC Account 165. If AEP elects to include such costs in Rate Base, it will use a labor expense allocation factor to allocate the total company amount to the TCOS.~~

~~7. In consideration of the agreements reached herein, AEP will remove the lines in the Formula Rate templates relating to CWIP. AEP retains the right to make a future filing(s) under section 205 of the Federal Power ACT for current recovery for CWIP.~~

~~C. Expenses~~

~~1. The formula rate shall allocate property tax expense based on the methodology of Worksheet Sheet H using the as-filed net plant cost allocation methodology. The Ohio Company merger ("reorganization") mitigation adjustment will be in effect for the Annual Updates prepared in 2012, 2013, 2014, 2015 and 2016.~~

~~2. The formula rate shall reflect the applicable state and federal statutory tax rates in effect during the period the calculated estimated unit charges are applicable. If statutory~~

~~tax rates change during such period, the effective tax rates used in the formula shall be weighted by the number of days the pre-change rate and the post-change rate each is in effect (*e.g.*, if a 40% rate is in effect nine months and a 32% rate is in effect 3 months, the weighted rate for the 12-month period would be 38%, which reflects 40% x 0.75 + 32% x 0.25 = 38%).~~

~~3. The formula shall include only expenses that are directly related to or properly allocable to transmission service.~~

~~4. Expenses recorded in FERC Accounts 928 (Regulatory Commission Expense), 930.1 (Safety Related Advertising) and 930.2 (Miscellaneous General Expenses) that are not directly related to or properly allocable to transmission service will be removed from the TCOS. If AEP includes any expenses booked to these accounts in future ATRR updates, AEP must provide supporting information demonstrating that the underlying activities are directly related to providing transmission service.~~

~~5. AEP's Depreciation rates contained in the FF1 are composite rates based on state commission-approved and FERC-approved depreciation rates. Composite rates are determined by plant account for each operating company that has more than one jurisdiction that approves depreciation rates, based on jurisdictional plant allocation factors. Attachments B-1 and B-2 to the Settlement Agreement contain a summary of AEP's state commission-approved depreciation rates for transmission plant. AEP will make a Section 205 filing at FERC to seek to change its composite depreciation rate methodology or to reflect in the formula rate calculations any change in state commission-approved or FERC- approved depreciation rates.~~

~~6. PBOP Expense~~

~~i. The formula rate shall include PBOP expense as illustrated in Worksheet O, which is included in Attachment F to the Settlement Agreement, and which will be included in the formula rate. Worksheet O provides that the PBOP allowance will be initially stated in the formula rate as $48.1 million for the AEP East system, with that amount to be shared by the AEP companies in each formula rate update in proportion to their actual PBOP costs, including each company's share of PBOP costs billed to the AEP operating companies by AEP Service Company.~~

~~ii. As part of the annual update process, AEP will provide to transmission customers, and include in its informational filing, an independently prepared actuarial report ("Annual Actuarial Report") that includes a ten (10) year forecast of PBOP costs when that report becomes available. The Settling Parties anticipate that the Annual Actuarial Report normally will be received by the time the annual update is posted or otherwise provided to customers each year.~~

~~iii. During the annual update process conducted in 2013, and every four years thereafter, Worksheet O will be used to determine whether, and if so by what amount, the PBOP allowance should be adjusted going forward for the next four years. If the Annual Actuarial Report produced for that year 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. In order to determine whether the AEP~~

~~Companies' cumulative allowance of PBOP costs under the formula rate will result in a cumulative over or under-recovery of actual PBOP expenses exceeding 20% over the subsequent four year period, Worksheet O will be used to determine the following PBOB cost/allowance values:~~

~~(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 rate True-Up transmission cost-of-service ("TCOS") analyses;~~

~~(b) the cumulative net present value ("CNPV") of projected PBOP costs during the next four years, as estimated by the then current Actuarial Report, assuming a discount rate equal to the True-Up TCOS WACC for the prior calendar year ("Prior Year WACC"); and~~

~~(c) the CNPV 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, (a) + (b) - (c), 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.~~

~~iv. If it is determined through the foregoing procedure that the AEP Companies' cumulative PBOP expense allowance 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 § 205 to change the PBOP expense stated in the formula rate. No other changes to the formula rate may be included in that filing. Neither AEP nor any Settling Party may raise in connection with such filing any issue affecting the formula rate other than the level of allowable PBOP expense.~~

~~v. The foregoing procedure for required updating of the formula rate's stated PBOP expense amount shall not affect either: (i) AEP's right to make filings under FPA § 205 to address aspects of the formula rate other than PBOP expense, or (ii) customers' rights to make filings under FPA § 206 to address aspects of the formula rate other than the PBOP expense.~~

~~D. Capital Structure, Cost of Capital and Return on Equity~~

~~1. Return on Equity~~

~~a. The Settlement shall establish on a non-precedential basis a base return on common equity ("Base ROE") used in the OATT transmission formula rates applicable to the AEP East zone of 10.99%, plus a 50 basis point adder for continued RTO participation (for a total of 11.49% ROE).~~

~~b. The Settlement shall not establish a lower or upper end of the zone of reasonableness, but for a period of 36 months from the effective date of the Settlement, AEP will limit any request for an incentive ROE pursuant to Order No. 679 and Order~~

~~No. 679-A to not more than the total ROE plus 125 basis points, (*i.e.*, 12.74% total incentive ROE). Such incentive ROE must be within the then-applicable zone of reasonableness as determined in a Section 205 or 206 proceeding. Settling Parties reserve the right to protest any request by AEP for incentive rates including any request for an incentive ROE.~~

~~2. Capital Structure / Cost of Capital:~~

~~a. In the annual true-up calculations, AEP shall use the arithmetic average of the beginning-of-year and end-of-year balances of long-term debt and calendar year interest expenses. The balances of any fair value hedges on interest rate derivatives of long term debt shall not be included in the average.~~

~~b. In the estimated (projected) ATRR used for billing purposes, AEP shall use the most recent available FF1 actual end-of-year balances of outstanding long term debt (less the balance of any fair value interest rate hedges), preferred equity, and common equity. The estimated cost rate for long term debt for the Projected Rate Year shall reflect the prior calendar year actual cost of long term debt (including periodic expenses such as remarketing and letter of credit fees, and related amortizations, as applicable, of issuance/reacquisition cost and discount or premium amortizations, and the amortization of eligible net hedging costs) for debt outstanding during the full year and the annualized cost of any issuances that occur after January 1 of the prior calendar year for a full twelve months coupon interest expense.~~

~~c. Except as provided for below regarding interest rate hedge gains and losses, the cost rates for long-term debt shall include interest expense, and related periodic expenses (such as remarketing and letter of credit fees) as recorded in FERC Account 427 or 430, amortization of issuance costs (including insurance), and discounts as recorded in FERC Account 428, issuance premiums as recorded in FERC Account 429, and losses or gains on reacquired debt as recorded in FERC Accounts 428.1 or 429.1, respectively. The cost rates for preferred stock shall include the dividends.~~

~~The cost rates for long-term debt shall include amortization of gains and losses resulting from interest rate hedging recorded in FERC Account 427 provided that only the gains and losses on the effective portion of pre-issuance cash flow hedges on interest rate derivatives of long term debt are eligible to be included in interest expense in the annual true-up ATRR calculation. No gains/losses and related ADIT on fair value interest rate hedges, the ineffective portion of pre-issuance interest rate cash flow hedges, post-issuance cash flow hedges, and cash flow hedges of variable rate debt issuances may be included in the true-up ATRR. The realized hedge gain or loss on the effective portion of pre-issuance cash flow hedges shall be amortized over the life of the associated debt security or refunding debt security, as applicable. The amount of net hedging gain or loss included in the annual true -up calculations shall not cause the after-tax weighted average cost of capital to increase or decrease by more than five (5) basis points. To determine the includable amount of hedging net losses or net gains to establish the long term debt cost rate, AEP will multiply the total company average true-up dollar capitalization (long-term debt net of any fair value hedge balances, preferred stock and common equity) by 0.0005, and compare the result to the full eligible net hedging loss or gain amortization amounts. The unamortized balances of eligible hedge gains/losses and their related ADIT amounts (FERC Accounts 190,282, and 283) shall not flow through the formula rate. AEP's corporate accounting records shall clearly segregate eligible hedge~~

~~gains/losses and related ADIT from ineligible hedge gains/losses and related ADIT. AEP shall provide on request during discovery periods provided for in this settlement, supporting hedge information including but not limited to copies of all eligible and ineligible hedge transaction internal authorization documents and company policies and procedures.~~

~~d. In applying the formula rate to determine charges for service rendered between March 1, 2009 and December 31, 2011, the amounts of common equity used in determining the weighted average cost of capital for the AEP East operating companies shall not exceed the following percentages of the total true-up capitalization ("Equity Caps"), regardless of the actual amounts of common equity capital outstanding:~~

~~Ohio Power Company~~	~~55 %~~
~~Appalachian Power Company~~	~~50 %~~
~~Indiana Michigan Power Company~~	~~50 %~~
~~Kentucky Power Company~~	~~50 %~~

~~If the percentage of common equity in an operating company's capitalization exceeds the applicable Equity Cap, the amount of common equity exceeding the Equity Cap shall be assigned the same cost rate as long-term debt in the formula rate cost of capital calculations.~~

~~*The Equity Cap for Ohio Power Company shall be 51% for the Annual Updates prepared in 2012, 2013, 2014, 2015 and 2016.~~

~~E. Revenue Credits – The following principles shall be stated in the formula rate:~~

~~1. If the AEP East companies have any directly assigned transmission facilities, the revenue credits in the AEP East formula rate shall include all revenues associated with those directly assigned transmission facilities, irrespective of whether the loads of the customer are included in the formula rate divisor; provided, however, such addition to revenue credits shall not be reflected if the costs of such directly assigned transmission facilities are not included in the transmission plant balances on which the formula rate ATRR is based.~~

~~2. All transmission services revenues not credited to customers in monthly PJM billings shall be included in the formula rate calculation as reductions to the ATRR. Such amounts shall include transmission revenues received from PJM or other PJM Transmission Owners where the associated loads are not in the AEP Zone divisor, unless the revenues are attributable to AEP's base transmission rate charges for Network Integration Transmission Service ("Network Service") or long-term firm Point-to-Point Transmission Service.~~

~~F. Allocators.~~

~~1. The allocations of Administrative & General (A&G) expenses identified by three-digit FERC account in the Formula Rate Template and Worksheet F, Supporting Allocation of Specific O&M or A&G Expenses, may not be changed except through a~~

~~filing under FPA § 205 or 206. If AEP wishes to reflect new O&M or A&G expenses or accounts in future updates, it must include in such § 205 filing: (i) a specification of the basis on which it proposes to allocate a portion of such costs as is properly assignable to wholesale transmission service, and (ii) documentation sufficient to demonstrate the reasonableness of its proposed allocation factor consistent with applicable Commission precedent.~~

~~2. AEP shall change the treatment of FERC Accounts 565 in the formula to clarify that no Account 565 costs other than inter-company charges that net out (such as lease arrangements and transmission equalization payments/receipts between operating companies) will be included in the TCOS, unless first approved by FERC following a separate FPA § 205 filing by AEP.~~

~~II. Application of Interest Rate Calculation in True-Up~~

~~AEP shall include an interest rate worksheet as Attachment C to the Settlement Agreement specifying its procedure for applying interest to true-up over or under recoveries.~~

Attachment C

Attachment H-14B in Clean Form

ATTACHMENT H-14B
BLANK FORMULA TEMPLATE - CLEAN

AEP East Companies — For Twelve Months Ended

Transmission Cost of Service Formula Rate
Utilizing Actual/Projected FERC Form 1 Data

COMPANY NAME HERE

Line No.			Total	Allocator		Transmission Amount
1	REVENUE REQUIREMENT (w/o incentives)	(ln 143)				$0
2	REVENUE CREDITS	(Worksheet E ln 8) (Note A)	-	DA	1.00000	$ -
3	Facility Credits under PJM OATT Section 30.9	(Worksheet E ln 9) (Note X)				$ -
4	REVENUE REQUIREMENT For All Company Facilities	(ln 1 less ln 2 plus ln 3)				$ -

MEMO: The Carrying Charge Calculations on lines 7 to 12 below are used in calculating project revenue requirements billed through PJM Schedule 12, Transmission Enhancement Charges. The total non-incentive revenue requirements for these projects shown on line 5 is included in the total on line 4.

5	Revenue Requirement for PJM Schedule 12 Facilities (w/o incentives) (Worksheet J/K)		-	DA	1.00000	$ -
6	NET PLANT CARRYING CHARGE w/o intra-AEP charges or credits or ROE incentives (Note B)					
7	Annual Rate	((ln 1 - ln 107)/ ((ln 49 + ln 50 + ln 51 + ln 52 + ln 54) x 100)				0.00%
8	Monthly Rate	(ln 7 / 12)				0.00%
9	NET PLANT CARRYING CHARGE ON LINE 7 , w/o depreciation or ROE incentives (Note B)					
10	Annual Rate	((ln 1 - ln 107 - ln 112) / ((ln 49 + ln 50 + ln 51 + ln 52 + ln 54) x 100)				0.00%
11	NET PLANT CARRYING CHARGE ON LINE 10, w/o Return, income taxes or ROE incentives (Note B)					
12	Annual Rate	((ln 1 - ln 107 - ln 112 - ln 138 - ln 139) / ((ln 49 + ln 50 + ln 51 + ln 52 + ln 54) x 100)				0.00%
13	ADDITIONAL REVENUE REQUIREMENT for projects w/ incentive ROE's (Note B) (Worksheet J/K)					-
14	**REVENUE REQUIREMENT FOR SCHEDULE 1A CHARGES**					
15	Total Load Dispatch & Scheduling (Account 561)	Line 86 Below				-
16	Less: Load Dispatch - Scheduling, System Control and Dispatch Services (321.88.b)					
17	Less: Load Dispatch - Reliability, Planning & Standards Development Services (321.92.b)					
18	Total 561 Internally Developed Costs	(Line 15 - Line 16 - Line 17)				-

AEP East Companies

Transmission Cost of Service Formula Rate

Utilizing Actual/Projected FERC Form 1 Data

COMPANY NAME HERE

Line No.	(1) RATE BASE CALCULATION	(2) Data Sources (See "General Notes")	TO Total (3) NOTE C	(4) Allocator		(5) Total Transmission
	GROSS PLANT IN SERVICE					
19	Production	(Worksheet A ln 1.E)	-	NA	0.00000	-
20	Less: Production ARO (Enter Negative)	(Worksheet A ln 2.E)	-	NA	0.00000	-
21	Transmission	(Worksheet A ln 3.E & Ln 147)	-	DA		-
22	Less: Transmission ARO (Enter Negative)	(Worksheet A ln 4.E)	-	TP	0.00000	-
23	Line Deliberately Left Blank		-	NA	0.00000	-
24	Line Deliberately Left Blank		-	NA	0.00000	-
25	Distribution	(Worksheet A ln 5.E)	-	NA	0.00000	-
26	Less: Distribution ARO (Enter Negative)	(Worksheet A ln 6.E)	-	NA	0.00000	-
27	General Plant	(Worksheet A ln 7.E)	-	W/S	0.00000	-
28	Less: General Plant ARO (Enter Negative)	(Worksheet A ln 8.E)	-	W/S	0.00000	-
29	Intangible Plant	(Worksheet A ln 9.E)	-	W/S	0.00000	-
30	TOTAL GROSS PLANT	(sum lns 19 to 29)	-	**GP(h)=**	**0.000000**	-
				GTD=	**-**	
31	ACCUMULATED DEPRECIATION AND AMORTIZATION					
32	Production	(Worksheet A ln 12.E)	-	NA	0.00000	-
33	Less: Production ARO (Enter Negative)	(Worksheet A ln 13.E)	-	NA	0.00000	-
34	Transmission	(Worksheet A ln 14.E & 28.E)	-	**TP1=**	0.00000	-
35	Less: Transmission ARO (Enter Negative)	(Worksheet A ln 15.E)	-	**TP1=**	0.00000	-
36	Line Deliberately Left Blank		-	DA	1.00000	-
37	Line Deliberately Left Blank		-	DA	1.00000	-
38	Line Deliberately Left Blank		-	TP1	0.00000	-
39	Line Deliberately Left Blank		-	W/S	0.00000	-
40	Line Deliberately Left Blank		-	DA	1.00000	-
41	Distribution	(Worksheet A ln 16.E)	-	NA	0.00000	-
42	Less: Distribution ARO (Enter Negative)	(Worksheet A ln 17.E)	-	NA	0.00000	-
43	General Plant	(Worksheet A ln 18.E)	-	W/S	0.00000	-
44	Less: General Plant ARO (Enter Negative)	(Worksheet A ln 19.E)	-	W/S	0.00000	-
45	Intangible Plant	(Worksheet A ln 20.E)	-	W/S	0.00000	-
46	TOTAL ACCUMULATED DEPRECIATION	(sum lns 32 to 45)	-			-
47	NET PLANT IN SERVICE					
48	Production	(ln 19 + ln 20 - ln 32 - ln 33)	-			-
49	Transmission	(ln 21 + ln 22 - ln 34 - ln 35)	-			-
50	Line Deliberately Left Blank		-			-
51	Line Deliberately Left Blank		-			-
52	Line Deliberately Left Blank		-			-
53	Line Deliberately Left Blank		-			-
54	Line Deliberately Left Blank		-			-
55	Distribution	(ln 25 + ln 26 - ln 41 - ln 42)	-			-
56	General Plant	(ln 27 + ln 28 - ln 43 - ln 44)	-			-
57	Intangible Plant	(ln 29 - ln 45)	-			-
58	TOTAL NET PLANT IN SERVICE	(sum lns 48 to 57)	-	**NP(h)=**	**0.000000**	-
59	DEFERRED TAX ADJUSTMENTS TO RATE BASE (Note D)					
60	Account No. 281.1 (enter negative)	(Worksheet B, ln 2 & ln 5.E)	-	NA		-
61	Account No. 282.1 (enter negative)	(Worksheet B, ln 7 & ln 10.E)	-	DA		-
62	Account No. 283.1 (enter negative)	(Worksheet B, ln 12 & ln 15.E)	-	DA		-
63	Account No. 190.1	(Worksheet B, ln 17 & ln 20.E)	-	DA		-
64	Account No. 255 (enter negative)	(Worksheet B, ln 24 & ln 25.E)	-	DA		-
65	TOTAL ADJUSTMENTS	(sum lns 60 to 64)	-			-
66	PLANT HELD FOR FUTURE USE	(Worksheet A ln 29.E & ln 30.E)	-	DA		-
67	REGULATORY ASSETS	(Worksheet A ln 36. (E))	-	DA		-
68	WORKING CAPITAL	(Note E)				
69	Cash Working Capital	(1/8 * ln 89)	-			-
70	Transmission Materials & Supplies	(Worksheet C, ln 2.(F))	-	TP	0.00000	-
71	A&G Materials & Supplies	(Worksheet C, ln 3.(F))	-	W/S	0.00000	-
72	Stores Expense	(Worksheet C, ln 4.(F))	-	GP(h)	0.00000	-
73	Prepayments (Account 165) - Labor Allocated	(Worksheet C, ln 8.G)	-	W/S	0.00000	-
74	Prepayments (Account 165) - Gross Plant	(Worksheet C, ln 8.F)	-	GP(h)	0.00000	-
75	Prepayments (Account 165) - Transmission Only	(Worksheet C, ln 8.E)	-	DA	1.00000	-
76	Prepayments (Account 165) - Unallocable	(Worksheet C, ln 8.D)	-	NA	0.00000	-
77	TOTAL WORKING CAPITAL	(sum lns 69 to 76)	-			-
78	IPP CONTRIBUTIONS FOR CONSTRUCTION	(Note F) (Worksheet D, ln 8.B)	-	DA	1.00000	-
79	RATE BASE (sum lns 58, 65, 66, 67, 77, 78)		-			-

AEP East Companies

Transmission Cost of Service Formula Rate

Utilizing Actual/Projected FERC Form 1 Data

COMPANY NAME HERE

Line No.	(1) EXPENSE, TAXES, RETURN & REVENUE REQUIREMENTS CALCULATION	(2) Data Sources (See "General Notes")	(3) TO Total	(4) Allocator		(5) Total Transmission
	OPERATION & MAINTENANCE EXPENSE					
80	Production	321.80.b				
81	Distribution	322.156.b				
82	Customer Related Expense	322 & 323.164,171,178.b				
83	Regional Marketing Expenses	322.131.b				
84	Transmission	321.112.b				
85	TOTAL O&M EXPENSES	(sum lns 80 to 84)	-			
86	Less: Total Account 561	(Note G) (Worksheet F, ln 14.C)	-			
87	Less: Account 565	(Note H) 321.96.b				
88	Less: Regulatory Deferrals & Amortizations	(Note I) (Worksheet F, ln 4.C)	-			
89	Total O&M Allocable to Transmission	(lns 84 - 86 - 87 - 88)	-	TP	0.00000	-
90	Administrative and General	323.197.b (Note J)				
91	Less: Acct. 924, Property Insurance	323.185.b				
92	Acct. 9260039 PBOP Expense	PBOP Worksheet O Line 9 & 10, (Note K)				
93	Acct. 9260057 PBOP Medicare Subsidy	PBOP Worksheet O Line 11, (Note K)				
94	PBOP Expense Billed From AEPSC	PBOP Worksheet O Line 13, (Note K)				
95	Acct. 928, Reg. Com. Exp.	323.189.b				
96	Acct. 930.1, Gen. Advert. Exp.	323.191.b				
97	Acct. 930.2, Misc. Gen. Exp.	323.192.b				
98	Balance of A & G	(ln 90 - sum ln 91 to ln 97)	-	W/S	0.00000	-
99	Plus: Acct. 924, Property Insurance	(ln 91)	-	GP(h)	0.00000	-
100	Acct. 928 - Transmission Specific	Worksheet F ln 20.(E) (Note L)	-	TP	0.00000	-
101	Acct 930.1 - Only safety related ads - Direct	Worksheet F ln 37.(E) (Note L)	-	TP	0.00000	-
102	Acct 930.2 - Misc Gen. Exp. - Trans	Worksheet F ln 43.(E) (Note L)	-	DA	1.00000	-
103	Settlement Approved PBOP Recovery	PBOP Worksheet O, Col. C, Line 1, (Note M)		W/S	0.00000	-
104	A & G Subtotal	(sum lns 98 to 103)	-			-
105	O & M EXPENSE SUBTOTAL	(ln 89 + ln 104)	-			-
106	Line Deliberately Left Blank					
107	Plus: Transmission Lease Payments To Affiliates in Acct 565 (Company Records) (Note H)			DA	1.00000	-
108	TOTAL O & M EXPENSE	(ln 105 + ln 107)	-			-
109	DEPRECIATION AND AMORTIZATION EXPENSE					
110	Production	336.2-6.f		NA	0.00000	-
111	Distribution	336.8.f		NA	0.00000	-
112	Transmission	336.7.f		TP1	0.00000	-
113	Line Deliberately Left Blank		-			-
114	General	336.10.f		W/S	0.00000	-
115	Intangible	336.1.f		W/S	0.00000	-
116	TOTAL DEPRECIATION AND AMORTIZATI0N	(Ln 110+111+112+113+114+115)	-			-
117	TAXES OTHER THAN INCOME	(Note N)				
118	Labor Related					
119	Payroll	Worksheet H ln 24.(D)	-	W/S	0.00000	-
120	Plant Related					
121	Property	Worksheet H ln 24.(C) & ln 59.(C)	-	DA		0
122	Gross Receipts/Sales & Use	Worksheet H ln 24.(F)	-	NA	0.00000	-
123	Other	Worksheet H ln 24.(E)	-	GP(h)	0.00000	-
124	TOTAL OTHER TAXES	(sum lns 119 to 123)	-			-
125	INCOME TAXES	(Note O)				
126	T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =		0.00%			
127	EIT=(T/(1-T)) * (1-(WCLTD/WACC)) =		0.00%			
128	where WCLTD=(ln 167) and WACC = (ln 170)					
129	and FIT, SIT & p are as given in Note O.					
130	GRCF=1 / (1 - T) = (from ln 126)		-			
131	Amortized Investment Tax Credit (enter negative)	(FF1 p.114, ln 19.c)	-			
132	Excess Deferred Income Tax	(Note U)	-	DA	1.00000	-
133	Tax Effect of Permanent Differences	(Note U)	-	DA	1.00000	-

134	Income Tax Calculation	(ln 127 * ln 139)	-			-
135	ITC adjustment	(ln 130 * ln 131)	-	NP(h)	0.00000	-
136	Excess Deferred Income Tax	(ln 130 * ln 132)	-			-
137	Tax Effect of Permanent Differences	(ln 130 * ln 133)	-			-
138	TOTAL INCOME TAXES	(sum lns 134 to 137)	-			-
139	RETURN ON RATE BASE (Rate Base*WACC)	(ln 79 * ln 170)	-			-
140	INTEREST ON IPP CONTRIBUTION FOR CONST. (Note F) (Worksheet D, ln 2.(B))		-	DA	1.00000	-
141	(Gains) / Losses on Sales of Plant Held for Future Use (Worksheet N, ln 4, Cols. ((F) & (H))			-		-
142	Tax Impact on Net Loss / (Gain) on Sales of Plant Held for Future Use (ln 141 * ln 127)			-		-
143	TOTAL REVENUE REQUIREMENT (sum lns 108, 116, 124, 138, 139, 140, 141, 142)		-			-

AEP East Companies

Transmission Cost of Service Formula Rate

Utilizing Actual/Projected FERC Form 1 Data

COMPANY NAME HERE

SUPPORTING CALCULATIONS

ln No.	TRANSMISSION PLANT INCLUDED IN PJM TARIFF			
144	Total transmission plant	(ln 21)		-
145	Less transmission plant excluded from PJM Tariff (Note P)			-
146	Less transmission plant included in OATT Ancillary Services (Worksheet A, ln 23, Col. (E)) (Note Q)			-
147	Transmission plant included in PJM Tariff	(ln 144 - ln 145 - ln 146)		-
148	Percent of transmission plant in PJM Tariff	(ln 147 / ln 144)	TP =	**0.00000**

149	WAGES & SALARY ALLOCATOR (W/S)	(Note R)	Direct Payroll	Payroll Billed from AEP Service Corp.	Total				
150	Production	354.20.b			-	NA	0.00000	-	
151	Transmission	354.21.b			-	TP	0.00000	-	
152	Regional Market Expenses	354.22.b			-	NA	0.00000	-	
153	Distribution	354.23.b			-	NA	0.00000	-	
154	Other (Excludes A&G)	354.24,25,26.b			-	NA	0.00000	-	
155	Total	(sum lns 150 to 154)	0	0	0			-	
156	Transmission related amount						W/S=		**0.00000**

157	WEIGHTED AVERAGE COST OF CAPITAL (WACC)		$
158	Long Term Interest	(Worksheet M, ln. 21, col. (E))	-
159	Preferred Dividends	(Worksheet M, ln. 55, col. (E))	-
160	Development of Common Stock:		
161	Proprietary Capital	(Worksheet M, ln. 1, col. (E))	
162	Less: Preferred Stock	(Worksheet M, ln. 2, col. (E))	
163	Less: Account 216.1	(Worksheet M, ln. 3, col. (E))	
164	Less: Account 219	(Worksheet M, ln. 4, col. (E))	
165	Common Stock	(ln 161 - ln 162 - ln 163 - ln 164)	-

166		$	%	Cost (Note S)	Weighted
167	Long Term Debt (Note T) Worksheet M, ln 11, ln 22, col. (E))	-	0.00%	-	0.0000
168	Preferred Stock (ln 162)	-	0.00%	-	0.0000
169	Common Stock (ln 165)	-	0.00%		0.0000
170	Total (Sum lns 167 to 169)	-		**WACC=**	**0.0000**

AEP East Companies
Transmission Cost of Service Formula Rate
Utilizing Actual/Projected FERC Form 1 Data
COMPANY NAME HERE

Letter	Notes
	General Notes: a) References to data from Worksheets are indicated as: Worksheet X, Line#.Column.X
A	Revenue credits include: 1) Forfeited Discounts. 2) Miscellaneous Service Revenues. 3) Rental revenues earned on assets included in the rate base. 4) Revenues for associated business projects provided by employees whose labor and overhead costs are in the transmission cost of service. 5) Other electric revenues. 6) Revenues for grandfathered PTP contracts included in the load divisor. 7) If AEP East companies have any directly assigned transmission facilities, the revenue credits in the AEP East formula rate shall include all revenues associated with those directly assigned transmission facilities, irrespective of whether the loads of the customer are included in the formula rate divisor; provided however, such addition to revenue credits shall not be reflected if the costs of such directly assigned transmission facilities are not included in the transmission plant balances on which the formula rate ATRR is based. See Worksheet E for details.
B	The annual and monthly net plant carrying charges on page 1 are used to compute the revenue requirement for RTEP sponsored upgrades or those projects receiving approved incentive-ROE's. Interest will be calculated based on Worksheet Q and any over under recovery will be filed and posted as part of the informational filing.
C	Transmission Plant Balances in this study are projected or actual average beginning of year end of year balances.
D	The total-company balances shown for Accounts 281, 282, 283, 190 only reflect ADIT that relates to utility operations. The balance of Account 255 is reduced by prior flow through and is completely excluded if the utility chose to utilize amortization of tax credits against FIT expense. An exception to this is pre-1971 ITC balances, which are required to be taken as an offset to rate base. Account 281 is not allocated. In compliance with FERC Rulemaking the calculation of ADIT in the annual projection will be performed in accordance with IRS regulation Section1.167(I)-I(h)(6)(ii). RM02-7-000, Asset Retirement Obligation deferrals have been removed from ratebase. Transmission ADIT allocations are shown on WS B. The company will not include the ADIT portion of deferred hedge gains and losses in rate base.Detailed balances for the projected or actual period, distinguished between utility and non-utility balances, will be filed and posted as part of the information filing.
E	Cash Working Capital assigned to transmission is one-eighth of O&M allocated to transmission, as shown on line 89. It excludes: 1) Load Scheduling & Dispatch Charges in account 561 that are collected in the OATT Ancilliary Services Revenue, as shown on line 86. 2) Costs of Transmission of Electricity by Others, as described in Note H. 3) The impact of state regulatory deferrals and amortizations, as shown on line 88 4) All A&G Expenses, as shown on line 104.
F	Consistent with Paragraph 657 of Order 2003-A, the amount on line 78 is equal to the balance of IPP System Upgrade Credits owed to transmission customers that made contributions toward the construction of System upgrades, and includes accrued interest and unreturned balance of contributions. The annual interest expense is included on line 140.
G	Removes from the cost of service the Load Scheduling and Dispatch expenses booked to accounts 561.1 through 561.8. Expenses recorded in these accounts, with the exception of 561.4 & 561.8 (lines 16 & 17 above) are recovered in Schedule 1A, OATT ancillary services rates. See Worksheet F, lines 5 through 14, for descriptions and the Form 1 Source of these accounts' balances.
H	Removes cost of transmission service provided by others to determine the basis of cash working capital on line 89. To the extent such service is incurred to provide the PJM service at issue, e.g. lease payments to affiliates, such cost is added back on line 107 to determine the total O&M collected in the formula. The amount on line 107 is also excluded in the calculation of the FCR percentage calculated on lines 6 through 12. The addbacks on line 107 of activity recorded in 565 represents inter-company sales or purchases of transmission capacity necessary to meet each AEP company's transmission load relative to their available transmission capacity. The company records referenced on line 107 is the COMPANY NAME HERE general ledger.
I	Removes the impact of state regulatory deferrals or their amortization from Transmission O&M expense.

J General Plant and Administrative & General expenses, other than in accounts 924, 928, and 930, will be functionalized based on the Wages & Salaries "W/S" allocator. The allocation basis for accounts 924, 928 and 930 are separately presented in the formula. A change in the allocation method for an account must be approved via a 205 filing with the FERC.

K These deductions on lines 92 through 94 are to remove from the cost of service the expenses recorded by the company for Postemployment Benefits Other than Pensions (PBOP). See Note M below for the recoverable PBOP expense.

L Expenses recorded in FERC Accounts 928 (Regulatory Commission Expense), 930.1 (Safety Related Advertising) and 930.2 (Miscellaneouse General Expenses) that are not directly related to or properly allocable to transmission service will be removed from the TCOS. If AEP includes any expenses booked to these accounts in future ATRR updates, AEP must provide supporting information demonstrating that the underlying activities are directly related to providing transmission service. Account 930.2 includes the expenses incurred by the transmission function for Associated Business Development revenues given as a credit to the TCOS on Worksheet E.

M See note K above. Per the settlement in Docket ER08-1329, recoverable PBOP expense is based on an annual total for the operating companies that is ratioed to them based on the total of actual annual PBOP costs, including charges from the AEP Service Corporation. The calculation of the recoverable amount for each company is shown on Worksheet O.

N Includes only FICA, unemployment, highway, property and other assessments charged in the current year. Gross receipts, sales & use and taxes related to income are excluded.

O The currently effective income tax rate, where FIT is the Federal income tax rate; SIT is the State income tax rate, and p = the percentage of federal income tax deductible for state income taxes. See Worksheet G for the development of the Company's composite SIT.
A utility that elected to utilize amortization of tax credits against taxable income, rather than book tax credits to Account No. 255 and reduce rate base, must reduce its income tax expense by the amount of the Amortized Investment Tax Credit (Form 1, 266.8.f).
(ln 131) multiplied by (1/1-T) . If the applicable tax rates are zero enter 0.

Inputs Required:	FIT =	0.00%	
	SIT=	0.00%	(State Income Tax Rate or Composite SIT. Worksheet G))
	p =	0.00%	(percent of federal income tax deductible for state purposes)

The formula rate shall reflect the applicable state and federal statutory tax rates in effect during the period the calculated estimated unit charges are applicable. If the statutory tax rates change during such period, the effective tax rates used in the formula shall be weighted by the number of days the pre-change rate and post-change rate each is in effect.

P Removes plant excluded from the OATT because it does not meet the PJM's definition of Transmission Facilities or is otherwise ineligible to be recovered under the OATT.

Q Removes transmission plant (e.g. step-up transformers) included in the development of OATT ancillary service rates and not already removed for reasons indicated in Note P.

R Includes functional wages & salaries billed by AEP Service Corporation for support of the operating company.

S Long Term Debt cost rate = long-term interest (ln 158) /average long term debt (ln 167). Preferred Stock cost rate = preferred dividends (ln 159) / preferred outstanding (ln 168). Common Stock cost rate (ROE) = 11.49%, the rate accepted by FERC in Docket No. ER08-1329. It includes an additional 50 basis points for PJM RTO membership. The amount of eligible hedging gains or losses included in total interest expense is limited to five basis points of the capital structure. Details and calculations of the weighted average cost of capital are shown on Worksheet M. Eligible Hedging Gains and Losses are computed on Worksheet M. The unamortized balance of eligible hedge gains/losses and related ADIT amounts shall not flow through the formula rate.

T The Long Term Debt balance for I&M includes the accumulated balance of principle and related interest for Spent Nuclear Fuel Disposal Costs collected prior to April 7, 1983. This total balance of _________ at 12/31/___ is not included in the balance in line 167 above. The cost rates for long-term debt shall include interest expense and related periodic expenses (such as remarketing and letter of credit fees) as recorded in FERC Account 427 or 430, amortization of issuance costs (including insurance) and discounts as recorded in FERC Account 428, issuance premiums as recorded in FERC Account 429 and losses or gains on reacquired debt as recorded in FERC Accounts 428.1 or 429.1, respectively. The cost rates for preferred stock (if applicable) shall include the dividends.

U Tax effect of permanent differences captures the differences in the income taxes due under the Federal and State calculations that are not the result of timing differences. Transmission balances for the projected or actual period, will be filed and posted as part of the informational filing.

V Cash investment in prepaid pension and benefits recorded in FERC Account 165 is permitted to be included in the formula. A labor expense allocation factor will be used to allocate total company costs. All other prepayments recorded in FERC Account 165 are directly assigned to the transmission function, allocated or excludable balances detailed on Worksheet C.

W The formula rate shall allocate property tax expense based on the as filed net plant cost allocation method detailed on Worksheet H.

X Under Section 30.9 of the PJM OATT, a network customer that owns existing transmission facilities that are integrated with the Transmission Provider's Transmission System may be eligible to receive consideration either through a billing credit or some other mechanism. Calculation of any credit under this subsection, pursuant to approval by FERC for inclusion in this formula rate for collection on behalf of the network customer, shall be addressed in either the Network Customer's Service Agreement or any other agreement between the parties.

AEP East Companies

Cost of Service Formula Rate Using Actual/Projected FF1 Balances

Worksheet A Supporting Plant Balances

COMPANY NAME HERE

	(A)		(B)	(C)	(D)	(E)
Line Number	**Rate Base Item & Supporting Balance**	**Source of Data**		**Balance @ December 31, Rate Year**	**Balance @ December 31, Rate Year-1**	**Average Balance for Rate Year**
NOTE: Functional ARO investment and accumulated depreciation balances shown below are included in the total functional balances shown here.						
Plant Investment Balances						
1	**Production Plant In Service**	FF1, page 205 Col.(g) & pg. 204 Col. (b), ln 46				-
2	**Production Asset Retirement Obligation (ARO)**	FF1, page 205&204, Col.(g)&(b), lns 15,24,34,44				-
3	**Transmission Plant In Service**	FF1, page 207 Col.(g) & pg. 206 Col. (b), ln 58				-
4	**Transmission Asset Retirement Obligation**	FF1, page 207 Col.(g) & pg. 206 Col. (b), ln 57				-
5	**Distribution Plant In Service**	FF1, page 207 Col.(g) & pg. 206 Col. (b), ln 75				-
6	**Distribution Asset Retirement Obligation**	FF1, page 207 Col.(g) & pg. 206 Col. (b), ln 74				-
7	**General Plant In Service**	FF1, page 207 Col.(g) & pg. 206 Col. (b), ln 99				-
8	**General Asset Retirement Obligation**	FF1, page 207 Col.(g) & pg. 206 Col. (b), ln 98				-
9	**Intangible Plant In Service**	FF1, page 205 Col.(g) & pg. 204 Col. (b), ln 5				-
10	**Total Property Investment Balance**	(Sum of Lines: 3, 1, 5, 7, 9)		-	-	-
11	**Total ARO Balance (included in total on line 10)**	(Sum of Lines: 4, 2, 6, 8)		-	-	-
Accumulated Depreciation & Amortization Balances						
12	**Production Accumulated Depreciation**	FF1, page 219, lns 20-24, Col. (b)				-
13	**Production ARO Accumulated Depreciation**	Company Records - Note 1				-
14	**Transmission Accumulated Depreciation**	FF1, page 219, ln 25, Col. (b)				-
15	**Transmission ARO Accumulated Depreciation**	Company Records - Note 1				-
16	**Distribution Accumulated Depreciation**	FF1, page 219, ln 26, Col. (b)				-
17	**Distribution ARO Accumulated Depreciation**	Company Records - Note 1				-
18	**General Accumulated Depreciation**	FF1, page 219, ln 28, Col. (b)				-
19	**General ARO Accumulated Depreciation**	Company Records - Note 1				-
20	**Intangible Accumulated Amortization**	FF1, page 200, ln 21, Col. (b)				-
21	**Total Accumulated Depreciation or Amortization**	(Sum of Lines: 14, 12, 16, 18, 20)		-	-	-
22	**Total ARO Balance (included in total on line 21)**	(Sum of Lines: 15, 13, 17, 19)		-	-	-
Generation Step-Up Units						
23	**GSU Investment Amount**	Company Records - Note 1				-
24	**GSU Accumulated Depreciation**	Company Records - Note 1				-
25	**GSU Net Balance**	(Line 23 - Line 24)		-	-	-
Transmission Accumulated Depreciation Net of GSU Accumulated Depreciation						
26	**Transmission Accumulated Depreciation**	(Line 14 above)		-	-	-
27	**Less: GSU Accumulated Depreciation**	(Line 24 above)		-	-	-
28	**Subtotal of Transmission Net of GSU**	(Line 26 - Line 27)		-	-	-
Plant Held For Future Use						
29	**Plant Held For Future Use**	FF1, page 214, ln 47, Col. (d)				-
30	**Transmission Plant Held For Future**	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.						
31						-
32						-
33						-
34						-
35						-
36	Total Regulatory Deferrals Included in Ratebase			-	-	-

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

NOTE: The ratebase should not include the unamoritzed balance of hedging gains or losses.

AEP East Companies
Cost of Service Formula Rate Using Actual/Projected FF1 Balances
Worksheet B Supporting ADIT and ITC Balances
COMPANY NAME HERE

Line Number	(A) Description	(B) Source	(C) Balance @ December 31, Rate Year	(D) Balance @ December 31, Rate Year-1	(E) Average Balance for Rate Year
1	**Account 281**				
2	Year End Utility Deferrals	FF1, p. 272 - 273, ln 8, Col. (k)			-
3	Less: ARO Related Deferrals	Company Records - Note 1			-
4	Less: Other Excluded Deferrals	Company Records - 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	Company Records - Note 1			-
9	Less: Other Excluded Deferrals	Company Records - 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	Company Records - Note 1			-
14	Less: Other Excluded Deferrals	Company Records - 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	Company Records - Note 1			-
19	Less: Other Excluded Deferrals	Company Records - 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 Ratebase	Ln 22 - ln 23	-	-	-
25	Transmission Related Deferrals	Company Records - Note 1			-

NOTE 1 On this worksheet, "Company Records" refers to AEP's tax accounting ledger. Projected ending balances reflect proration required by IRS Letter Rule Section 1.167(l)-l(h)(6)(ii).

NOTE 2 ADIT balances should exclude balances related to hedging activity.

AEP East Companies
Cost of Service Formula Rate Using Actual/Projected FF1 Balances
Worksheet C Supporting Working Capital Rate Base Adjustments
COMPANY NAME HERE

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
			Materials & Supplies						
Line Number			**Source**	**Balance @ December 31, Rate Year**		**Balance @ December 31, Rate Year-1**		**Average Balance for Rate Year**	
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)	FF1, p. 227, ln 16, Col. (c) & (b)			-			
			Prepayment Balance Summary						
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, Rate Year	0	0	0	0	0	0	
7		Totals as of December 31, Rate Year-1							
8		**Average Balance**	-	-	-	-	-	-	
			Prepayments Account 165 - Balance @ 12/31/Rate Year						
9	**Acc. No.**	**Description**	**Rate Year 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/ Rate Year-1						
20	**Acc. No.**	**Description**	**Rate Year-1 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						0		-	
25				0				-	
26				0				-	
27				0				-	
28				0				-	
29							0	-	
30				0				-	
31				0				-	
		Subtotal - Form 1, p 111.57.c							

AEP East Companies
Cost of Service Formula Rate Using Actual/Projected FF1 Balances
Worksheet D Supporting IPP Credits
COMPANY NAME HERE

Line Number	(A) Description	(B) Rate Year
1	Net Funds from IPP Customers 12/31/Rate Year-1 (Rate Year FORM 1, P269, line 24.b)	
2	Interest Accrual (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/Rate Year (Rate Year FORM 1, P269, line 24.f)	-
8	Average Balance for Year as Indicated in Column ((ln 1 + ln 7)/2)	-

Note 1 On this worksheet Company Records refers to COMPANY NAME HERE's general ledger.

AEP East Companies
Cost of Service Formula Rate Using Actual/Projected FF1 Balances
Worksheet E Supporting Revenue Credits
COMPANY NAME HERE

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 - Note 1)**		-	
5	**Account 456 - Other Electric Revenues - (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**	-	-	-

Note 1 The total company data on this worksheet comes from the indicated FF1 source, or COMPANY NAME HERE's general ledger. The functional amounts identified as transmission revenue also come from the general ledger.

9	**Facility Credits under PJM OATT Section 30.9**			

AEP East Companies
Cost of Service Formula Rate Using Actual/Projected FF1 Balances
Worksheet F Supporting Allocation of Specific O&M or A&G Expenses
COMPANY NAME HERE

	(A)	(B)	(C)	(D)	(E)	(F)
Line Number	**Item No.**	**Description**	**Rate Year 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	FF1 p 321.84.b	561 - Load Dispatching				
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**	0			
		Account 928				
15				-	-	
16				-	-	
17				-	-	
18				-	-	
19				-	-	
20		**Total**	-	-	-	
		Account 930.1				
21				-	-	
22				-	-	
23				-	-	
24				-	-	
25				-	-	
26				-	-	
27				-	-	
28				-	-	
29				-	-	
30				-	-	
31				-	-	
32				-	-	
33				-	-	
34				-	-	
35				-	-	
36				-	-	
37		**Total**	-	-	-	
		Account 930.2				
38			0			
39			0			
40			0			
41			0			
42			0			
43		**Total**	-	-	-	

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	(C) Property	(D) Labor	(E) Other	(F) Non-Allocable
		NOTE 1				
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.					

Line No.	**Functional Property Tax Allocation**	Production	Transmsission	Distribution	General	Total
25	Functionalized Net Plant (TCOS, Lns 48 thru 58)	-	-	-	-	-
	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%		
36	Functionalized Expense in STATE JURISDICTION #1	-	-	-		-
	STATE JURISDICTION #2					
37	Percentage of Plant in STATE JURISDICTION #2					
38	Net Plant in STATE JURISDICTION #2 (Ln 25 * Ln 37)	-	-	-	-	-
39	Less: Net Value of Exempted Generation Plant					
40	Taxable Property Basis (Ln 38 - Ln 39)	-	-	-	-	-
41	Relative Valuation Factor					
42	Weighted Net Plant (Ln 40 * Ln 41)	-	-	-	-	
43	General Plant Allocator (Ln 42 / (Total - General Plant))	0.00%	0.00%	0.00%	-100.00%	
44	Functionalized General Plant (Ln 43 * General Plant)	-	-	-	-	-
45	Weighted STATE JURISDICTION #2 Plant (Ln 42 + 44)	-	-	-	-	-
46	Functional Percentage (Ln 45/Total Ln 45)	0.00%	0.00%	0.00%		
47	Functionalized Expense in STATE JURISDICTION #2	-	-	-		-
	STATE JURISDICTION #3					
48	Net Plant in STATE JURISDICTION #3 (Ln 25 - Ln 27 - Ln 38)	-	-	-	-	-
49	Less: Net Value Exempted Generation Plant					
50	Taxable Property Basis	-	-	-	-	-
51	Relative Valuation Factor					
52	Weighted Net Plant (Ln 50 * Ln 51)	-	-	-	-	
53	General Plant Allocator (Ln 52 / (Total - General Plant)	0.00%	0.00%	0.00%	-100.00%	
54	Functionalized General Plant (Ln 54 * General Plant)	-	-	-	-	
55	Weighted STATE JURISDICTION #3 Plant (Ln 52 + 54)	-	-	-	-	-
56	Functional Percentage (Ln 55/Total Ln 55)	0.00%	0.00%	0.00%		
57	Functionalized Expense in STATE JURISDICTION #3	-	-	-		-
58	Total Other Jurisdictions: (Line 7 * Net Plant Allocator)		-			-
59	Total Func. Property Taxes (Sum Lns 36, 47 57, 58)	-	-	-		-

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	-	
3	**Real Estate and Personal Property Taxes**		
4	Real and Personal Property - Jurisdiction 1	-	
5	Real and Personal Property - Other Jurisdictions	-	
6	**Payroll Taxes**		
7	Federal Insurance Contribution (FICA)	-	
8	Federal Unemployment Tax	-	
9	State Unemployment Insurance	-	
10	Payroll Taxes	-	-
11	**Production Taxes**		
12	Production Tax 1	-	
13	**Miscellaneous Taxes**		
14	Miscellaneous Tax 1	-	
15	Miscellaneous Tax 2	-	
16	Miscellaneous Tax 3	-	
17	Miscellaneous Tax 4	-	
18	Miscellaneous Tax 5	-	
19	Miscellaneous Tax 6	-	
20	Miscellaneous Tax 7	-	
21	Miscellaneous Tax 8	-	
22	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.

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 169)	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 167 through169)

	%	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 79)	-	
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 127)		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, 107)	-	
Return (TCOS, ln 139)		-
Income Taxes (TCOS, ln 138)	-	
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 112)	-
Annual Rev. Req, w/ Basis Point ROE increase, less Depreciation	-

C. Determine FCR with hypothetical basis point ROE increase.

Net Transmission Plant (TCOS, ln 49)	-	
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

Transmission Plant @ Beginning of Rate Year (P.206, ln 58,(b)):	-	
Transmission Plant @ End of Rate Year (P.207, ln 58,(g)):	-	
Subtotal	-	
Average Transmission Plant Balance for Rate Year	-	
Annual Depreciation and Amortization Expense (TCOS, ln 112)	-	
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)

Project Description:

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

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 169)	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 167 through169)

	%	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 79)	-		
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 127)		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 107)	-	
Return (TCOS, ln 139)		-
Income Taxes (TCOS, ln 138)	-	
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 112)	-
Annual Rev. Req, w/ Basis Point ROE increase, less Depreciation	-

C. Determine FCR with hypothetical basis point ROE increase.

Net Transmission Plant (TCOS, ln 49)		
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%

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	-	-	-

III. Calculation of Composite Depreciation Rate

Transmission Plant @ Beginning of Rate Year (P.206, ln 58,(b)):	-
Transmission Plant @ End of Rate Year (P.207, ln 58,(g)):	-
Subtotal	-

Average Transmission Plant Balance for	-	
Annual Depreciation and Amortization Expense (TCOS, ln 112)	-	
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	-

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

AEP East Companies
Transmission Cost of Service Formula Rate Using Actual/Projected FF1 Balances
COMPANY NAME HERE
Worksheet M Supporting Calculation of Capital Structure and Weighted Average Cost of Capital Based on Average of Balances At 12/31/Rate Year-1 & 12/31/Rate Year

(A) Line	(B)	(C) Balances @ 12/31/Rate Year	(D) Balances @ 12/31/Rate Year-1	(E) Average	
	Development of Average Balance of Common Equity				
1	Proprietary Capital (112.16.c&d)			-	
2	Less Preferred Stock (Ln 55 Below)	0	-	-	
3	Less Account 216.1 (112.12.c&d)			0	
4	Less Account 219.1 (112.15.c&d)			0	
5	**Average Balance of Common Equity**	-	-	-	
	Development of Cost of Long Term Debt Based on Average Outstanding Balance				
6	Bonds (112.18.c&d)			0	
7	Less: Reacquired Bonds (112.19.c&d)			0	
8	LT Advances from Assoc. Companies (112.20.c&d)			-	
9	Senior Unsecured Notes (112.21.c&d)			0	
10	Less: Fair Value Hedges (See Note on Ln 12 below)			0	
11	**Total Average Debt**	-	-	-	
12	**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. (Column H of the FF1)**				
13	**Annual Interest Expense for Rate Year**				
14	Interest on Long Term Debt (256-257.33.i)				
15	Less: Total Hedge Gain/Expense Accumulated from p 256-257, col. (i) of FERC Form 1				included in Ln 14 and shown in Ln 34 below.
16	Plus: Allowed Hedge Recovery From Ln 39 below.			-	
17	Amort of Debt Discount & Expense (117.63.c)				
18	Amort of Loss on Reacquired Debt (117.64.c)				
19	Less: Amort of Premium on Debt (117.65.c)				
20	Less: Amort of Gain on Reacquired Debt (117.66.c)				
21	**Total Interest Expense (Ln 14 + Ln 17 + Ln 18 - Ln 19 - Ln 20)**			-	
22	**Average Cost of Debt for Rate Year (Ln 21/Ln 11)**			**0.00%**	

CALCULATION OF RECOVERABLE HEDGE GAINS/LOSSES

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

Line	HEDGE AMOUNTS BY ISSUANCE (FROM p. 256-257 (i) of the FERC Form 1)	Total Hedge (Gain)/Loss for Rate Year	Less Excludable Amounts (See NOTE on Line 23)	Net Includable Hedge Amount	Remaining Unamortized Balance	Amortization Period Beginning	Amortization Period Ending
24	Senior Unsecured Notes			-			
25	Senior Unsecured Notes			-			
26	Senior Unsecured Notes			-			
27	Senior Unsecured Notes			-			
28	Senior Unsecured Notes			-			
29	Senior Unsecured Notes			-			
30	Senior Unsecured Notes			-			
31	Senior Unsecured Notes			-			
32	Senior Unsecured Notes			-			
33	Senior Unsecured Notes			-			
34	Total Hedge Amortization	-	-				
35	Hedge Gain or Loss Prior to Application of Recovery Limit (Sum of Lines 24 to 33)			-			
36	Total Average Capital Structure Balance for Rate Year (TCOS, Ln 170)			-			
37	Financial Hedge Recovery Limit - Five Basis Points of Total Capital			0.0005			
38	Limit of Recoverable Amount			-			
39	**Recoverable Hedge Amortization (Lesser of Ln 35 or Ln 38)**			-			

Development of Cost of Preferred Stock

Line	**Preferred Stock**	(C)	(D)	**Average**	
40	0% Series - - Dividend Rate (p. 250-251. 7 & 10.a)				
41	0% Series - - Par Value (p. 250-251. 8.c)				
42	0% Series - - Shares O/S (p.250-251. 8 & 11.e)				
43	0% Series - - Monetary Value (Ln 41 * Ln 42)	-	-	-	
44	0% Series - - Dividend Amount (Ln 40 * Ln 43)	-	-	-	
45	0% Series - - Dividend Rate (p. 250-251.a)				
46	0% Series - - Par Value (p. 250-251.c)				
47	0% Series - - Shares O/S (p.250-251. e)				
48	0% Series - - Monetary Value (Ln 46 * Ln 47)	-	-	-	
49	0% Series - - Dividend Amount (Ln 45 * Ln 48)	-	-	-	
50	0% Series - - Dividend Rate (p. 250-251.a)				
51	0% Series - - Par Value (p. 250-251.c)				
52	0% Series - - Shares O/S (p.250-251.e)				
53	0% Series - - Monetary Value (Ln 51 * Ln 52)	-	-	-	
54	0% Series - - Dividend Amount (Ln 50 * Ln 53)	-	-	-	
55	**Balance of Preferred Stock (Lns 43, 48, 53)**	-	-	-	Year End Total Agrees to FF1 p.112, Ln 3, col (c) & (d)
56	**Dividends on Preferred Stock (Lns 44, 49, 54)**	-	-	-	
57	**Average Cost of Preferred Stock (Ln 56/55)**	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%	-		-	-	-
5	KNGP		0.00%	-		-	-	-
6	OPCo		0.00%	-		-	-	-
7	WPCo		0.00%	-		-	-	-
8	**Sum of Lines 1 to 8**	-		-		-	-	-

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

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

Note: PBOP Expense will be calculated in accordance with the settlement in Docket ER08-1329.

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 6/1/2015

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				6.67%	1.000000	6.67%								6.67%
Structures & Improvements	352.0	1.55%	0.469583	0.73%	1.52%	0.437847	0.67%	2.19%	0.036426	0.08%		2.19%	0.056144	0.12%	1.60%
Station Equipment	353.0	1.95%	0.4695834	0. 92%	1.68%	0.437847	0.74%	2.19%	0.036426	0.08%		2.19%	0.056144	0.12%	1.86%
Towers & Fixtures	354.0	1.14%	0.469583	0.54%	1.54%	0.437847	0.67%	2.19%	0.036426	0.08%		2.19%	0.056144	0.12%	1.41%
Poles & Fixtures	355.0	2.77%	0.4695834	1.30%	2.64%	0.437847	1.16%	2.19%	0.036426	0.08%		2.19%	0.056144	0.12%	2.66%
Overhead Conductor	356.0	1.01%	0.4695834	0.47%	1.19%	0.437847	0.52%	2.19%	0.036426	0.08%		2.19%	0.056144	0.12%	1.19%
Underground Conduit	357.0	1.23%	0.469583	0.58%	1.45%	0.437847	0.63%	2.19%	0.036426	0.08%		2.19%	0.056144	0.12%	1.41%
Underground Conductors	358.0	3.18%	0.469583	1.49%	7.23%	0.437847	3.17%	2.19%	0.036426	0.08%		2.19%	0.056144	0.12%	4.86%

(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 May 26, 2015in

Case No. 14-1151-E-D effective June 1, 2015.

(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 July 1, 2014

FOR MULTIPLE JURISDICTION COMPANIES

INDIANA MICHIGAN POWER COMPANY

		INDIANA			**MICHIGAN**			**FERC WHOLESALE**			**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	1.27%	.646552	.8211%	1.1700%	.139381	.1631%	1.1700%	.214067	.2505%	1.23%
Structures & Improvements	352.0	1.32%	.646552	.8534%	1.2700%	.139381	.1770%	1.2700%	.214067	.2719%	1.30%
Station Equipment	353.0	1.69%	.646552	1.0927%	1.6500%	.139381	.2300%	1.6500%	.214067	.3532%	1.68%
Towers & Fixtures	354.0	1.60%	.646552	1.0345%	1.4400%	.139381	.2007%	1.4400%	.214067	.3083%	1.54%
Poles & Fixtures	355.0	2.43%	.646552	1.5711%	2.3900%	.139381	.3331%	2.3900%	.214067	.5116%	2.42%
Overhead Conductors	356.0	1.53%	.646552	.9892%	1.4500%	.139381	.2021%	1.4500%	.214067	.3104%	1.50%
Underground Conduit	357.0	1.56%	.646552	1.0086%	1.3900%	.139381	.1937%	1.3900%	.214067	.2976%	1.50%
Underground Conductors	358.0	1.55%	.646552	1.0022%	1.4600%	.139381	.2035%	1.4600%	.214067	.3125%	1.52%
Trails & Roads	359.0	1.49%	.646552	.9634%	1.4700%	.139381	.2049%	1.4700%	.214067	.3147%	1.48%

(1) As approved in Indiana Case No.44075.

(2) As approved in Michigan Case No. U16801.

(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%**

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%

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		
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%

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.

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 6/1/2015

FOR SINGLE JURISDICTION COMPANIES

WHEELING POWER COMPANY

	PLANT ACCT.	RATES Note 1
TRANSMISSION PLANT		
Structures & Improvements	352.0	0.69%
Station Equipment	353.0	1.70%
Towers & Fixtures	354.0	0.04%
Poles & Fixtures	355.0	2.65%
Overhead Conductors	356.0	1.12%
Underground Conduit	357.0	2.00%
Underground Conductors	358.0	5.00%
Trails & Roads	359.0	-

Note 1: Rates Approved in WV Public Service Commission Case No. 14-1151-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.

Attachment D

Attachment H-14B in Redline Form

ATTACHMENT H-14B

BLANK FORMULA TEMPLATE - CLEAN

For Twelve Months Ended

AEP East Companies

Transmission Cost of Service Formula Rate

Utilizing ~~Historic Cost Data for Historic Year and~~ Actual/Projected ~~Net Plant at Year-End Projected Year~~FERC Form 1 Data

COMPANY NAME HERE

Line No.							Transmission Amount
1	REVENUE REQUIREMENT (w/o incentives)		(ln ~~138~~143)				$0
				Total		Allocator	
2	REVENUE CREDITS		~~(Note A)~~ (Worksheet E~~)~~ ln 8) (Note A)	-	D A	1.00000	$ -
3	Facility Credits under PJM OATT Section 30.9	~~REVENUE REQUIREMENT For All Company Facilities~~	(Worksheet E ln ~~1 less ln 29~~) (Note X) **~~MEMO: The Carrying Charge Calculations on lines 6 to 11 below are used in calculating project revenue requirements billed through PJM Schedule 12, Transmission Enhancement Charges. The total non-incentive revenue requirements for these projects shown on line 4 is included in the total on line 3.~~**				~~$~~ $ -
4	REVENUE REQUIREMENT For All Company Facilities		(ln 1 less ln 2 plus ln 3)				$ -

MEMO: The Carrying Charge Calculations on lines 7 to 12 below are used in calculating project revenue requirements billed through PJM Schedule 12, Transmission Enhancement Charges. The total non-incentive revenue requirements for these projects shown on line 5 is included in the total on line 4.

Line No.						Transmission Amount
~~4~~5	Revenue Requirement for PJM Schedule 12 Facilities (w/o incentives) (Worksheet J/K)		-	DA	1.00000	$ -
~~5~~6	NET PLANT CARRYING CHARGE w/o intra-AEP charges or credits or ROE incentives (Note B)					
~~6~~7	Annual Rate	((ln 1 - ln 107)/ ((ln 49 + ln 50 + ln 51 + ln 52 + ln 54) x 100) ~~Annual Rate~~		~~((ln 1 - ln 105 - ln 106)/((ln 48 + ln 49 + ln 50 + ln 51 + ln 53) x 100))~~		0.00%
~~7~~8	Monthly Rate	(ln ~~6~~7 / 12)				0.00%
~~8~~9	NET PLANT CARRYING CHARGE ON LINE ~~6~~7 , w/o depreciation or ROE incentives (Note B)					
~~9~~10	Annual Rate	((ln 1 - ln 107 - ln 112) / ((ln 49 + ln 50 + ln 51 + ln 52 + ln 54) x 100) ~~Annual Rate~~		~~((ln 1 - ln 105 - ln 106 - ln 111) /((ln 48 + ln 49 + ln 50 + ln 51 + ln 53) x 100))~~		0.00%
~~10~~ 11	NET PLANT CARRYING CHARGE ON LINE ~~9~~10, w/o Return, income taxes or ROE incentives (Note B)					
~~11~~ 12	Annual Rate	((ln 1 - ln ~~105~~107 - ln ~~106~~112 - ln ~~111~~138 - ln ~~133 - ln 134) /((ln 48 +~~ 139) / ((ln 49 + ln 50 + ln 51 + ln ~~53~~52 + ln 54) x 100)~~)~~				0.00%
~~12~~ 13	ADDITIONAL REVENUE REQUIREMENT for projects w/ incentive ROE's (Note B) (Worksheet J/K)					-
~~13~~ 14						-

REVENUE REQUIREMENT FOR SCHEDULE 1A CHARGES

Line No.			
~~14~~ 15	Total Load Dispatch & Scheduling (Account 561)	Line ~~85~~86 Below	-
~~15~~ 16	Less: Load Dispatch - Scheduling, System Control and Dispatch Services (321.88.b)		
~~16~~ 17	Less: Load Dispatch - Reliability, Planning & Standards Development Services (321.92.b)		

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~~17~~ 18	Total 561 Internally Developed Costs	(Line ~~14 - Line~~ 15 - Line 16 - Line 17)	-

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AEP East Companies

Transmission Cost of Service Formula Rate

Utilizing Actual/Projected FERC Form 1 Data

COMPANY NAME HERE

	(1)	(2)	(3)	(4)		(5)
	RATE BASE CALCULATION	**Data Sources (See "General Notes")**	**TO Total**	**Allocator**		**Total Transmission**
Line			NOTE C			
No.	GROSS PLANT IN SERVICE					
19	Production	(Worksheet A ln 1.E)	-	NA	0.00000	-
20	Less: Production ARO (Enter Negative)	(Worksheet A ln 2.E)	-	NA	0.00000	-
21	Transmission	(Worksheet A ln 3.E & Ln 147)	-	DA		-
22	Less: Transmission ARO (Enter Negative)	(Worksheet A ln 4.E)	-	TP	0.00000	-
23	Line Deliberately Left Blank		-	NA	0.00000	-
24	Line Deliberately Left Blank		-	NA	0.00000	-
25	Distribution	(Worksheet A ln 5.E)	-	NA	0.00000	-
26	Less: Distribution ARO (Enter Negative)	(Worksheet A ln 6.E)	-	NA	0.00000	-
27	General Plant	(Worksheet A ln 7.E)	-	W/S	0.00000	-
28	Less: General Plant ARO (Enter Negative)	(Worksheet A ln 8.E)	-	W/S	0.00000	-
29	Intangible Plant	(Worksheet A ln 9.E)	-	W/S	0.00000	-
30	TOTAL GROSS PLANT	(sum lns 19 to 29)	-	**GP(h)=**	**0.000000**	-
				GTD=	-	
31	ACCUMULATED DEPRECIATION AND AMORTIZATION					
32	Production	(Worksheet A ln 12.E)	-	NA	0.00000	-
33	Less: Production ARO (Enter Negative)	(Worksheet A ln 13.E)	-	NA	0.00000	-
34	Transmission	(Worksheet A ln 14.E & 28.E)	-	**TP1=**	0.00000	-
35	Less: Transmission ARO (Enter Negative)	(Worksheet A ln 15.E)	-	**TP1=**	0.00000	-
36	Line Deliberately Left Blank		-	DA	1.00000	-
37	Line Deliberately Left Blank		-	DA	1.00000	-
38	Line Deliberately Left Blank		-	TP1	0.00000	-
39	Line Deliberately Left Blank		-	W/S	0.00000	-
40	Line Deliberately Left Blank		-	DA	1.00000	-
41	Distribution	(Worksheet A ln 16.E)	-	NA	0.00000	-
42	Less: Distribution ARO (Enter Negative)	(Worksheet A ln 17.E)	-	NA	0.00000	-
43	General Plant	(Worksheet A ln 18.E)	-	W/S	0.00000	-
44	Less: General Plant ARO (Enter Negative)	(Worksheet A ln 19.E)	-	W/S	0.00000	-
45	Intangible Plant	(Worksheet A ln 20.E)	-	W/S	0.00000	-
46	TOTAL ACCUMULATED DEPRECIATION	(sum lns 32 to 45)	-			-
47	NET PLANT IN SERVICE					
48	Production	(ln 19 + ln 20 - ln 32 - ln 33)	-			-
49	Transmission	(ln 21 + ln 22 - ln 34 - ln 35)	-			-
50	Line Deliberately Left Blank		-			-
51	Line Deliberately Left Blank		-			-
52	Line Deliberately Left Blank		-			-
53	Line Deliberately Left Blank		-			-
54	Line Deliberately Left Blank		-			-
55	Distribution	(ln 25 + ln 26 - ln 41 - ln 42)	-			-
56	General Plant	(ln 27 + ln 28 - ln 43 - ln 44)	-			-
57	Intangible Plant	(ln 29 - ln 45)	-			-
58	TOTAL NET PLANT IN SERVICE	(sum lns 48 to 57)	-	**NP(h)=**	**0.000000**	-
59	DEFERRED TAX ADJUSTMENTS TO RATE BASE	(Note D)				
60	Account No. 281.1 (enter negative)	(Worksheet B, ln 2 & ln 5.E)	-	NA		-
61	Account No. 282.1 (enter negative)	(Worksheet B, ln 7 & ln 10.E)	-	DA		-
62	Account No. 283.1 (enter negative)	(Worksheet B, ln 12 & ln 15.E)	-	DA		-
63	Account No. 190.1	(Worksheet B, ln 17 & ln 20.E)	-	DA		-
64	Account No. 255 (enter negative)	(Worksheet B, ln 24 & ln 25.E)	-	DA		-
65	TOTAL ADJUSTMENTS	(sum lns 60 to 64)	-			-
66	PLANT HELD FOR FUTURE USE	(Worksheet A ln 29.E & ln 30.E)	-	DA		-
67	REGULATORY ASSETS	(Worksheet A ln 36. (E))	-	DA		-
68	WORKING CAPITAL	(Note E)				
69	Cash Working Capital	(1/8 * ln 89)	-			-
70	Transmission Materials & Supplies	(Worksheet C, ln 2.(F))	-	TP	0.00000	-
71	A&G Materials & Supplies	(Worksheet C, ln 3.(F))	-	W/S	0.00000	-
72	Stores Expense	(Worksheet C, ln 4.(F))	-	GP(h)	0.00000	-
73	Prepayments (Account 165) - Labor Allocated	(Worksheet C, ln 8.G)	-	W/S	0.00000	-
74	Prepayments (Account 165) - Gross Plant	(Worksheet C, ln 8.F)	-	GP(h)	0.00000	-
75	Prepayments (Account 165) - Transmission Only	(Worksheet C, ln 8.E)	-	DA	1.00000	-
76	Prepayments (Account 165) - Unallocable	(Worksheet C, ln 8.D)	-	NA	0.00000	-
77	TOTAL WORKING CAPITAL	(sum lns 69 to 76)	-			-
78	IPP CONTRIBUTIONS FOR CONSTRUCTION	(Note F) (Worksheet D, ln 8.B)	-	DA	1.00000	-
79	RATE BASE (sum lns 58, 65, 66, 67, 77, 78)		-			-

AEP East Companies
Transmission Cost of Service
Formula Rate
Utilizing ~~Historic~~Actual/~~Cost Data for Historic Year and~~ Projected ~~Net Plant at Year-End Projected Year~~FERC Form 1 Data
~~COMPANY NAME HERE~~

Line No.	(1) RATE BASE CALCULATION	(2) Data Sources (See "General Notes")	(3) TO Total NOTE C	(4) Allocator		(5) Total Transmission
	GROSS PLANT IN SERVICE					
18	Production	(Worksheet A ln 1.C)	-	NA	0.00000	-
19	Less: Production ARO (Enter Negative)	(Worksheet A ln 2.C)	-	NA	0.00000	-
20	Transmission	(Worksheet A ln 3.C & Ln 142)	-	DA		-
21	Less: Transmission ARO (Enter Negative)	(Worksheet A ln 4.C& Ln 143)	-	TP	0.00000	-
22	Plus: Transmission Plant-in-Service Additions (Worksheet I, ln 21.D)		DA	1.00000		
23	Plus: Additional Trans Plant on Transferred Assets (Worksheet I, ln 22.D)		DA	1.00000		
24	Distribution	(Worksheet A ln 5.C)	-	NA	0.00000	-
25	Less: Distribution ARO (Enter Negative)	(Worksheet A ln 6.C)	-	NA	0.00000	-
26	General Plant	(Worksheet A ln 7.C)	-	W/S	0.00000	-
27	Less: General Plant ARO (Enter Negative)	(Worksheet A ln 8.C)	-	W/S	0.00000	-
28	Intangible Plant	(Worksheet A ln 9.C)	-	W/S	0.00000	-
29	TOTAL GROSS PLANT	(sum lns 18 to 28)	-			-
30	ACCUMULATED DEPRECIATION AND AMORTIZATION					
31	Production	(Worksheet A ln 12.C)	-	NA	0.00000	-
32	Less: Production ARO (Enter Negative)	(Worksheet A ln 13.C)	-	NA	0.00000	-
33	Transmission	(Worksheet A ln 14.C & 28.C)	-	TP1=	0.00000	-
34	Less: Transmission ARO (Enter Negative)	(Worksheet A ln 15.C)	-	TP1=	0.00000	-
35	Plus: Transmission Plant-in-Service Additions (Worksheet I, ln 21.I)	-	DA	1.00000	-	
36	Plus: Additional Projected Deprec on Transferred Assets (Worksheet I, ln 24.D)	-	DA	1.00000	-	
37	Plus: Additional Transmission Depreciation for Projected Year (ln 111)	-	TP1	0.00000	-	
38	Plus: Additional General & Intangible Depreciation for Projected Year (ln 113 + ln 114)	-	W/S	0.00000	-	
39	Plus: Additional Accum Deprec on Transferred Assets (Worksheet I, ln 23.D)	-	DA	1.00000	-	
40	Distribution	(Worksheet A ln 16.C)	-	NA	0.00000	-
41	Less: Distribution ARO (Enter Negative)	(Worksheet A ln 17.C)	-	NA	0.00000	-
42	General Plant	(Worksheet A ln 18.C)	-	W/S	0.00000	-
43	Less: General Plant ARO (Enter Negative)	(Worksheet A ln 19.C)	-	W/S	0.00000	-
44	Intangible Plant	(Worksheet A ln 20.C)	-	W/S	0.00000	-
45	TOTAL ACCUMULATED DEPRECIATION	(sum lns 31 to 44)	-			-
46	NET PLANT IN SERVICE					
47	Production	(ln 18 + ln 19 - ln 31 - ln 32)	-			-
48	Transmission	(ln 20 + ln 21 - ln 33 - ln 34)	-			-
49	Plus: Transmission Plant-in-Service Additions (ln 22 - ln 35)	-				-
50	Plus: Additional Trans Plant on Transferred Assets (ln 23 - ln 36)	-				-
51	Plus: Additional Transmission Depreciation for Projected Year (ln 37)	-				-
52	Plus: Additional General & Intangible Depreciation for Projected Year (ln 38)	-				-
53	Plus: Additional Accum Deprec on Transferred Assets (Worksheet I) (ln 39)	-				-
54	Distribution	(ln 24 + ln 25 - ln 40 - ln 41)	-			-
55	General Plant	(ln 26 + ln 27 - ln 42 - ln 43)	-			-
56	Intangible Plant	(ln 28 - ln 44)	-			-
57	TOTAL NET PLANT IN SERVICE	(sum lns 47 to 56)	-			-
58	DEFERRED TAX ADJUSTMENTS TO RATE BASE	(Note D)				
59	Account No. 281.1 (enter negative)	(Worksheet B, ln 2 & ln 5.C)	-	NA		-
60	Account No. 282.1 (enter negative)	(Worksheet B, ln 7 & ln 10.C)	-	DA		-
61	Account No. 283.1 (enter negative)	(Worksheet B, ln 12 & ln 15.C)	-	DA		-
62	Account No. 190.1	(Worksheet B, ln 17 & ln 20.C)	-	DA		-

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~~63~~	~~Account No. 255 (enter negative)~~	~~(Worksheet B, ln 24 & ln 25.C)~~	~~-~~	~~DA~~		~~-~~
~~64~~	~~TOTAL ADJUSTMENTS~~	~~(sum lns 59 to 63)~~	~~-~~			~~-~~
~~65~~	~~PLANT HELD FOR FUTURE USE~~	~~(Worksheet A ln 29.C & ln 30.C)~~	~~-~~	~~DA~~		~~-~~
~~66~~	~~REGULATORY ASSETS~~	~~(Worksheet A ln 36. (C))~~	~~-~~	~~DA~~		~~-~~
~~67~~	~~WORKING CAPITAL~~	~~(Note E)~~				
~~68~~	~~Cash Working Capital~~	~~(1/8 * ln 88)~~	~~-~~			~~-~~
~~69~~	~~Transmission Materials & Supplies~~	~~(Worksheet C, ln 2.(D))~~	~~-~~	~~TP~~	~~0.00000~~	~~-~~
~~70~~	~~A&G Materials & Supplies~~	~~(Worksheet C, ln 3.(D))~~	~~-~~	~~W/S~~	~~0.00000~~	~~-~~
~~71~~	~~Stores Expense~~	~~(Worksheet C, ln 4.(D))~~	~~-~~	~~GP(h)~~	~~0.00000~~	~~-~~
~~72~~	~~Prepayments (Account 165) - Labor Allocated~~	~~(Worksheet C, ln 6.G)~~	~~-~~	~~W/S~~	~~0.00000~~	~~-~~
~~73~~	~~Prepayments (Account 165) - Gross Plant~~	~~(Worksheet C, ln 6.F)~~	~~-~~	~~GP(h)~~	~~0.00000~~	~~-~~
~~74~~	~~Prepayments (Account 165) - Transmission Only~~	~~(Worksheet C, ln 6.E)~~	~~-~~	~~DA~~	~~1.00000~~	~~-~~
~~75~~	~~Prepayments (Account 165) - Unallocable~~	~~(Worksheet C, ln 6.D)~~	~~-~~	~~NA~~	~~0.00000~~	~~-~~
~~76~~	~~TOTAL WORKING CAPITAL~~	~~(sum lns 68 to 75)~~	~~-~~			~~-~~
~~77~~	~~IPP CONTRIBUTIONS FOR CONSTRUCTION~~	~~(Note F)(Worksheet D, ln 7.B)~~	~~-~~	~~DA~~	~~1.00000~~	~~-~~
~~78~~	~~RATE BASE (sum lns 57, 64, 65, 66, 76, 77)~~		~~-~~		~~-~~	

~~AEP East Companies~~

~~Transmission Cost of Service Formula Rate~~

~~Utilizing Historic Cost Data for Historic Year and Projected Net Plant at Year-End Projected Year~~

COMPANY NAME HERE

Line No.	(1) EXPENSE, TAXES, RETURN & REVENUE REQUIREMENTS CALCULATION	(2) Data Sources (See "General Notes")	(3) TO Total	(4) Allocator		(5) Total Transmission
	OPERATION & MAINTENANCE EXPENSE					
~~79~~80	Production	321.80.b	-			
~~80~~81	Distribution	322.156.b	-			
~~81~~82	Customer Related Expense	322 & 323.164,171,178.b	-			
~~82~~83	Regional Marketing Expenses	322.131.b	-			
~~83~~84	Transmission	321.112.b	-			
~~84~~85	TOTAL O&M EXPENSES	(sum lns ~~79~~80 to ~~83~~84)	-			
~~85~~86	Less: Total Account 561	(Note G) (Worksheet F, ln 14.C)	-			
~~86~~87	Less: Account 565	(Note H) 321.96.b	-			
~~87~~88	Less: ~~State~~ Regulatory Deferrals & Amortizations	(Note I) (Worksheet F, ln 4.C)	-			
~~88~~89	Total O&M Allocable to Transmission	(lns ~~83 - 85~~84 - 86 - 87 - 88)	-	TP	0.00000	-
~~89~~90	Administrative and General	323.197.b (Note J)	-			
~~90~~91	Less: Acct. 924, Property Insurance	323.185.b	-			
~~91~~92	Acct. 9260039 PBOP Expense	PBOP Worksheet O Line 9 & 10, (Note K)	-			
~~92~~93	Acct. 9260057 PBOP Medicare Subsidy	PBOP Worksheet O Line 11, (Note K)	-			
~~93~~94	PBOP Expense Billed From AEPSC	PBOP Worksheet O Line 13, (Note K)	-			
~~94~~95	Acct. 928, Reg. Com. Exp.	323.189.b	-			
~~95~~96	Acct. 930.1, Gen. Advert. Exp.	323.191.b	-			
~~96~~97	Acct. 930.2, Misc. Gen. Exp.	323.192.b	-			
~~97~~98	Balance of A & G	(ln ~~89~~90 - sum ln ~~90~~91 to ln ~~96~~97)	-	W/S	0.00000	-
~~98~~99	Plus: Acct. 924, Property Insurance	(ln ~~90~~91)	-	GP(h)	0.00000	-
~~99~~100	Acct. 928 - Transmission Specific	Worksheet F ln 20.(E) (Note L)	-	TP	0.00000	-
~~100~~101	Acct 930.1 - Only safety related ads -Direct	Worksheet F ln 37.(E) (Note L)	-	TP	0.00000	-
~~101~~102	Acct 930.2 - Misc Gen. Exp. - Trans	Worksheet F ln 43.(E) (Note L)	-	DA	1.00000	-
~~102~~103	Settlement Approved PBOP Recovery	PBOP Worksheet O, Col. C, Line 1, (Note M)	-	W/S	0.00000	-
~~103~~104	A & G Subtotal	(sum lns ~~97~~98 to ~~102~~103)	-			-
~~104~~105	O & M EXPENSE SUBTOTAL	(ln ~~88~~89 + ln ~~103~~104)	-			-
~~105~~106	~~Plus: TEA Settlement in Account 565~~Line Deliberately Left Blank	~~Company Records (Note H)~~	-	~~DA~~	~~1.00000~~	-
~~106~~107	Plus: Transmission Lease Payments To Affiliates in Acct 565	(Company Records) (Note H)	-	DA	1.00000	-
~~107~~108	TOTAL O & M EXPENSE	(ln ~~104 + ln~~ 105 + ln ~~106~~107)	-			-
~~108~~109	DEPRECIATION AND AMORTIZATION EXPENSE					
~~109~~110	Production	336.2-6.f	-	NA	0.00000	-
~~110~~111	Distribution	336.8.f	-	NA	0.00000	-
~~111~~112	Transmission	336.7.f	-	TP1	0.00000	-
~~112~~113	~~Plus: Transmission Plant-in-Service Additions (Worksheet I ln 21.I)~~ Line Deliberately Left Blank			~~DA~~	~~1.00000~~	
~~113~~114	General	336.10.f	-	W/S	0.00000	-
~~114~~115	Intangible	336.1.f	-	W/S	0.00000	-
~~115~~116	TOTAL DEPRECIATION AND AMORTIZATI0N	(~~Lns 109+~~Ln 110+111+112+113+114+115)	-			-
~~116~~117	TAXES OTHER THAN INCOME	(Note N)				
~~117~~118	Labor Related					
~~118~~119	Payroll	Worksheet H ln 24.(D)	-	W/S	0.00000	-
~~119~~120	Plant Related					
~~120~~121	Property	Worksheet H ln 24.(C) & ln 59.(C)	-	DA		-0-
~~121~~122	Gross Receipts/Sales & Use	Worksheet H ln 24.(F)	-	NA	0.00000	-
~~122~~123	Other	Worksheet H ln 24.(E)	-	GP(h)	0.00000	-
~~123~~124	TOTAL OTHER TAXES	(sum lns ~~118~~119 to ~~122~~123)	-			-
~~124~~125	INCOME TAXES	(Note O)				
~~125~~126	T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =		0.00%			

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~~126~~1 27	EIT=(T/(1-T)) * (1-(WCLTD/WACC)) =		0.00%			
~~127~~1 28	where WCLTD=(ln ~~162~~167) and WACC = (ln ~~165~~170)					
~~128~~1 29	and FIT, SIT & p are as given in Note O.					
~~129~~1 30	GRCF=1 / (1 - T) = (from ln ~~125~~126)	-	-			
~~130~~1 31	Amortized Investment Tax Credit (enter negative)	(FF1 p.114, ln 19.c)	-			
132	Excess Deferred Income Tax	(Note U)	-	DA	1.00000	-
133	Tax Effect of Permanent Differences	(Note U)	-	DA	1.00000	-
~~131~~1 34	Income Tax Calculation	(ln ~~126~~127 * ln ~~134~~139)	-			-
~~132~~1 35	ITC adjustment	(ln ~~129~~130 * ln ~~130~~131)	-	-NP(h)	0.00000	-
136	Excess Deferred Income Tax	(ln 130 * ln 132)	-			-
137	Tax Effect of Permanent Differences	(ln 130 * ln 133)	-			-
~~133~~1 38	TOTAL INCOME TAXES	(sum lns ~~131~~134 to ~~132~~137)	-			-
~~134~~1 39	RETURN ON RATE BASE (Rate Base~~ * ~~*WACC)	(ln ~~78~~79 * ln ~~165~~170)	-			-
~~135~~1 40	INTEREST ON IPP CONTRIBUTION FOR CONST. (Note F) (Worksheet D, ln 2.(B))		-	-DA	1.00000	-
~~136~~1 41	(Gains~~)/~~) / Losses on Sales of Plant Held for Future Use (Worksheet N, ln 4, Cols. ((F) & (H))			-		-
~~137~~1 42	Tax Impact on ~~(Gains) / Losses~~Net Loss / (Gain) on Sales of Plant Held for Future Use (ln ~~136 * ln126~~141 * ln 127)			-		-
~~138~~1 43	TOTAL REVENUE REQUIREMENT (sum lns ~~107, 115, 123, 133, 134, 135, 136, 137~~108, 116, 124, 138, 139, 140, 141, 142)	-	-	-		-

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AEP East Companies
Transmission Cost of Service Formula Rate
Utilizing ~~Historic Cost Data for Historic Year and~~ Actual/Projected ~~Net Plant at Year-End Projected Year~~FERC Form 1 Data
COMPANY NAME HERE

SUPPORTING CALCULATIONS

ln No.	TRANSMISSION PLANT INCLUDED IN PJM TARIFF					
~~139~~144	Total transmission plant	(ln ~~20~~21)				-
~~140~~145	Less transmission plant excluded from PJM Tariff (Note P)					-
~~141~~146	Less transmission plant included in OATT Ancillary Services (Worksheet A, ln 23, Col. (~~C~~E)) (Note Q)					-
~~142~~147	Transmission plant included in PJM Tariff	(ln ~~139~~144 - ln ~~140~~145 - ln ~~141~~146)				-
~~143~~148	Percent of transmission plant in PJM Tariff	(ln ~~142~~147 / ln ~~139~~144)			TP =	0.~~000000~~0000

ln No.	WAGES & SALARY ALLOCATOR (W/S)	(Note R)	Direct Payroll	Payroll Billed from AEP Service Corp.	Total			
~~144~~149	Production	354.20.b	~~0~~	~~0~~	-	NA	0.00000	-
~~145~~150	Transmission	354.21.b	~~0~~	~~0~~	-	TP	0.00000	-
~~146~~151	Regional Market Expenses	354.22.b	~~0~~	~~0~~	-	NA	0.00000	-
~~147~~152	Distribution	354.23.b	~~0~~	~~0~~	-	NA	0.00000	-
~~148~~153	Other (Excludes A&G)	354.24,25,26.b	~~0~~	~~0~~	-	NA	0.00000	-
~~149~~154	Total	(sum lns ~~145~~150 to ~~149~~154)	0	0	0			-
~~150~~155	Transmission related amount					W/S=		0.~~000000~~0000

ln No.	WEIGHTED AVERAGE COST OF CAPITAL (WACC)		$
~~151~~156			
~~152~~157	Long Term Interest	(Worksheet ~~L~~M, ln. ~~35~~21, col. (~~D~~E))	-
~~153~~158	Preferred Dividends	(Worksheet ~~L~~M, ln. ~~40~~55, col. (~~D~~E))	-
~~154~~159	Development of Common Stock:		
~~155~~160			
~~156~~161	Proprietary Capital	~~(FF1 p 112, Ln 16.c)~~(Worksheet M, ln. 1, col. (E))	
~~157~~162	Less: Preferred Stock	~~(FF1 p 112, Ln 3.c)~~(Worksheet M, ln. 2, col. (E))	
~~158~~163	Less: Account 216.1	~~(FF1 p 112, Ln 12.c)~~(Worksheet M, ln. 3, col. (E))	
~~159~~164	Less: Account 219	~~(FF1 p 112, Ln 15.c)~~(Worksheet M, ln. 4, col. (E))	
~~160~~165	Common Stock	(ln ~~156~~161 - ln ~~157~~162 - ln ~~158~~163 - ln ~~159~~164)	-

ln No.		$	%	Cost (Note S)	Weighted
~~161~~166					
~~162~~167	Long Term Debt (Note T) Worksheet ~~L~~M, ln ~~35~~11, ln 22, col. (~~B~~E))	-	0.00%	-	0.0000
~~163~~168	Preferred Stock (ln ~~157~~162)	-	0.00%	-	0.0000
~~164~~169	Common Stock (ln ~~160~~165)	-	0.00%	~~0.00%~~	0.0000
~~165~~170	Total (Sum lns ~~162~~167 to ~~164~~169)	-		WACC =	0.0000

AEP East Companies
Transmission Cost of Service Formula Rate
Utilizing ~~Historic Cost Data for Historic Year and~~ Actual/Projected ~~Net Plant at Year-End Projected Year~~FERC Form 1 Data
COMPANY NAME HERE

Letter	**Notes**
	General Notes: a) References to data from Worksheets are indicated as: Worksheet X, Line#.Column.X

A Revenue credits include:
1) Forfeited Discounts.
2) Miscellaneous Service Revenues.
3) Rental revenues earned on assets included in the rate base.
4) Revenues for associated business projects provided by employees whose labor and overhead costs are in the transmission cost of service.
5) Other electric revenues.
6) Revenues for grandfathered PTP contracts included in the load divisor.
7) If AEP East companies have any directly assigned transmission facilities, the revenue credits in the AEP East formula rate shall include all revenues associated with those directly assigned transmission facilities, irrespective of whether the loads of the customer are included in the formula rate divisor; provided however, such addition to revenue credits shall not be reflected if the costs of such directly assigned transmission facilities are not included in the transmission plant balances on which the formula rate ATRR is based.~~6) Revenues for grandfathered PTP contracts included in the load divisor.~~
See Worksheet E for details.

B The annual and monthly net plant carrying charges on page 1 are used to compute the revenue requirement for RTEP sponsored upgrades or those projects receiving approved incentive-ROE's. Interest will be calculated based on Worksheet Q and any over under recovery will be filed and posted as part of the informational filing.

C Transmission Plant ~~balances~~Balances in this study are projected ~~as~~or actual average beginning of ~~December 31, Projected Year. Other ratebase amounts are as~~year end of ~~December 31, Historic Year~~year balances.

D The total-company balances shown for Accounts 281, 282, 283, 190 only reflect ADIT that relates to utility operations. The balance of Account 255 is reduced by prior flow ~~throughs~~through and is completely excluded if the utility chose to utilize amortization of tax credits against FIT expense. An exception to this is pre-1971 ITC balances, which are required to be taken as an offset to rate base. Account 281 is not allocated. In compliance with FERC Rulemaking the calculation of ADIT in the annual projection will be performed in accordance with IRS regulation Section1.167(I)-I(h)(6)(ii). RM02-7-000, Asset Retirement Obligation deferrals have been removed from ratebase. Transmission ADIT allocations are shown on WS B.
The company will not include the ADIT portion of deferred hedge gains and losses in rate base.Detailed balances for the projected or actual period, distinguished between utility and non-utility balances, will be filed and posted as part of the information filing.
~~The company will not include the ADIT portion of deferred hedge gains and losses in rate base.~~

E Cash Working Capital assigned to transmission is one-eighth of O&M allocated to transmission, as shown on line ~~88.~~ 89. It excludes:
1) Load Scheduling & Dispatch Charges in account 561 that are collected in the OATT Ancilliary Services Revenue, as shown on line ~~85~~86.
~~2) AEP transmission equalization transfers, as shown on line 86~~2) Costs of Transmission of Electricity by Others, as described in Note H.
3) The impact of state regulatory deferrals and amortizations, as shown on line ~~87~~88
4) All A&G Expenses, as shown on line ~~103~~104.

F Consistent with Paragraph 657 of Order 2003-A, the amount on line ~~77~~78 is equal to the balance of IPP System Upgrade Credits owed to transmission customers that made contributions toward the construction of System upgrades, and includes accrued interest and unreturned balance of contributions. The annual interest expense is included on line ~~135~~140.

G Removes from the cost of service the Load Scheduling and Dispatch expenses booked to accounts 561.1 through 561.8. Expenses recorded in these accounts, with the exception of 561.4 & 561.8 (lines ~~15 &~~ 16 & 17 above) are recovered in Schedule 1A, OATT ancillary services rates. See Worksheet F, lines 5 through 14, for descriptions and the Form 1 Source of these accounts' balances.

H Removes cost of transmission service provided by others to determine the basis of cash working capital on line ~~88~~89. To the extent such service is incurred to provide the PJM service at issue, e.g. ~~transmission equalization agreement~~lease payments to affiliates, such ~~costs are~~cost is added back on ~~lines 105 and 106~~line 107 to determine the total O&M collected in the formula. The ~~amounts~~amount on ~~lines 105 and 106 are~~line 107 is also excluded in the calculation of the FCR percentage calculated on lines ~~5~~6 through ~~11~~12. The addbacks on line 107 of activity recorded in 565 represents inter-company sales or purchases of transmission capacity necessary to meet each AEP company's transmission load relative to their available transmission capacity. The company records referenced on line 107 is the COMPANY NAME HERE general ledger.
~~The addbacks on lines 105 and 106 of activity recorded in 565 represents inter-company sales or purchases of transmission capacity necessary to meet each AEP company's transmission load relative to their available transmission capacity.~~
~~The company records referenced on lines 105 and 106 is the COMPANY NAME HERE general ledger.~~

I Removes the impact of state regulatory deferrals or their amortization from Transmission O&M expense.

~~J~~ ~~General Plant and Administrative & General expenses, other than in accounts 924, 928, and 930, will be functionalized based on the Wages & Salaries "W/S" allocator. The allocation basis for accounts 924, 928 and 930 are separately presented in the formula. A change in the allocation method for an account must be approved via a 205 filing with the FERC.~~

~~K~~ ~~These deductions on lines 91 through 93 are to remove from the cost of service the expenses recorded by the company for Postemployment Benefits Other than Pensions (PBOP). See Note M below for the recoverable PBOP expense.~~

~~L~~ ~~Expenses reported for these A&G accounts will be included in the cost of service only to the extent they are directly assignable to transmission service. Worksheet F allocates these expense items. Acct 928 Includes Regulatory Commission expenses itemized in FERC Form 1 at page 351, column H. FERC Assessment Fees and Annual Charges shall not be allocated to transmission. Only safety-related and educational advertising costs in Account 930.1 are included in the TCOS. Account 930.2 includes the expenses incurred by the transmission function for Associated Business Development revenues given as a credit to the TCOS on Worksheet E.~~

~~M~~ ~~See note K above. Per the settlement in Docket ER08-1329, recoverable PBOP expense is based on an annual total for the operating companies that is ratioed to them based on the total of actual annual PBOP costs, including charges from the AEP Service Corportation. The calculation of the recoverable amount for each company is shown on Worksheet O, and the process for updating the annual total is documented on Attachment F, Allowable PBOP Expense Formula.~~

~~N~~ ~~Includes only FICA, unemployment, highway, property and other assessments charged in the current year. Gross receipts, sales & use and taxes related to income are excluded.~~

~~O~~ ~~The currently effective income tax rate, where FIT is the Federal income tax rate; SIT is the State income tax rate, and p = the percentage of federal income tax deductible for state income taxes. See Worksheet G for the development of the Company's composite SIT. A utility that elected to utilize amortization of tax credits against taxable income, rather than book tax credits to Account No. 255 and reduce rate base, must reduce its income tax expense by the amount of the Amortized Investment Tax Credit (Form 1, 266.8.f) (ln 130) multiplied by (1/1-T) . If the applicable tax rates are zero enter 0.~~

~~Inputs Required:~~	~~FIT =~~		~~0.00%~~	
	~~SIT =~~	~~0.00%~~		~~(State Income Tax Rate or Composite SIT. Worksheet G))~~
	~~p =~~	~~0.00%~~		~~(percent of federal income tax deductible for state purposes)~~

~~P~~ ~~Removes plant excluded from the OATT because it does not meet the PJM's definition of Transmission Facilities or is otherwise ineligible to be recovered under the OATT.~~

~~Q~~ ~~Removes transmission plant (e.g. step-up transformers) included in the development of OATT ancillary service rates and not already removed for reasons indicated in Note P.~~

~~R~~ ~~Includes functional wages & salaries billed by AEP Service Corporation for support of the operating company.~~

~~S~~ ~~Long Term Debt cost rate = long-term interest (ln 153) / long term debt (ln 162). Preferred Stock cost rate = preferred dividends (ln 154) / preferred outstanding (ln 163).~~
~~Common Stock cost rate (ROE) = 0%, the rate accepted by FERC in Docket No. ER08-1329. It includes an additional 50 basis points for PJM RTO~~

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~~membership.~~

~~In the Projected & Historic templates, the interest expense on long-term debt is the sum of a full year's interest expense at the coupon rate for each issuance outstanding as of December 31 of the historic year. The projected expense for variable rate debt will be based on the effective rate at December 31. These conventions ensure that the expense used in the projection will reflect a full year, similar to the actual expense that will appear in the subsequent true-up of the projection, and minimize the impact on the true-up of using a partial year interest expense. The projection will reflect the actual historic-year expense recorded for issuance expenses, discounts and premiums, and gains or losses on reacquired debt. Eligible hedging gains or losses will be limited to five basis points of the projected capital structure. Details and calculations are shown on Worksheet L.~~

~~T The Long Term Debt balance for I&M includes the accumulated balance of principle and related interest for Spent Nuclear Fuel Disposal Costs collected prior to April 7, 1983. This total balance of ________ at 12/31/___ is not included in the balance in line 162 above.~~

~~U This note only applies to the true-up template.~~

~~AEP East Companies~~

~~Transmission Cost of Service Formula Rate~~

~~Utilizing Historic Cost Data for Historic Year with Year-End Rate Base Balances~~

~~**COMPANY NAME HERE**~~

~~Line No.~~					~~Transmission Amount~~
~~166~~	~~REVENUE REQUIREMENT (w/o incentives)~~	~~(ln 303)~~			~~$0~~
			~~Total~~	~~Allocator~~	
~~167~~	~~REVENUE CREDITS~~	~~(Note A) (Worksheet E)~~	~~-~~	~~DA 1.000~~	~~$ -~~
~~168~~	~~REVENUE REQUIREMENT For All Company Facilities~~	~~(ln 166 less ln 167)~~			~~$ -~~

~~**MEMO: The Carrying Charge Calculations on lines 171 to 176 below are used in calculating project revenue requirements billed through PJM Schedule 12, Transmission Enhancement Charges. The total non-incentive revenue requirements for these projects shown on line 169 is included in the total on line 168.**~~

~~169~~	~~Not applicable on this template~~			
~~170~~	~~NET PLANT CARRYING CHARGE w/o intra-AEP charges or credits or ROE incentives (Note B)~~			
~~171~~	~~Annual Rate~~	~~((ln 166 - ln 270 - ln 271)/ ln 213 x 100)~~		~~0.00%~~
~~172~~	~~Monthly Rate~~	~~(ln 171 / 12)~~		~~0.00%~~
~~173~~	~~NET PLANT CARRYING CHARGE ON LINE 171 , w/o depreciation or ROE incentives (Note B)~~			
~~174~~	~~Annual Rate~~	~~((ln 166 - ln 270 - ln 271 - ln 276) / ln 213 x 100)~~		~~0.00%~~
~~175~~	~~NET PLANT CARRYING CHARGE ON LINE 174, w/o Return, income taxes or ROE incentives (Note B)~~			
~~176~~	~~Annual Rate~~	~~((ln 166 - ln 270 - ln 271 - ln 276 - ln 298 - ln 299) / ln 213 x 100)~~		~~0.00%~~
~~177~~	~~Not applicable on this template~~			
~~178~~	~~**REVENUE REQUIREMENT FOR SCHEDULE 1A CHARGES**~~		~~- - - -~~	
~~179~~	~~Total Load Dispatch & Scheduling (Account 561)~~	~~Line 250 Below~~		~~-~~
~~180~~	~~Less: Load Dispatch - Scheduling, System Control and Dispatch Services (321.88.b)~~			~~-~~
~~181~~	~~Less: Load Dispatch - Reliability, Planning & Standards Development Services (321.92.b)~~			~~-~~
~~182~~	~~Total 561 Internally Developed Costs~~	~~(Line 179 - Line 180 - Line 181)~~		~~-~~

AEP East Companies
Transmission Cost of Service Formula Rate
Utilizing Historic Cost Data for Historic Year with Year-End Rate Base Balances
COMPANY NAME HERE

Line No.	(1) RATE BASE CALCULATION	(2) Data Sources (See "General Notes")	(3) TO Total NOTE C	(4) Allocator		(5) Total Transmission
	GROSS PLANT IN SERVICE					
183	Production	(Worksheet A ln 1.C)	-	NA	0.00000	-
184	Less: Production ARO (Enter Negative)	(Worksheet A ln 2.C)	-	NA	0.00000	-
185	Transmission	(Worksheet A ln 3.C & Ln 307)	-	DA		-
186	Less: Transmission ARO (Enter Negative)	(Worksheet A ln 4.C& Ln 308)	-	TP	0.00000	-
187	Plus: Transmission Plant-in-Service Additions (Worksheet I)		N/A	NA	0.00000	N/A
188	Plus: Additional Trans Plant on Transferred Assets (Worksheet I)		N/A	NA	0.00000	N/A
189	Distribution	(Worksheet A ln 5.C)	-	NA	0.00000	-
190	Less: Distribution ARO (Enter Negative)	(Worksheet A ln 6.C)	-	NA	0.00000	-
191	General Plant	(Worksheet A ln 7.C)	-	W/S	0.00000	-
192	Less: General Plant ARO (Enter Negative)	(Worksheet A ln 8.C)	-	W/S	0.00000	-
193	Intangible Plant	(Worksheet A ln 9.C)	-	W/S	0.00000	-
194	TOTAL GROSS PLANT	(sum lns 183 to 193)	-	GP(h)=	0.000000	-
				GTD=	-	
195	ACCUMULATED DEPRECIATION AND AMORTIZATION					
196	Production	(Worksheet A ln 12.C)	-	NA	0.00000	-
197	Less: Production ARO (Enter Negative)	(Worksheet A ln 13.C)	-	NA	0.00000	-
198	Transmission	(Worksheet A ln 14.C & 28.C)	-	TP1=	0.00000	-
199	Less: Transmission ARO (Enter Negative)	(Worksheet A ln 15.C)	-	TP1=	0.00000	-
200	Plus: Transmission Plant-in-Service Additions (Worksheet I)		N/A	DA	1.00000	N/A
201	Plus: Additional Projected Deprec on Transferred Assets (Worksheet I)		N/A	DA	1.00000	N/A
202	Plus: Additional Transmission Depreciation for Historic Year+1 (ln 276)		N/A	TP1	0.00000	N/A
203	Plus: Additional General & Intangible Depreciation for Historic Year+1 (ln 275 + ln 276)		N/A	W/S	0.00000	N/A
204	Plus: Additional Accum Deprec on Transferred Assets (Worksheet I)		N/A	DA	1.00000	N/A
205	Distribution	(Worksheet A ln 16.C)	-	NA	0.00000	-
206	Less: Distribution ARO (Enter Negative)	(Worksheet A ln 17.C)	-	NA	0.00000	-
207	General Plant	(Worksheet A ln 18.C)	-	W/S	0.00000	-
208	Less: General Plant ARO (Enter Negative)	(Worksheet A ln 19.C)	-	W/S	0.00000	-
209	Intangible Plant	(Worksheet A ln 20.C)	-	W/S	0.00000	-
210	TOTAL ACCUMULATED DEPRECIATION	(sum lns 196 to 209)	-			-
211	NET PLANT IN SERVICE					
212	Production	(ln 183 + ln 184 - ln 196 - ln 197)	-			-
213	Transmission	(ln 185 + ln 186 - ln 198 - ln 199)	-			-
214	Plus: Transmission Plant-in-Service Additions (ln 187 - ln 200)		N/A			N/A
215	Plus: Additional Trans Plant on Transferred Assets (ln 188 - ln 201)		N/A			N/A
216	Plus: Additional Transmission Depreciation for Historic Year+1 (-ln 202)		N/A			N/A
217	Plus: Additional General & Intangible Depreciation for Historic Year+1 (-ln 203)		N/A			N/A
218	Plus: Additional Accum Deprec on Transferred Assets (Worksheet I) (-ln 204)		N/A			N/A
219	Distribution	(ln 189 + ln 190 - ln 205 - ln 206)	-			-
220	General Plant	(ln 191 + ln 192 - ln 207 - ln 208)	-			-
221	Intangible Plant	(ln 193 - ln 209)	-			-
222	TOTAL NET PLANT IN SERVICE	(sum lns 212 to 221)	-	NP(h)=	0.000000	-
223	DEFERRED TAX ADJUSTMENTS TO RATE BASE	(Note D)				
224	Account No. 281.1 (enter negative)	(Worksheet B, ln 2 & ln 5.C)	-	NA		-
225	Account No. 282.1 (enter negative)	(Worksheet B, ln 7 & ln 10.C)	-	DA		-
226	Account No. 283.1 (enter negative)	(Worksheet B, ln 12 & ln 15.C)	-	DA		-
227	Account No. 190.1	(Worksheet B, ln 17 & ln 20.C)	-	DA		-
228	Account No. 255 (enter negative)	(Worksheet B, ln 24 & ln 25.C)	-	DA		-
229	TOTAL ADJUSTMENTS	(sum lns 224 to 228)	-			-
230	PLANT HELD FOR FUTURE USE	(Worksheet A ln 29.C & ln 30.C)	-	DA		-
231	REGULATORY ASSETS	(Worksheet A ln 36. (C))	-	DA		-
232	WORKING CAPITAL	(Note E)				
233	Cash Working Capital	(1/8 * ln 253)	-			-
234	Transmission Materials & Supplies	(Worksheet C, ln 2.(D))	-	TP	0.00000	-
235	A&G Materials & Supplies	(Worksheet C, ln 3.(D))	-	W/S	0.00000	-
236	Stores Expense	(Worksheet C, ln 4.(D))	-	GP(h)	0.00000	-
237	Prepayments (Account 165) - Labor Allocated	(Worksheet D, ln 6.G)	-	W/S	0.00000	-
238	Prepayments (Account 165) - Gross Plant	(Worksheet D, ln 6.F)	-	GP(h)	0.00000	-
239	Prepayments (Account 165) - Transmission Only	(Worksheet D, ln 6.E)	-	DA	1.00000	-
240	Prepayments (Account 165) - Unallocable	(Worksheet D, ln 6.D)	-	NA	0.00000	-
241	TOTAL WORKING CAPITAL	(sum lns 233 to 240)	-			-
242	IPP CONTRIBUTIONS FOR CONSTRUCTION	(Note F) (Worksheet D, ln 7.B)	-	DA	1.00000	-
243	RATE BASE (sum lns 222, 229, 230, 231, 241, 242)		-			-

AEP East Companies
Transmission Cost of Service Formula Rate
Utilizing Historic Cost Data for Historic Year with Year-End Rate Base Balances
COMPANY NAME HERE

Line No.	(1) EXPENSE, TAXES, RETURN & REVENUE REQUIREMENTS CALCULATION	(2) Data Sources (See "General Notes")	(3) TO Total	(4) Allocator		(5) Total Transmission
	OPERATION & MAINTENANCE EXPENSE					
244	Production	321.80.b	-			
245	Distribution	322.156.b	-			
246	Customer Related Expense	322 & 323.164,171,178.b	-			
247	Regional Marketing Expenses	322.131.b	-			
248	Transmission	321.112.b	-			
249	TOTAL O&M EXPENSES	(sum lns 244 to 248)	-			
250	Less: Total Account 561	(Note G) (Worksheet F, ln 14.C)	-			
251	Less: Account 565	(Note H) 321.96.b	-			
252	Less: Regulatory Deferrals & Amortizations	(Note I) (Worksheet F, ln 4.C)	-			
253	Total O&M Allocable to Transmission	(lns 248 - 250 - 251 - 252)	-	TP	0.00000	-
254	Administrative and General	323.197.b (Note J)	-			
255	Less: Acct. 924, Property Insurance	323.185.b	-			
256	Acct. 9260039 PBOP Expense	PBOP Worksheet O Line 9 & 10, (Note K)	-			
257	Acct. 9260057 PBOP Medicare Subsidy	PBOP Worksheet O Line 11, (Note K)	-			
258	PBOP Expense Billed From AEPSC	PBOP Worksheet O Line 13, (Note K)	-			
259	Acct. 928, Reg. Com. Exp.	323.189.b	-			
260	Acct. 930.1, Gen. Advert. Exp.	323.191.b	-			
261	Acct. 930.2, Misc. Gen. Exp.	323.192.b	-			
262	Balance of A & G	(ln 254 - sum ln 255 to ln 261)	-	W/S	0.00000	-
263	Plus: Acct. 924, Property Insurance	(ln 255)	-	GP(h)	0.00000	-
264	Acct. 928 - Transmission Specific	Worksheet F ln 20.(E) (Note L)	-	TP	0.00000	-
265	Acct 930.1 - Only safety related ads -Direct	Worksheet F ln 37.(E) (Note L)	-	TP	0.00000	-
266	Acct 930.2 - Misc Gen. Exp. - Trans	Worksheet F ln 43.(E) (Note L)	-	DA	1.00000	-
267	Settlement Approved PBOP Recovery	PBOP Worksheet O, Col. C, Line 1, (Note M)	-	W/S	0.00000	-
268	A & G Subtotal	(sum lns 262 to 267)	-			-
269	O & M EXPENSE SUBTOTAL	(ln 253 + ln 268)	-			-
270	Plus: TEA Settlement in Account 565	Company Records (Note H)	-	DA	1.00000	-
271	Plus: Transmission Lease Payments To Affiliates in Acct 565 (Company Records) (Note H)		-	DA	1.00000	-
272	TOTAL O & M EXPENSE	(ln 269 + ln 270 + ln 271)	-			-
273	DEPRECIATION AND AMORTIZATION EXPENSE					
274	Production	336.2-6.f	-	NA	0.00000	-
275	Distribution	336.8.f	-	NA	0.00000	-
276	Transmission	336.7.f	-	TP1	0.00000	-
277	Plus: Transmission Plant-in-Service Additions (Worksheet I)		N/A			N/A
278	General	336.10.f	-	W/S	0.00000	-
279	Intangible	336.1.f	-	W/S	0.00000	-
280	TOTAL DEPRECIATION AND AMORTIZATION	(Ln 274+275+276+277+278+279)	-			-
281	TAXES OTHER THAN INCOME	(Note N)				
282	Labor Related					
283	Payroll	Worksheet H ln 24.(D)	-	W/S	0.00000	-
284	Plant Related					
285	Property	Worksheet H ln 24.(C) & ln 59.(C)	-	DA		0
286	Gross Receipts/Sales & Use	Worksheet H ln 24.(F)	-	NA	0.00000	-
287	Other	Worksheet H ln 24.(E)	-	GP(h)	0.00000	-
288	TOTAL OTHER TAXES	(sum lns 283 to 287)	-			-
289	INCOME TAXES	(Note O)				
290	T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =		0.00%			
291	EIT=(T/(1-T)) * (1-(WCLTD/WACC)) =		0.00%			
292	where WCLTD=(ln 327) and WACC = (ln 330)					
293	and FIT, SIT & p are as given in Note O.					
294	GRCF=1 / (1 - T) = (from ln 290)		-			
295	Amortized Investment Tax Credit (enter negative)	(FF1 p.114, ln 19.c)	-			
296	Income Tax Calculation	(ln 291 * ln 299)	-			-
297	ITC adjustment	(ln 294 * ln 295)	-	NP(h)	0.00000	-
298	TOTAL INCOME TAXES	(sum lns 296 to 297)	-			-
299	RETURN ON RATE BASE (Rate Base*WACC)	(ln 243 * ln 330)	-			-
300	INTEREST ON IPP CONTRIBUTION FOR CONST. (Note F) (Worksheet D, ln 2.(B))		-	DA	1.00000	-
301	(Gains) / Losses on Sales of Plant Held for Future Use (Worksheet N, ln 4, Cols. ((F) & (H))				-	-
302	Tax Impact on Net Loss / (Gain) on Sales of Plant Held for Future Use (ln 301 * ln291)				-	-
303	TOTAL REVENUE REQUIREMENT (sum lns 272, 280, 288, 298, 299, 300, 301, 302)		-			-

~~AEP East Companies~~
~~Transmission Cost of Service Formula Rate~~
~~Utilizing Historic Cost Data for Historic Year with Year-End Rate Base Balances~~
~~COMPANY NAME HERE~~
~~**SUPPORTING CALCULATIONS**~~

~~ln No.~~	~~TRANSMISSION PLANT INCLUDED IN PJM TARIFF~~								
~~304~~	~~Total transmission plant~~	~~(ln 185)~~							~~-~~
~~305~~	~~Less transmission plant excluded from PJM Tariff (Note P)~~								~~-~~
~~306~~	~~Less transmission plant included in OATT Ancillary Services (Worksheet A, ln 23, Col. (C)) (Note Q)~~								~~-~~
~~307~~	~~Transmission plant included in PJM Tariff~~		~~(ln 304 - ln 305 - ln 306)~~						~~-~~
~~308~~	~~Percent of transmission plant in PJM Tariff~~		~~(ln 307 / ln 304)~~					~~TP=~~	~~**0.00000**~~
~~309~~	~~WAGES & SALARY ALLOCATOR (W/S)~~	~~(Note R)~~	~~Direct Payroll~~	~~Payroll Billed from AEP Service Corp.~~	~~Total~~				
~~310~~	~~Production~~	~~354.20.b~~	~~-~~	~~-~~	~~-~~	~~NA~~	~~0.00000~~		~~-~~
~~311~~	~~Transmission~~	~~354.21.b~~	~~-~~	~~-~~	~~-~~	~~TP~~	~~0.00000~~		~~-~~
~~312~~	~~Regional Market Expenses~~	~~354.22.b~~	~~-~~	~~-~~	~~-~~	~~NA~~	~~0.00000~~		~~-~~
~~313~~	~~Distribution~~	~~354.23.b~~	~~-~~	~~-~~	~~-~~	~~NA~~	~~0.00000~~		~~-~~
~~314~~	~~Other (Excludes A&G)~~	~~354.24,25,26.b~~	~~-~~	~~-~~	~~-~~	~~NA~~	~~0.00000~~		~~-~~
~~315~~	~~Total~~	~~(sum lns 310 to 314)~~	~~0~~	~~0~~	~~0~~				~~-~~
~~316~~	~~Transmission related amount~~							~~W/S=~~	~~**0.00000**~~
~~317~~	~~WEIGHTED AVERAGE COST OF CAPITAL (WACC)~~								~~$~~
~~318~~	~~Long Term Interest~~	~~(Worksheet L, ln. 35, col. (D))~~							~~-~~
~~319~~	~~Preferred Dividends~~	~~(Worksheet L, ln. 40, col. (D))~~							~~-~~
~~320~~	~~Development of Common Stock:~~								
~~321~~	~~Proprietary Capital~~	~~(FF1 p 112, Ln 16.c)~~							~~-~~
~~322~~	~~Less: Preferred Stock~~	~~(FF1 p 112, Ln 3.c)~~							~~-~~
~~323~~	~~Less: Account 216.1~~	~~(FF1 p 112, Ln 12 .c)~~							~~-~~
~~324~~	~~Less: Account 219~~	~~(FF1 p 112, Ln 15.c)~~							~~-~~
~~325~~	~~Common Stock~~	~~(ln 321 - ln 322 - ln 323 - ln 324)~~							~~-~~
~~326~~				~~$~~	~~%~~	~~Cost (Note S)~~			~~Weighted~~
~~327~~	~~Long Term Debt (Note T) Worksheet L, ln 35, col. (B))~~			~~-~~	~~0.00%~~	~~-~~			~~0.0000~~
~~328~~	~~Preferred Stock (ln 322)~~			~~-~~	~~0.00%~~	~~-~~			~~0.0000~~
~~329~~	~~Common Stock (ln 325)~~			~~-~~	~~0.00%~~	~~-~~			~~0.0000~~
~~330~~	~~Total (Sum lns 327 to 329)~~			~~-~~				~~WACC=~~	~~**0.0000**~~

~~AEP East Companies~~
~~Transmission Cost of Service Formula Rate~~
~~Utilizing Historic Cost Data for Historic Year with Year-End Rate Base Balances~~
~~COMPANY NAME HERE~~

~~**Letter**~~ ~~**Notes**~~

~~General Notes: a) References to data from Worksheets are indicated as: Worksheet X, Line#.Column.X~~

~~A~~ ~~Revenue credits include:~~
~~1) Forfeited Discounts.~~
~~2) Miscellaneous Service Revenues.~~
~~3) Rental revenues earned on assets included in the rate base.~~
~~4) Revenues for associated business projects provided by employees whose labor and overhead costs are in the transmission cost of service.~~
~~5) Other electric revenues.~~
~~6) Revenues for grandfathered PTP contracts included in the load divisor.~~
~~See Worksheet E for details.~~

~~B~~ ~~The annual and monthly net plant carrying charges on page 1 are used to compute the revenue requirement for RTEP sponsored upgrades or those projects receiving approved incentive ROE's.~~

~~C~~ ~~Transmission Plant balances in this study are historic as of December 31, Historic Year.~~

~~D~~ ~~The total-company balances shown for Accounts 281, 282, 283, 190 only reflect ADIT that relates to utility operations. The balance of Account 255 is reduced by prior flow throughs and is completely excluded if the utility chose to utilize amortization of tax credits against FIT expense. An exception to this is pre-1971 ITC balances, which are required to be taken as an offset to rate base. Account 281 is not allocated. In compliance with FERC Rulemaking RM02-7-000, Asset Retirement Obligation deferrals have been removed from ratebase. Transmission ADIT allocations are shown on WS B.~~
~~The company will not include the ADIT portion of deferred hedge gains and losses in rate base.~~

~~E~~ ~~Cash Working Capital assigned to transmission is one-eighth of O&M allocated to transmission, as shown on line 253. It excludes:~~
~~1) Load Scheduling & Dispatch Charges in account 561 that are collected in the OATT Ancilliary Services Revenue, as shown on line 250.~~
~~2) AEP transmission equalization transfers, as shown on line 251~~
~~3) The impact of state regulatory deferrals and amortizations, as shown on line 252~~
~~4) All A&G Expenses, as shown on line 268.~~

~~F~~ ~~Consistent with Paragraph 657 of Order 2003-A, the amount on line 242 is equal to the balance of IPP System Upgrade Credits owed to transmission customers that made contributions toward the construction of System upgrades, and includes accrued interest and unreturned balance of contributions. The annual interest expense is included on line 300.~~

~~G~~ ~~Removes from the cost of service the Load Scheduling and Dispatch expenses booked to accounts 561.1 through 561.8. Expenses recorded in these accounts, with the exception of 561.4 & 561.8 (lines 180 & 181 above) are recovered in Schedule 1A, OATT ancillary services rates. See Worksheet F, lines 5 through 14, for descriptions and the Form 1 Source of these accounts' balances.~~

~~H~~ ~~Removes cost of transmission service provided by others to determine the basis of cash working capital on line 253. To the extent such service is incurred to provide the PJM service at issue, e.g. transmission equalization agreement, such costs are added back on lines 270 and 271 to determine the total O&M collected in the formula. The amounts on lines 270 and 271 are also excluded in the calculation of the FCR percentage calculated on lines 170 through 176. The addbacks on lines 270 and 271 of activity recorded in 565 represents inter-company sales or purchases of transmission capacity necessary to meet each AEP company's transmission load relative to their available transmission capacity. The company records referenced on lines 270 and 271 is the COMPANY NAME HERE general ledger.~~

~~I~~ ~~Removes the impact of state regulatory deferrals or their amortization from O&M expense.~~

J General Plant and Administrative & General expenses, other than in accounts 924, 928, and 930, will be functionalized based on the Wages & Salaries "W/S" allocator. The allocation basis for accounts 924, 928 and 930 are separately presented in the formula. A change in the allocation method for an account must be approved via a 205 filing with the FERC.

K These deductions on lines ~~256~~92 through ~~258~~94 are to remove from the cost of service the expenses recorded by the company for Postemployment Benefits Other than Pensions (PBOP). See Note M below for the recoverable PBOP expense.

L ~~Expenses reported for these A&G accounts will be included in the cost of service only to the extent they are directly assignable to transmission service. Worksheet F allocates these expense items. Acct 928 Includes Regulatory Commission expenses itemized in FERC Form-1 at page 351, column H. FERC Assessment Fees and Annual Charges shall not be allocated to transmission. Only safety-related and educational advertising costs in Account 930.1 are included in the TCOS.~~Expenses recorded in FERC Accounts 928 (Regulatory Commission Expense), 930.1 (Safety Related Advertising) and 930.2 (Miscellaneous General Expenses) that are not directly related to or properly allocable to transmission service will be removed from the TCOS. If AEP includes any expenses booked to these accounts in future ATRR updates, AEP must provide supporting information demonstrating that the underlying activities are directly related to providing transmission service. Account 930.2 includes the expenses incurred by the transmission function for Associated Business Development revenues given as a credit to the TCOS on Worksheet E.

M See note K above. Per the settlement in Docket ER08-1329, recoverable PBOP expense is based on an annual total for the operating companies that is ratioed to them based on the total of actual annual PBOP costs, including charges from the AEP Service ~~Corportation~~Corporation. The calculation of the recoverable amount for each company is shown on Worksheet O~~, and the process for updating the annual total is documented on Attachment F, Allowable PBOP Expense Formula~~.

N Includes only FICA, unemployment, highway, property and other assessments charged in the current year. Gross receipts, sales & use and taxes related to income are excluded.

O The currently effective income tax rate, where FIT is the Federal income tax rate; SIT is the State income tax rate, and p = the percentage of federal income tax deductible for state income taxes. See Worksheet G for the development of the Company's composite SIT.
A utility that elected to utilize amortization of tax credits against taxable income, rather than book tax credits to Account No. 255 and reduce rate base, must reduce its income tax expense by the amount of the Amortized Investment Tax Credit (Form 1, 266.8.f~~) expense by the amount of the Amortized Investment Tax Credit (Form 1, 266.8.f)~~).
~~expense by the amount of the Amortized Investment Tax Credit (Form 1, 266.8.f)~~
(ln ~~295~~131) multiplied by (1/1-T) . If the applicable tax rates are zero enter 0.

Inputs Required:	FIT =	0.00%	
	SIT=	0.00%	(State Income Tax Rate or Composite SIT. Worksheet G))
	p =	0.00%	(percent of federal income tax deductible for state purposes)

The formula rate shall reflect the applicable state and federal statutory tax rates in effect during the period the calculated estimated unit charges are applicable. If the statutory tax rates change during such period, the effective tax rates used in the formula shall be weighted by the number of days the pre-change rate and post-change rate each is in effect.

P Removes plant excluded from the OATT because it does not meet the PJM's definition of Transmission Facilities or is otherwise ineligible to be recovered under the OATT.

Q Removes transmission plant (e.g. step-up transformers) included in the development of OATT ancillary service rates and not already removed for reasons indicated in Note P.

R Includes functional wages & salaries billed by AEP Service Corporation for support of the operating company.

~~S~~ ~~Long Term Debt cost rate = long-term interest (ln 318) / long term debt (ln 327). Preferred Stock cost rate = preferred dividends (ln 319) / preferred outstanding (ln 328).~~
~~Common Stock cost rate (ROE) = 0%, the rate accepted by FERC in Docket No. ER08-1329. It includes an additional 50 basis points for remaining a member of the PJM RTO.~~

S ~~In the Projected & Historic templates, the interest expense on~~Long Term Debt cost rate = long-term interest (ln 158) /average long term debt ~~is the sum of a full year's interest expense at the coupon rate for each issuance~~(ln 167). Preferred Stock cost rate = preferred dividends (ln 159) / preferred outstanding ~~as of December 31 of the historic year. The projected expense for variable rate debt will be based on the effective~~(ln 168). Common Stock

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cost rate ~~at December 31. These conventions ensure that the expense used~~(ROE) = 11.49%, the rate accepted by FERC in ~~the projection will reflect a full year, similar to the actual expense that will appear in the subsequent true-up of the projection, and minimize the impact on the true-up of using a partial year interest expense. The projection will reflect the actual historic year expense recorded for issuance expenses, discounts and premiums, and gains or losses on reacquired debt. Eligible~~ Docket No. ER08-1329. It includes an additional 50 basis points for PJM RTO membership. The amount of eligible hedging gains or losses ~~will be~~included in total interest expense is limited to five basis points of the ~~projected~~ capital structure. Details and calculations of the weighted average cost of capital are shown on Worksheet ~~L.~~ M. Eligible Hedging Gains and Losses are computed on Worksheet M. The unamortized balance of eligible hedge gains/losses and related ADIT amounts shall not flow through the formula rate.

T The Long Term Debt balance for I&M includes the accumulated balance of principle and related interest for Spent Nuclear Fuel Disposal Costs collected prior to April 7, 1983. This total balance of _________ at 12/31/___ is not included in the balance in line ~~327 above.~~167 above. The cost rates for long-term debt shall include interest expense and related periodic expenses (such as remarketing and letter of credit fees) as recorded in FERC Account 427 or 430, amortization of issuance costs (including insurance) and discounts as recorded in FERC Account 428, issuance premiums as recorded in FERC Account 429 and losses or gains on reacquired debt as recorded in FERC Accounts 428.1 or 429.1, respectively. The cost rates for preferred stock (if applicable) shall include the dividends.

U Tax effect of permanent differences captures the differences in the income taxes due under the Federal and State calculations that are not the result of timing differences. Transmission balances for the projected or actual period, will be filed and posted as part of the informational filing.

V Cash investment in prepaid pension and benefits recorded in FERC Account 165 is permitted to be included in the formula. A labor expense allocation factor will be used to allocate total company costs. All other prepayments recorded in FERC Account 165 are directly assigned to the transmission function, allocated or excludable balances detailed on Worksheet C.

W The formula rate shall allocate property tax expense based on the as filed net plant cost allocation method detailed on Worksheet H.

~~U~~ X ~~This note only applies to the true-up template.~~ Under Section 30.9 of the PJM OATT, a network customer that owns existing transmission facilities that are integrated with the Transmission Provider's Transmission System may be eligible to receive consideration either through a billing credit or some other mechanism. Calculation of any credit under this subsection, pursuant to approval by FERC for inclusion in this formula rate for collection on behalf of the network customer, shall be addressed in either the Network Customer's Service Agreement or any other agreement between the parties.

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~~AEP East Companies~~
~~Transmission Cost of Service Formula Rate~~
~~Utilizing Actual Cost Data for Historic Year with Average Ratebase Balances~~
~~**COMPANY NAME HERE**~~

~~Line No.~~						~~Transmission Amount~~
~~1~~	~~REVENUE REQUIREMENT (w/o incentives)~~	~~(ln 138)~~				~~$0~~
			~~Total~~	~~Allocator~~		
~~2~~	~~REVENUE CREDITS~~	~~(Note A) (Worksheet E)~~	~~-~~	~~DA~~	~~1.00000~~	~~$ -~~
~~3~~	~~REVENUE REQUIREMENT For All Company Facilities~~	~~(ln 1 less ln 2)~~				~~$ -~~

~~**MEMO: The Carrying Charge Calculations on lines 6 to 11 below are used in calculating project revenue requirements billed through PJM Schedule 12, Transmission Enhancement Charges. The total non-incentive revenue requirements for these projects shown on line 4 is included in the total on line 3.**~~

~~4~~	~~Revenue Requirement for PJM Schedule 12 Facilities (w/o incentives) (Worksheet K)~~	~~-~~	~~DA~~	~~1.00000~~	~~$ -~~	
~~5~~	~~NET PLANT CARRYING CHARGE w/o intra-AEP charges or credits or ROE incentives (Note B)~~					
~~6~~	~~Annual Rate~~	~~((ln 1 - ln 105 - ln 106)/ ln 48 x 100)~~				~~0.00%~~
~~7~~	~~Monthly Rate~~	~~(ln 6 / 12)~~				~~0.00%~~
~~8~~	~~NET PLANT CARRYING CHARGE ON LINE 6 , w/o depreciation or ROE incentives (Note B)~~					
~~9~~	~~Annual Rate~~	~~((ln 1 - ln 105 - ln 106 - ln 111) / ln 48 x 100)~~				~~0.00%~~
~~10~~	~~NET PLANT CARRYING CHARGE ON LINE 9, w/o Return, income taxes or ROE incentives (Note B)~~					
~~11~~	~~Annual Rate~~	~~((ln 1 - ln 105 - ln 106 - ln 111 - ln 133 - ln 134) / ln 48 x 100)~~				~~0.00%~~
~~12~~	~~ADDITIONAL REVENUE REQUIREMENT for projects w/ incentive ROE's (Note B) (Worksheet K)~~	~~-~~				
~~13~~	~~**REVENUE REQUIREMENT FOR SCHEDULE 1A CHARGES**~~					
~~14~~	~~Total Load Dispatch & Scheduling (Account 561)~~	~~Line 85 Below~~				~~-~~
~~15~~	~~Less: Load Dispatch - Scheduling, System Control and Dispatch Services (321.88.b)~~					~~-~~
~~16~~	~~Less: Load Dispatch - Reliability, Planning & Standards Development Services (321.92.b)~~					
~~17~~	~~Total 561 Internally Developed Costs~~	~~(Line 14 - Line 15 - Line 16)~~				~~-~~

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AEP East Companies
Transmission Cost of Service Formula Rate
Utilizing Actual Cost Data for Historic Year with Average Ratebase Balances
COMPANY NAME HERE

Line No.	(1) RATE BASE CALCULATION	(2) Data Sources (See "General Notes")	(3) TO Total NOTE C	(4) Allocator		(5) Total Transmission
	GROSS PLANT IN SERVICE					
18	Production	(Worksheet A ln 1.E)	-	NA	0.00000	-
19	Less: Production ARO (Enter Negative)	(Worksheet A ln 2.E)	-	NA	0.00000	-
20	Transmission	(Worksheet A ln 3.E & Ln 142)	-	DA		-
21	Less: Transmission ARO (Enter Negative)	(Worksheet A ln 4.E & Ln 143)	-	TP	0.00000	-
22	Plus: Transmission Plant-in-Service Additions (Worksheet I)		N/A	NA	0.00000	N/A
23	Plus: Additional Trans Plant on Transferred Assets (Worksheet I)		N/A	NA	0.00000	N/A
24	Distribution	(Worksheet A ln 5.E)	-	NA	0.00000	-
25	Less: Distribution ARO (Enter Negative)	(Worksheet A ln 6.E)	-	NA	0.00000	-
26	General Plant	(Worksheet A ln 7.E)	-	W/S	0.00000	-
27	Less: General Plant ARO (Enter Negative)	(Worksheet A ln 8.E)	-	W/S	0.00000	-
28	Intangible Plant	(Worksheet A ln 9.E)	-	W/S	0.00000	-
29	TOTAL GROSS PLANT	(sum lns 18 to 28)	-	GP(h)=	0.00000	-
				GTD=	0.00000	
30	ACCUMULATED DEPRECIATION AND AMORTIZATION					
31	Production	(Worksheet A ln 12.E)	-	NA	0.00000	-
32	Less: Production ARO (Enter Negative)	(Worksheet A ln 13.E)	-	NA	0.00000	-
33	Transmission	(Worksheet A ln 14.E & 28.E)	-	TP1=	0.00000	-
34	Less: Transmission ARO (Enter Negative)	(Worksheet A ln 15.E)	-	TP1=	0.00000	-
35	Plus: Transmission Plant-in-Service Additions (Worksheet I)		N/A	DA	1.00000	N/A
36	Plus: Additional Projected Deprec on Transferred Assets (Worksheet I)		N/A	DA	1.00000	N/A
37	Plus: Additional Transmission Depreciation for Historic Year+1 (ln 111)		N/A	TP1	0.00000	N/A
38	Plus: Additional General & Intangible Depreciation for Historic Year+1 (ln 110 + ln 111)		N/A	W/S	0.00000	N/A
39	Plus: Additional Accum Deprec on Transferred Assets (Worksheet I)		N/A	DA	1.00000	N/A
40	Distribution	(Worksheet A ln 16.E)	-	NA	0.00000	-
41	Less: Distribution ARO (Enter Negative)	(Worksheet A ln 17.E)	-	NA	0.00000	-
42	General Plant	(Worksheet A ln 18.E)	-	W/S	0.00000	-
43	Less: General Plant ARO (Enter Negative)	(Worksheet A ln 19.E)	-	W/S	0.00000	-
44	Intangible Plant	(Worksheet A ln 20.E)	-	W/S	0.00000	-
45	TOTAL ACCUMULATED DEPRECIATION	(sum lns 31 to 44)	-			-
46	NET PLANT IN SERVICE					
47	Production	(ln 18 + ln 19 - ln 31 - ln 32)	-			-
48	Transmission	(ln 20 + ln 21 - ln 33 - ln 34)	-			-
49	Plus: Transmission Plant-in-Service Additions (ln 22 - ln 35)		N/A			N/A
50	Plus: Additional Trans Plant on Transferred Assets (ln 23 - ln 36)		N/A			N/A
51	Plus: Additional Transmission Depreciation for Historic Year+1 (-ln 37)		N/A			N/A
52	Plus: Additional General & Intangible Depreciation for Historic Year+1 (-ln 38)		N/A			N/A
53	Plus: Additional Accum Deprec on Transferred Assets (Worksheet I) (-ln 39)		N/A			N/A
54	Distribution	(ln 24 + ln 25 - ln 40 - ln 41)	-			-
55	General Plant	(ln 26 + ln 27 - ln 42 - ln 43)	-			-
56	Intangible Plant	(ln 28 - ln 44)	-			-
57	TOTAL NET PLANT IN SERVICE	(sum lns 47 to 56)	-	NP(h)=	0.00000	-
58	DEFERRED TAX ADJUSTMENTS TO RATE BASE	(Note D)				
59	Account No. 281.1 (enter negative)	(Worksheet B, ln 2 & ln 5.E)	-	NA		-
60	Account No. 282.1 (enter negative)	(Worksheet B, ln 7 & ln 10.E)	-	DA		-
61	Account No. 283.1 (enter negative)	(Worksheet B, ln 12 & ln 15.E)	-	DA		-
62	Account No. 190.1	(Worksheet B, ln 17 & ln 20.E)	-	DA		-
63	Account No. 255 (enter negative)	(Worksheet B, ln 24 & ln 25.E)	-	DA		-
64	TOTAL ADJUSTMENTS	(sum lns 59 to 63)	-			-
65	PLANT HELD FOR FUTURE USE	(Worksheet A ln 29.E & ln 30.E)	-	DA		-
66	REGULATORY ASSETS	(Worksheet A ln 36. (E))	-	DA		-
67	WORKING CAPITAL	(Note E)				
68	Cash Working Capital	(1/8 * ln 88)	-			-
69	Transmission Materials & Supplies	(Worksheet C, ln 2.F)	-	TP	0.00000	-
70	A&G Materials & Supplies	(Worksheet C, ln 3.F)	-	W/S	0.00000	-
71	Stores Expense	(Worksheet C, ln 4.(D))	-	GP(h)	0.00000	-
72	Prepayments (Account 165) - Labor Allocated	(Worksheet C, ln 8.G)	-	W/S	0.00000	-
73	Prepayments (Account 165) - Gross Plant	(Worksheet C, ln 8.F)	-	GP(h)	0.00000	-
74	Prepayments (Account 165) - Transmission Only	(Worksheet C, ln 8.E)	-	DA	1.00000	-
75	Prepayments (Account 165) - Unallocable	(Worksheet C, ln 8.D)	-	NA	0.00000	-
76	TOTAL WORKING CAPITAL	(sum lns 68 to 75)	-			-
77	IPP CONTRIBUTIONS FOR CONSTRUCTION	(Note F) (Worksheet D, ln 8 (B))	-	DA	1.00000	-
78	RATE BASE (sum lns 57, 64, 65, 66, 76, 77)		-			-

AEP East Companies
Transmission Cost of Service Formula Rate
Utilizing Actual Cost Data for Historic Year with Average Ratebase Balances
COMPANY NAME HERE

Line No.	(1) EXPENSE, TAXES, RETURN & REVENUE REQUIREMENTS CALCULATION	(2) Data Sources (See "General Notes")	TO Total	(3) Allocator	(4)	(5) Total Transmission
	OPERATION & MAINTENANCE EXPENSE					
79	Production	321.80.b	-			
80	Distribution	322.156.b	-			
81	Customer Related Expense	322.164,171,178.b	-			
82	Regional Marketing Expenses	322.131.b	-			
83	Transmission	321.112.b	-			
84	TOTAL O&M EXPENSES	(sum lns 79 to 83)	-			
85	Less: Total Account 561	(Note G) (Worksheet F, ln 14.C)	-			
86	Less: Account 565	(Note H) 321.96.b	-			
87	Less: Regulatory Deferrals & Amortizations	(Note I) (Worksheet F, ln 4.C)	-			
88	Total O&M Allocable to Transmission	(lns 83 - 85 - 86 - 87)	-	TP	0.00000	-
89	Administrative and General	323.197.b (Note J)	-			
90	Less: Acct. 924, Property Insurance	323.185.b	-			
91	Acct. 9260039 PBOP Expense	PBOP Worksheet O Line 9 & 10, (Note K)	-			
92	Acct. 9260057 PBOP Medicare Subsidy	PBOP Worksheet O Line 11, (Note K)	-			
93	PBOP Expense Billed From AEPSC	PBOP Worksheet O Line 13, (Note K)	-			
94	Acct. 928, Reg. Com. Exp.	323.189.b	-			
95	Acct. 930.1, Gen. Advert. Exp.	323.191.b	-			
96	Acct. 930.2, Misc. Gen. Exp.	323.192.b	-			
97	Balance of A & G	(ln 89 - sum ln 90 to ln 96)	-	W/S	0.00000	-
98	Plus: Acct. 924, Property Insurance	(ln 90)	-	GP(h)	0.00000	-
99	Acct. 928 - Transmission Specific	Worksheet F ln 20.(E) (Note L)	-	TP	0.00000	-
100	Acct 930.1 - Only safety related ads -Direct	Worksheet F ln 37.(E) (Note L)	-	TP	0.00000	-
101	Acct 930.2 - Misc Gen. Exp. - Trans	Worksheet F ln 43.(E) (Note L)	-	DA	1.00000	-
102	Settlement Approved PBOP Recovery	PBOP Worksheet O, Col. C, Line 1, (Note M)	-	W/S	0.00000	-
103	A & G Subtotal	(sum lns 97 to 102)	-			-
104	O & M EXPENSE SUBTOTAL	(ln 88 + ln 103)	-			-
105	Plus: TEA Settlement in Account 565	Company Records (Note H)	-	DA	1.00000	-
106	Plus: Transmission Lease Payments To Affiliates in Acct 565 (Company Records) (Note H)		-	DA	1.00000	-
107	TOTAL O & M EXPENSE	(ln 104 + ln 105 + ln 106)	-			-
108	DEPRECIATION AND AMORTIZATION EXPENSE					
109	Production	336.2-6.f	-	NA	0.00000	-
110	Distribution	336.8.f	-	NA	0.00000	-
111	Transmission	336.7.f	-	TP1	0.00000	-
112	Plus: Transmission Plant-in-Service Additions (Worksheet I)		N/A			N/A
113	General	336.10.f	-	W/S	0.00000	-
114	Intangible	336.1.f	-	W/S	0.00000	-
115	TOTAL DEPRECIATION AND AMORTIZATION	(Ln 109+110+111+112+113+114)	-			-
116	TAXES OTHER THAN INCOME	(Note N)				
117	Labor Related					
118	Payroll	Worksheet H ln 24.(D)	-	W/S	0.00000	-
119	Plant Related					
120	Property	Worksheet H ln 24.(C) & ln 59.(C)	-	DA		-
121	Gross Receipts/Sales & Use	Worksheet H ln 24.(F)	-	NA	0.00000	-
122	Other	Worksheet H ln 24.(E)	-	GP(h)	0.00000	-
123	TOTAL OTHER TAXES	(sum lns 118 to 122)	-			-
124	INCOME TAXES	(Note O)				
125	T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =		0.00%			
126	EIT=(T/(1-T)) * (1-(WCLTD/WACC)) =		0.00%			
127	where WCLTD=(ln 162) and WACC = (ln 165)					
128	and FIT, SIT & p are as given in Note O.					
129	GRCF=1 / (1 - T) = (from ln 125)		-			
130	Amortized Investment Tax Credit (enter negative)	(FF1 p.114, ln 19.c)	-			
131	Income Tax Calculation	(ln 126 * ln 134)	-			-
132	ITC adjustment	(ln 129 * ln 130)	-	NP(h)	0.00000	-
133	TOTAL INCOME TAXES	(sum lns 131 to 132)	-			-
134	RETURN ON RATE BASE (Rate Base*WACC)	(ln 78 * ln 165)	-			-
135	INTEREST ON IPP CONTRIBUTION FOR CONST. (Note F) (Worksheet D, ln 2.(B))		-	DA	1.00000	-
136	(Gains) / Losses on Sales of Plant Held for Future Use (Worksheet N, ln 4, Cols. ((F) & (H))		-			-
137	Tax Impact on Net Loss / (Gain) on Sales of Plant Held for Future Use (ln 136 * ln126)		-			-
138	TOTAL REVENUE REQUIREMENT		-			-
	(sum lns 107, 115, 123, 133, 134, 135)					

AEP East Companies
Transmission Cost of Service Formula Rate
Utilizing Actual Cost Data for Historic Year with Average Ratebase Balances
COMPANY NAME HERE
SUPPORTING CALCULATIONS

ln No.	TRANSMISSION PLANT INCLUDED IN PJM TARIFF								
139	Total transmission plant	(ln 20)							-
140	Less transmission plant excluded from PJM Tariff (Note P)								
141	Less transmission plant included in OATT Ancillary Services (Worksheet A, ln 23, Col. (C)) (Note Q)								-
142	Transmission plant included in PJM Tariff		(ln 139 - ln 140 - ln 141)						-
143	Percent of transmission plant in PJM Tariff		(ln 142 / ln 139)					**TP=**	**0.00000**

	WAGES & SALARY ALLOCATOR		Direct	Payroll Billed from AEP					
144	(W/S)	(Note R)	Payroll	Service Corp.	Total				
145	Production	354.20.b	0	0	-	NA	0.00000		-
146	Transmission	354.21.b	0	0	-	TP	0.00000		-
147	Regional Market Expenses	354.22.b	0	0	-	NA	0.00000		-
148	Distribution	354.23.b	0	0	-	NA	0.00000		-
149	Other (Excludes A&G)	354.24,25,26.b	0	0	-	NA	0.00000		-
150	Total	(sum lns 145 to 149)	0	0	0				-
151	Transmission related amount							**W/S=**	**0.00000**

152	WEIGHTED AVERAGE COST OF CAPITAL (WACC)		$
153	Long Term Interest	(Worksheet M, ln. 21, col. (E))	-
154	Preferred Dividends	(Worksheet M, ln. 56, col. (E))	-
155	Development of Common Stock:		Average
156	Proprietary Capital	(Worksheet M, ln. 1, col. (E))	-
157	Less: Preferred Stock	(Worksheet M, ln. 2, col. (E))	-
158	Less: Account 216.1	(Worksheet M, ln. 3, col. (E))	-
159	Less: Account 219	(Worksheet M, ln. 4, col. (E))	-
160	Common Stock	(ln 156 - ln 157 - ln 158 - ln 159)	-

			Capital Structure Weighting		Cost		
161		Average $	Actual	Cap Limit	(Note S)		Weighted
162	Long Term Debt (Note T) W/S M, ln 11, ln 22, col. (E))	-	0.00%	0.00%	-		0.0000
163	Preferred Stock (ln 157)	-	0.00%	0.00%	-		0.0000
164	Common Stock (ln 160)	-	0.00%	0.00%	0.00%		0.0000
165	Total (Sum lns 162 to 164)	-				**WACC=**	**0.0000**
166	Capital Structure Equity Limit (Note U)	-					

~~AEP East Companies~~

~~Transmission Cost of Service Formula Rate~~

~~Utilizing Actual Cost Data for Historic Year with Average Ratebase Balances~~

~~COMPANY NAME HERE~~

~~**Letter**~~	~~**Notes**~~
	~~General Notes: a) References to data from Worksheets are indicated as: Worksheet X, Line#.Column.X~~
	~~Revenue credits include:~~
	~~1) Forfeited Discounts.~~
	~~2) Miscellaneous Service Revenues.~~
	~~3) Rental revenues earned on assets included in the rate base.~~
	~~4) Revenues for associated business projects provided by employees whose labor and overhead costs are in the transmission cost of service.~~
	~~5) Other electric revenues.~~
	~~6) Revenues for grandfathered PTP contracts included in the load divisor.~~
~~A~~	~~See Worksheet E for details.~~
~~B~~	~~The annual and monthly net plant carrying charges on page 1 are used to compute the revenue requirement for RTEP sponsored upgrades or those projects receiving approved incentive ROE's.~~
~~C~~	~~Transmission Plant balances in this study reflect the average of the balances at December 31, Projected Year-2 and December 31, HistoricYear.~~
~~D~~	~~The total-company balances shown for Accounts 281, 282, 283, 190 only reflect ADIT that relates to utility operations. The balance of Account 255 is reduced by prior flow throughs and is completely excluded if the utility chose to utilize amortization of tax credits against FIT expense. An exception to this is pre-1971 ITC balances, which are required to be taken as an offset to rate base. Account 281 is not allocated. In compliance with FERC Rulemaking RM02-7-000, Asset Retirement Obligation deferrals have been removed from ratebase. Transmission ADIT allocations are shown on WS B.~~
	~~The company will not include the ADIT portion of deferred hedge gains and losses in rate base.~~
	~~Cash Working Capital assigned to transmission is one-eighth of O&M allocated to transmission, as shown on line 88. It excludes:~~
	~~1) Load Scheduling & Dispatch Charges in account 561 that are collected in the OATT Ancilliary Services Revenue, as shown on line 85.~~ ~~2) AEP transmission equalization transfers, as shown on line 86~~ ~~3) The impact of state regulatory deferrals and amortizations, as shown on line 87~~
~~E~~	~~4) All A&G Expenses, as shown on line 103.~~
~~F~~	~~Consistent with Paragraph 657 of Order 2003-A, the amount on line 77 is equal to the balance of IPP System Upgrade Credits owed to transmission customers that made contributions toward the construction of System upgrades, and includes accrued interest and unreturned balance of contributions. The annual interest expense is included on line 135.~~
~~G~~	~~Removes from the cost of service the Load Scheduling and Dispatch expenses booked to accounts 561.1 through 561.8. Expenses recorded in these accounts, with the exception of 561.4 & 561.8 (lines 15 & 16 above) are recovered in Schedule 1A, OATT ancillary services rates. See Worksheet F, lines 5 through 14, for descriptions and the Form 1 Source of these accounts' balances.~~
~~H~~	~~Removes cost of transmission service provided by others to determine the basis of cash working capital on line 88. To the extent such service is incurred to provide the PJM service at issue, e.g. transmission equalization agreement, such costs are added back on lines 105 and 106 to determine the total O&M collected in the formula. The amounts on lines 105 and 106 are also excluded in the calculation of the FCR percentage calculated on lines 5 through 11. The addbacks on lines 105 and 106 of activity recorded in 565 represents inter-company sales or purchases of transmission capacity necessary to meet each AEP company's transmission load relative to their available transmission capacity. The company records referenced on lines 105 and 106 is the COMPANY NAME HERE general ledger.~~
~~I~~	~~Removes the impact of state regulatory deferrals or their amortization from O&M expense.~~
~~J~~	~~General Plant and Administrative & General expenses, other than in accounts 924, 928, and 930, will be functionalized based on the Wages & Salaries "W/S" allocator. The allocation basis for accounts 924, 928 and 930 are separately presented in the formula. A change in the allocation method for an account must be approved via a 205 filing with the FERC.~~
~~K~~	~~These deductions on lines 91 through 93 are to remove from the cost of service the expenses recorded by the company for Postemployment Benefits Other than Pensions (PBOP). See Note M below for the recoverable PBOP expense.~~
~~L~~	~~Expenses reported for these A&G accounts will be included in the cost of service only to the extent they are directly assignable to transmission service. Worksheet F allocates these expense items. Acct 928 Includes Regulatory Commission expenses itemized in FERC Form 1 at page 351, column H. FERC Assessment Fees and Annual Charges shall not be allocated to transmission. Only safety-related and educational advertising costs in Account 930.1 are included in the TCOS. Account 930.2 includes the expenses incurred by the transmission function for Associated Business Development revenues given as a credit to the TCOS on Worksheet E.~~
~~M~~	~~See note K above. Per the settlement in Docket ER08-1329, recoverable PBOP expense is based on an annual total for the operating companies that is ratioed to them based on the total of actual annual PBOP costs, including charges from the AEP Service Corportation. The calculation of the recoverable amount for each company is shown on Worksheet O, and the process for updating the annual total is documented on Attachment F, Allowable PBOP Expense Formula.~~
~~N~~	~~Includes only FICA, unemployment, highway, property and other assessments charged in the current year. Gross receipts, sales & use and taxes related to income are excluded.~~
~~O~~	~~The currently effective income tax rate, where FIT is the Federal income tax rate; SIT is the State income tax rate, and p = the percentage of federal income tax deductible for state income taxes. See Worksheet G for the development of the Company's composite SIT. A utility that elected to utilize amortization of tax credits against taxable income, rather than book tax credits to Account No. 255 and reduce rate base, must reduce its income tax expense by the amount of the Amortized Investment Tax Credit (Form 1, 266.8.f) (ln 130) multiplied by (1/1-T) . If the applicable tax rates are zero enter 0.~~
	~~Inputs Required:~~ ~~FIT =~~ ~~0.00%~~ ~~SIT=~~ ~~0.00%~~ ~~(State Income Tax Rate or Composite SIT. Worksheet G))~~ ~~p =~~ ~~0.00%~~ ~~(percent of federal income tax deductible for state purposes)~~
~~P~~	~~Removes plant excluded from the OATT because it does not meet the PJM's definition of Transmission Facilities or is otherwise ineligible to be recovered under the OATT.~~
~~Q~~	~~Removes transmission plant (e.g. step-up transformers) included in the development of OATT ancillary service rates and not already removed for reasons indicated in Note P.~~
~~R~~	~~Includes functional wages & salaries billed by AEP Service Corporation for support of the operating company.~~
~~S~~	~~Long Term Debt cost rate = long-term interest (ln 153) /average long term debt (ln 162). Preferred Stock cost rate = preferred dividends (ln 154) / preferred outstanding (ln 163). Common Stock cost rate (ROE) = 0%, the rate accepted by FERC in Docket No. ER08-1329. It includes an additional 50 basis points for PJM RTO membership. Interest expense for the true-up WACC is based on actual expenses for the true-up year. The amount of eligible hedging gains or losses included in total interest expense is limited to five basis points of the true-up capital structure. Details and calculations of the true-up weighted average cost of capital are shown on Worksheet M. Eligible Hedging Gains and Losses are defined in the Formula Protocols in the tariff, and on Worksheet M.~~
~~T~~	~~The Long Term Debt balance for I&M includes the accumulated balance of principle and related interest for Spent Nuclear Fuel Disposal Costs collected prior to April 7, 1983.~~
	~~This total balance of _________ at 12/31/___ is not included in the balance in line 162 above.~~
~~U~~	~~Per Settlement, equity for COMPANY NAME HERE is limited to 0% of Capital Structure. If the percentage of equity exceeds the cap, the excess is included in weighted percentage of long term debt in the capital structure. During the period ended December 31, 2011 the equity cap is in effect. During this period, a change in the cap percentage must be approved via a 205 filing with the FERC.~~

AEP East Companies
Cost of Service Formula Rate Using ~~Historic Year~~Actual/Projected FF1 Balances

Worksheet A Supporting Plant Balances

COMPANY NAME HERE

Line Number	(A) Rate Base Item & Supporting Balance	Source of Data	(B) Balance @ December 31, ~~Historic~~Rate Year	(C) Balance @ December 31, ~~Historic~~Rate Year-1	(D) Average Balance for ~~Historic~~Rate Year	(E)
	NOTE: Functional ARO investment and accumulated depreciation balances shown below are included in the total functional balances shown here.					
	Plant Investment Balances					
1	**Production Plant In Service**	FF1, page 205 Col.(g) & pg. 204 Col. (b), ln 46			-	
2	**Production Asset Retirement Obligation (ARO)**	FF1, page 205&204, Col.(g)&(b), lns 15,24,34,44			-	
3	**Transmission Plant In Service**	FF1, page 207 Col.(g) & pg. 206 Col. (b), ln 58			-	
4	**Transmission Asset Retirement Obligation**	FF1, page 207 Col.(g) & pg. 206 Col. (b), ln 57			-	
5	**Distribution Plant In Service**	FF1, page 207 Col.(g) & pg. 206 Col. (b), ln 75			-	
6	**Distribution Asset Retirement Obligation**	FF1, page 207 Col.(g) & pg. 206 Col. (b), ln 74			-	
7	**General Plant In Service**	FF1, page 207 Col.(g) & pg. 206 Col. (b), ln 99			-	
8	**General Asset Retirement Obligation**	FF1, page 207 Col.(g) & pg. 206 Col. (b), ln 98			-	
9	**Intangible Plant In Service**	FF1, page 205 Col.(g) & pg. 204 Col. (b), ln 5			-	
10	**Total Property Investment Balance**	(Sum of Lines: 3, 1, 5, 7, 9)	-	-	-	
11	**Total ARO Balance (included in total on line 10)**	(Sum of Lines: 4, 2, 6, 8)	-	-	-	
	Accumulated Depreciation & Amortization Balances					
12	**Production Accumulated Depreciation**	FF1, page 219, lns 20-24, Col. (b)			-	
13	**Production ARO Accumulated Depreciation**	Company Records - Note 1			-	
14	**Transmission Accumulated Depreciation**	FF1, page 219, ln 25, Col. (b)			-	
15	**Transmission ARO Accumulated Depreciation**	Company Records - Note 1			-	
16	**Distribution Accumulated Depreciation**	FF1, page 219, ln 26, Col. (b)			-	
17	**Distribution ARO Accumulated Depreciation**	Company Records - Note 1			-	
18	**General Accumulated Depreciation**	FF1, page 219, ln 28, Col. (b)			-	
19	**General ARO Accumulated Depreciation**	Company Records - Note 1			-	
20	**Intangible Accumulated Amortization**	FF1, page 200, ln 21, Col. (b)			-	
21	**Total Accumulated Depreciation or Amortization**	(Sum of Lines: 14, 12, 16, 18, 20)	-	-	-	
22	**Total ARO Balance (included in total on line 21)**	(Sum of Lines: 15, 13, 17, 19)	-	-	-	
	Generation Step-Up Units					
23	**GSU Investment Amount**	Company Records - Note 1			-	
24	**GSU Accumulated Depreciation**	Company Records - Note 1			-	
25	**GSU Net Balance**	(Line 23 - Line 24)	-	-	-	
	Transmission Accumulated Depreciation Net of GSU Accumulated Depreciation					
26	**Transmission Accumulated Depreciation**	(Line 14 ~~1bove~~above)	-	-	-	
27	**Less: GSU Accumulated Depreciation**	(Line 24 ~~1bove~~above)	-	-	-	
28	**Subtotal of Transmission Net of GSU**	(Line 26 - Line 27)	-	-	-	
	Plant Held For Future Use					
29	**Plant Held For Future Use**	FF1, page 214, ln 47, Col. (d)			-	
30	**Transmission Plant Held For Future**	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.					
31					-	
32					-	
33					-	
34					-	
35					-	
36	Total Regulatory Deferrals Included in Ratebase		-	-	-	

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

NOTE: The ratebase should not include the unamoritzed balance of hedging gains or losses.

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AEP East Companies

Cost of Service Formula Rate Using ~~Historic Year~~Actual/Projected FF1 Balances

Worksheet B Supporting ADIT and ITC Balances

COMPANY NAME HERE

Line Number	(A) Description	(B) Source	(C) Balance @ December 31, ~~Historic~~Rate Year	(D) Balance @ December 31, ~~Historic~~Rate Year-1	(E) Average Balance for ~~Historic~~Rate Year
1	**Account 281**				
2	Year End Utility Deferrals	FF1, p. 272 - 273, ln 8, Col. (k)			-
3	Less: ARO Related Deferrals	Company Records - Note 1			-
4	Less: Other Excluded Deferrals	Company Records - 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	Company Records - Note 1			-
9	Less: Other Excluded Deferrals	Company Records - 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	Company Records - Note 1			-
14	Less: Other Excluded Deferrals	Company Records - 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	Company Records - Note 1			-
19	Less: Other Excluded Deferrals	Company Records - 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 Ratebase	Ln 22 - ln 23	-	-	-
25	Transmission Related Deferrals	Company Records - Note 1			-

NOTE 1 On this worksheet, "Company Records" refers to AEP's tax accounting ledger. Projected ending balances reflect proration required by IRS Letter Rule Section 1.167(I)-I(h)(6)(ii).

NOTE 2 ADIT balances should exclude balances related to hedging activity.

AEP East Companies
Cost of Service Formula Rate Using ~~Historic Year~~Actual/Projected FF1 Balances
Worksheet C Supporting Working Capital Rate Base Adjustments
COMPANY NAME HERE

Materials & Supplies

Line Number	(A)	(B)	(C) Source	(D) Balance @ December 31, ~~Historic~~Rate Year	(E)	(F) Balance @ December 31, ~~Historic~~Rate Year-1	(G)	(H) Average Balance for ~~Historic~~Rate Year	(I)
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)	FF1, p. 227, ln 16, Col. (c) & (b)			-			

Prepayment Balance Summary

Line Number		(C) Average of YE Balance	(D) Excludable Balances	(E) 100% Transmission Related	(F) Transmission Plant Related	(G) Transmission Labor Related	(H) Total Included in Ratebase (E)+(F)+(G)
5							
6	Totals as of December 31, ~~Historic~~Rate Year	0	0	0	0	0	0
7	Totals as of December 31, ~~Historic~~Rate Year-1						
8	**Average Balance**	-	-	-	-	-	-

Prepayments Account 165 - Balance @ 12/31/~~Historic~~Rate Year

Line	Acc. No.	Description	~~Historic~~Rate Year 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/ ~~Historic~~Rate Year-1

Line	Acc. No.	Description	~~Historic~~Rate Year-1 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						0		-	
25				0				-	
26				0				-	
27				0				-	
28				0				-	
29							0	-	
30				0				-	
31				0				-	
		Subtotal - Form 1, p 111.57.c							

AEP East Companies
Cost of Service Formula Rate Using ~~Historic Year~~Actual/Projected FF1 Balances
Worksheet D Supporting IPP Credits
COMPANY NAME HERE

Line Number	(A) Description	(B) ~~Historic~~Rate Year
1	Net Funds from IPP Customers 12/31/~~Historic~~Rate Year-1 (~~Historic~~Rate Year FORM 1, P269, line 24.b)	
2	Interest Accrual (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/~~Historic~~Rate Year (~~Historic~~Rate Year FORM 1, P269, line 24.f)	-
8	Average Balance for Year as Indicated in Column ((ln 1 + ln 7)/2)	-

~~Note 1~~
Note 1 On this worksheet Company Records refers to COMPANY NAME HERE's general ledger.

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AEP East Companies
Cost of Service Formula Rate Using ~~Historic Year~~Actual/Projected FF1 Balances
Worksheet E Supporting Revenue Credits
COMPANY NAME HERE

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 - Note 1)**		-	
5	**Account 456 - Other Electric Revenues - (Company Records - Note 1)**		-	
6	**Subtotal - Other Operating Revenues (Company Total equals (FF1 p. 300.26.(b))**	-	-	-
7	**Accounts 4470004 & ~~5~~4470005, Revenues from Grandfathered Transmission Contracts - (Company Records - Note 1)**		-	
8	**Total Other Operating Revenues To Reduce Revenue Requirement**	-	-	-

Note 1 The total company data on this worksheet comes from the indicated FF1 source, or COMPANY NAME HERE's general ledger. The functional amounts identified as transmission revenue also come from the general ledger.

9	**Facility Credits under PJM OATT Section 30.9**			

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AEP East Companies
Cost of Service Formula Rate Using ~~Historic Year~~Actual/Projected FF1 Balances
Worksheet F Supporting Allocation of Specific O&M or A&G Expenses
COMPANY NAME HERE

(A)		(B)	(C)	(D)	(E)	(F)
Line Number	Item No.	Description	~~Historic~~Rate Year 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	FF1 p 321.84.b	561 - Load Dispatching				
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**	0			
		Account 928				
15				-	-	
16				-	-	
17				-	-	
18				-	-	
19				-	-	
20		**Total**	-	-	-	
		Account 930.1				
21				-	-	
22				-	-	
23				-	-	
24				-	-	
25				-	-	
26				-	-	
27				-	-	
28				-	-	
29				-	-	
30				-	-	
31				-	-	
32				-	-	
33				-	-	
34				-	-	
35				-	-	
36				-	-	
37		**Total**	-	-	-	
		Account 930.2				
38			0			
39			0			
40			0			
41			0			
42			0			
43		**Total**	-	-	-	

AEP East Companies

Cost of Service Formula Rate Using ~~Historic Year~~Actual/Projected FF1 Balances

Worksheet G Supporting - Development of Composite State Income Tax Rate

COMPANY NAME HERE

State #1 Tax Rate		
Apportionment Factor - Note ~~2~~1		
Effective State Tax Rate		0.00%
State #2 Tax Rate		
Apportionment Factor - Note ~~2~~1		
Effective State Tax Rate		0.00%
State #3 Tax Rate		
Apportionment Factor - Note ~~2~~1		
Effective State Tax Rate		0.00%
State #4 Tax Rate		
Apportionment Factor - Note ~~2~~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.~~The Ohio State Income Tax is being phased-out pro rata over a 5 year period from 2005 through 2009. The taxable portion of income is 20% in 2009. The phase-out factors can be found in the Ohio Revised Code at 5733.01(G)2(a)(v). This tax has been replaced with a Commercial Activities Tax that is included in Schedule H and H-1.~~

~~Note 2~~ ~~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 ~~Historic Year~~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		Production	Transmsission	Distribution	General	Total
25	Functionalized Net Plant (~~Hist.~~ TCOS, Lns ~~212~~48 thru ~~222~~58)	-	-	-	-	-
	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)	-	-	-	-	-
~~33a~~	~~Ohio Company Merger Mitigation adjustment (Note 2)~~	~~31,000,000~~	~~(31,000,000)~~			~~-~~
34	Weighted STATE JURISDICTION #1 Plant (Ln 31 + 33 ~~+ 33a~~)	~~31,000,000~~ -	~~(31,000,000)~~ -	-	-	-
35	Functional Percentage (Ln 34/Total Ln 34)	0.00%	0.00%	0.00%		
36	Functionalized Expense in STATE JURISDICTION #1	-	-	-		-
	STATE JURISDICTION #2					
37	Percentage of Plant in STATE JURISDICTION #2					
38	Net Plant in STATE JURISDICTION #2 (Ln 25 * Ln 37)	-	-	-	-	-
39	Less: Net Value of Exempted Generation Plant					
40	Taxable Property Basis (Ln 38 - Ln 39)	-	-	-	-	-
41	Relative Valuation Factor					
42	Weighted Net Plant (Ln 40 * Ln 41)	-	-	-	-	
43	General Plant Allocator (Ln 42 / (Total - General Plant))	0.00%	0.00%	0.00%	-100.00%	
44	Functionalized General Plant (Ln 43 * General Plant)	-	-	-	-	-
45	Weighted STATE JURISDICTION #2 Plant (Ln 42 + 44)	-	-	-	-	-
46	Functional Percentage (Ln 45/Total Ln 45)	0.00%	0.00%	0.00%		
47	Functionalized Expense in STATE JURISDICTION #2	-	-	-		-
	STATE JURISDICTION #3					
48	Net Plant in STATE JURISDICTION #3 (Ln 25 - Ln 27 - Ln 38)	-	-	-	-	-
49	Less: Net Value Exempted Generation Plant					
50	Taxable Property Basis	-	-	-	-	-
51	Relative Valuation Factor					
52	Weighted Net Plant (Ln 50 * Ln 51)	-	-	-	-	
53	General Plant Allocator (Ln 52 / (Total - General Plant)	0.00%	0.00%	0.00%	-100.00%	
54	Functionalized General Plant (Ln 54 * General Plant)	-	-	-	-	
55	Weighted STATE JURISDICTION #3 Plant (Ln 52 + 54)	-	-	-	-	-
56	Functional Percentage (Ln 55/Total Ln 55)	0.00%	0.00%	0.00%		
57	Functionalized Expense in STATE JURISDICTION #3	-	-	-		-
58	Total Other Jurisdictions: (Line 7 * Net Plant Allocator)		-			-
59	Total Func. Property Taxes (Sum Lns 36, 47 57, 58)	-	-	-		-

~~Note 2: This adjustment will apply to AEP Ohio only. This adjustment will be in effect for the Annual Updates prepared in 2012, 2013, 2014, 2015 and 2016.~~

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	-		
3	**Real Estate and Personal Property Taxes**			
4	Real and Personal Property - Jurisdiction 1	-		
5	Real and Personal Property - Other Jurisdictions	-		
6	**Payroll Taxes**			
7	Federal Insurance Contribution (FICA)	-		
8	Federal Unemployment Tax	-		
9	State Unemployment Insurance	-		
10	Payroll Taxes	-	-	
11	**Production Taxes**			
12	Production Tax 1	-		
13	**Miscellaneous Taxes**			
14	Miscellaneous Tax 1	-		
15	Miscellaneous Tax 2	-		
16	Miscellaneous Tax 3	-		
17	Miscellaneous Tax 4	-		
18	Miscellaneous Tax 5	-		
19	Miscellaneous Tax 6	-		
20	Miscellaneous Tax 7	-		
21	Miscellaneous Tax 8	-		
22	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.

AEP East Companies

Cost of Service Formula Rate Using ~~Historic Year~~Actual/Projected FF1 Balances

Worksheet I ~~Supporting Transmission Plant in Service Additions~~

~~(A)~~RESERVED FOR FUTURE USE	~~(B)~~	~~(C)~~	~~(D)~~	~~(E)~~	~~(F)~~			~~(G)~~	~~(H)~~	~~(I)~~
~~I.~~	~~Calculation of Composite Depreciation Rate~~									
~~1~~		~~Transmission Plant @ Beginning of Historic Period (Historic Year) (P.206, ln 58,(b)):~~	~~-~~							
~~2~~		~~Transmission Plant @ End of Historic Period (Historic Year) (P.207, ln 58,(g)):~~								
~~3~~								~~-~~		
~~4~~		~~Average Balance of Transmission Investment~~			~~-~~					
~~5~~		~~Annual Depreciation Expense, Historic TCOS, ln 276~~								
~~6~~		~~Composite Depreciation Rate~~				~~0.00%~~				
~~7~~		~~Round to 0% to Reflect a Composite Life of 0 Years~~		~~0.00%~~						
~~II.~~	~~Calculation of Property Placed in Service by Month and the Related Depreciation Expense~~									
~~8~~		~~Month in Service~~	~~Capitalized Balance~~	~~Composite Annual Depreciation Rate~~	~~Annual Depreciation~~	~~Monthly Depreciation~~	~~No. Months Depreciation~~	~~First Year Depreciation Expense~~		
~~9~~		~~January~~	~~-~~	~~0.00%~~	~~$ -~~	~~$ -~~	~~11~~	~~$ -~~		
~~10~~		~~February~~	~~-~~	~~0.00%~~	~~$ -~~	~~$ -~~	~~10~~	~~$ -~~		
~~11~~		~~March~~	~~-~~	~~0.00%~~	~~$ -~~	~~$ -~~	~~9~~	~~$ -~~		
~~12~~		~~April~~	~~-~~	~~0.00%~~	~~$ -~~	~~$ -~~	~~8~~	~~$ -~~		
~~13~~		~~May~~	~~-~~	~~0.00%~~	~~$ -~~	~~$ -~~	~~7~~	~~$ -~~		
~~14~~		~~June~~	~~-~~	~~0.00%~~	~~$ -~~	~~$ -~~	~~6~~	~~$ -~~		
~~15~~		~~July~~	~~-~~	~~0.00%~~	~~$ -~~	~~$ -~~	~~5~~	~~$ -~~		
~~16~~		~~August~~	~~-~~	~~0.00%~~	~~$ -~~	~~$ -~~	~~4~~	~~$ -~~		
~~17~~		~~September~~	~~-~~	~~0.00%~~	~~$ -~~	~~$ -~~	~~3~~	~~$ -~~		
~~18~~		~~October~~	~~-~~	~~0.00%~~	~~$ -~~	~~$ -~~	~~2~~	~~$ -~~		
~~19~~		~~November~~	~~-~~	~~0.00%~~	~~$ -~~	~~$ -~~	~~1~~	~~$ -~~		
~~20~~		~~December~~	~~-~~	~~0.00%~~	~~$ -~~	~~$ -~~	~~0~~	~~$ -~~		
~~21~~		~~Investment~~	~~$ -~~				~~Depreciation Expense~~	~~$ -~~		
~~III.~~	~~Plant Transferred~~									
~~22~~			~~-~~	~~<== This input area is for original cost plant~~						
~~23~~			~~-~~	~~<== This input area is for accumulated depreciation that may be associated with capital expenditures. It would have an impact if a company had assets transferred from a subsidiary.~~						
~~24~~	~~(Ln 7 * Ln 22)~~	~~$~~	~~<== This input area is for additional~~							

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~~Depreciation Expense~~

~~IV.~~	~~**List of Major Projects Expected to be In-Service in 2009**~~			
			~~**Estimated Cost (000's)**~~	~~**Month in Service**~~
~~25~~	~~**Major Zonal Projects**~~			
~~26~~				
~~30~~			~~-~~	
~~31~~		~~Subtotal~~	~~-~~	
~~32~~	~~**PJM Socialized/Beneficiary Allocated Regional Projects**~~			
~~33~~			~~-~~	
~~34~~		~~Subtotal~~	~~-~~	

AEP East Companies
Cost of Service Formula Rate Using ~~Historic Year~~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 (~~Projected~~ TCOS, ln ~~164~~169)				0.00%	
Project ROE Incentive Adder					~~<==ROE Adder Cannot Exceed 125 Basis Points~~
ROE with additional basis point incentive				0.00%	~~<== ROE Including Incentives Cannot Exceed 12.74% Until July 1, 2012~~

Determine R (cost of long term debt, cost of preferred stock and equity percentage is from the ~~Projected~~ TCOS, lns ~~162 through164~~167 through169)

	%	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 (~~Projected~~ TCOS, ln ~~78~~79)	-	
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 (~~Projected~~ TCOS, ln ~~126~~127)		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 (~~Projected~~ TCOS, ln 1)	-		
~~T.E.A. &~~ Lease Payments (~~Projected~~ TCOS, ~~Lns 105 & 106~~107)	-		
Return (~~Projected~~ TCOS, ln ~~134~~139)		-	
Income Taxes (~~Projected~~ TCOS, ln ~~133~~138)	-		
Annual Revenue Requirement, Less ~~TEA Charges~~Lease Payments, Return and Taxes		-	

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

Annual Revenue Requirement, Less ~~TEA Charges~~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 (~~Projected~~ TCOS, ln ~~111~~112)	-	
Annual Rev. Req, w/ Basis Point ROE increase, less Depreciation	-	

C. Determine FCR with hypothetical basis point ROE increase.

Net Transmission Plant (~~Projected~~ TCOS, ln ~~48~~49)	-	
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 (~~Projected~~ TCOS, ln ~~9~~10)		0.00%
Incremental FCR with Basis Point ROE increase, less Depreciation		0.00%

III Calculation of Composite Depreciation Rate

Transmission Plant @ Beginning of ~~Historic Period (Historic~~Rate Year~~)~~ (P.206, ln 58,(b)):	-	
Transmission Plant @ End of ~~Historic Period (Historic~~Rate Year~~)~~ (P.207, ln 58,(g)):	-	
Subtotal	-	
Average Transmission Plant Balance for ~~Historic~~Rate Year	-	
Annual Depreciation ~~Rate (Projected~~ and Amortization Expense (TCOS, ln ~~111~~112)	-	
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 ~~Historic Year~~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 (~~True-Up~~ TCOS, ln ~~164~~169)	0.00%	
Project ROE Incentive Adder		~~<==ROE Adder Cannot Exceed 100 Basis Points~~
ROE with additional basis point incentive	0.00%	**~~<== ROE Including Incentives Cannot Exceed 12.5% Until July 1, 2012~~**

Determine R (cost of long term debt, cost of preferred stock and equity percentage is from the ~~True-Up~~ TCOS, lns ~~162 through164~~167 through169)

	%	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 (~~True-Up~~ TCOS, ln ~~78~~79)	-	
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 (~~True-Up~~ TCOS, ln ~~126~~127)		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 (~~True-Up~~ TCOS, ln 1)	-	
~~T.E.A. &~~ Lease Payments (~~True-Up~~ TCOS, ~~Lns 105 & 106~~Ln 107)	-	
Return (~~True-Up~~ TCOS, ln ~~134~~139)		-
Income Taxes (~~True-Up~~ TCOS, ln ~~133~~138)	-	
Annual Revenue Requirement, Less ~~TEA Charges~~Lease Payments, Return and Taxes		-

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

Annual Revenue Requirement, Less ~~TEA Charges~~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 (~~True-Up~~ TCOS, ln ~~111~~112)	-
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 (~~True-Up~~ TCOS, ln ~~48~~49)		
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 (~~True-Up~~ TCOS, ln ~~9~~10)		0.00%
Incremental FCR with Basis Point ROE increase, less Depreciation		0.00%

III. Calculation of Composite Depreciation Rate

Transmission Plant @ Beginning of ~~Historic Period ()~~Rate Year (P.206, ln 58,(b)):	-
Transmission Plant @ End of ~~Historic Period ()~~Rate Year (P.207, ln 58,(g)):	-
Subtotal	-

Average Transmission Plant Balance for	-	
Annual Depreciation ~~Rate (True-Up~~ and Amortization Expense (TCOS, ln ~~111~~112)	-	
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 ~~True-Up~~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.

<u>TRUE UP OF PROJECT REVENUE REQUIREMENT FOR PRIOR YEAR:</u>

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

AEP East Companies
Cost of Service Formula Rate Using ~~Historic Year~~Actual/Projected FF1 Balances
Worksheet L ~~Supporting Projected Cost of Debt~~
COMPANY NAME HERE

~~Calculation of Projected Interest Expense Based on Outstanding Debt at Year End~~ RESERVED FOR FUTURE USE

~~Line Number~~	~~(A)~~ ~~Issuance~~	~~(B)~~ ~~Principle Outstanding~~	~~(C)~~ ~~Interest Rate~~	~~(D)~~ ~~Annual Expense (See Note S on Projected Template)~~	~~(E)~~ ~~Notes~~
~~1~~	~~Long Term Debt (FF1.p. 256-257.h)~~				
~~2~~	-	-	-		
~~3~~	-	-	-	-	
~~4~~	~~Installment Purchase Contracts (FF1.p. 256-257.h, a)~~				
~~5~~	-	-	-		
~~6~~	-	-	-		
~~7~~	-	-	-		
~~8~~	-	-	-		
~~9~~	-	-	-		
~~10~~	-	-	-		
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~~21~~	-	-	-		
~~22~~	-	-	-		
~~23~~	-	-	-		
~~24~~	-	-	-		
~~25~~	-	-	-		
~~26~~	~~Sale/Leaseback~~	-	~~0.000%~~	-	
~~27~~	~~Issuance Discount, Premium, & Expenses:~~				
~~28~~	~~Auction Fees~~	~~FF1.p. 256 & 257.Lines Described as Fees~~		-	
~~29~~	~~Allowable Hedge Amortization (See Ln 45 Below)~~				
~~30~~	~~Amort of Debt Discount and Expenses~~	~~FF1.p. 117.63.c~~		-	
~~31~~	~~Amort of Debt Premimums (Enter Negative)~~	~~FF1.p. 117.65.c~~		-	
~~32~~	~~Reacquired Debt:~~				
~~33~~	~~Amortization of Loss~~	~~FF1.p. 117.64.c~~		-	
~~34~~	~~Amortization of Gain~~	~~FF1.p. 117.66.c~~		-	
~~35~~	~~Total Interest on Long Term Debt~~	-	~~0.00%~~		
~~36~~	~~Preferred Stock (FF1.p. 250-251)~~	~~Preferred Shares Outstanding~~			
~~37~~	-	-	-		
~~38~~	-	-	-		
~~39~~	-	-	-		
~~40~~	~~Dividends on Preferred Stock~~	-	~~0.00%~~		
~~41~~	~~Eligible Hedging Gains and Losses (WS M, Ln 35, (E))~~				
~~42~~	~~Total Projected Capital Structure Balance for Historic Year+1 (Projected TCOS, Ln 165)~~				
~~43~~	~~Financial Hedge Recovery Limit – Five Basis Points of Total Capital~~			~~0.0005~~	
~~44~~	~~Limit of Recoverable Amount~~				
~~45~~	~~Recoverable Hedge Amortization (Lesser of Ln 41 or Ln 44)~~				

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AEP East Companies
Transmission Cost of Service Formula Rate Using Actual/Projected FF1 Balances
COMPANY NAME HERE
Worksheet M Supporting Calculation of Capital Structure and Weighted Average Cost of Capital Based on Average of Balances At 12/31/~~Historic~~Rate Year-1 & 12/31/~~Historic~~Rate Year

(A) Line	**(B)**	**(C)** Balances @ 12/31/~~Historic~~Rate Year	**(D)** Balances @ 12/31/~~Historic~~Rate Year-1	**(E)** Average
Development of Average Balance of Common Equity				
1	Proprietary Capital (112.16.c&d)			-
2	Less Preferred Stock (Ln 55 Below)	0	-	-
3	Less Account 216.1 (112.12.c&d)			0
4	Less Account 219.1 (112.15.c&d)			0
5	**Average Balance of Common Equity**	-	-	-
Development of Cost of Long Term Debt Based on Average Outstanding Balance				
6	Bonds (112.18.c&d)			0
7	Less: Reacquired Bonds (112.19.c&d)			0
8	LT Advances from Assoc. Companies (112.20.c&d)			-
9	Senior Unsecured Notes (112.21.c&d)			0
10	Less: Fair Value Hedges (See Note on Ln 12 below)			0
11	**Total Average Debt**	-	-	-
12	**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. (Column H of the FF1)**			
13	**Annual Interest Expense for ~~Historic~~Rate Year**			
14	Interest on Long Term Debt (256-257.33.i)			
15	Less: Total Hedge Gain/Expense Accumulated from p 256-257, col. (i) of FERC Form 1 included in Ln 14 and shown in Ln 34 below.			
16	Plus: Allowed Hedge Recovery From Ln 39 below.			-
17	Amort of Debt Discount & Expense (117.63.c)			
18	Amort of Loss on Reacquired Debt (117.64.c)			
19	Less: Amort of Premium on Debt (117.65.c)			
20	Less: Amort of Gain on Reacquired Debt (117.66.c)			
21	**Total Interest Expense (Ln 14 + Ln 17 + Ln 18 - Ln 19 - Ln 20)**			-
22	**Average Cost of Debt for ~~Historic~~Rate Year (Ln 21/Ln 11)**			**0.00%**

CALCULATION OF RECOVERABLE HEDGE GAINS/LOSSES

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

	HEDGE AMOUNTS BY ISSUANCE (FROM p. 256-257 (i) of the FERC Form 1)	**Total Hedge (Gain)/Loss for ~~Historic~~Rate Year**	**Less Excludable Amounts (See NOTE on Line 23)**	**Net Includable Hedge Amount**	**Remaining Unamortized Balance**	**Amortization Period** Beginning	Ending
24	Senior Unsecured Notes			-			
25	Senior Unsecured Notes			-			
26	Senior Unsecured Notes			-			
27	Senior Unsecured Notes			-			
28	Senior Unsecured Notes			-			
29	Senior Unsecured Notes			-			
30	Senior Unsecured Notes			-			
31	Senior Unsecured Notes			-			
32	Senior Unsecured Notes			-			
33	Senior Unsecured Notes			-			
34	Total Hedge Amortization	-	-				

35	Hedge Gain or Loss Prior to Application of Recovery Limit (Sum of Lines 24 to 33)	-
36	Total Average Capital Structure Balance for ~~Historic~~Rate Year (~~True-UP~~ TCOS, Ln ~~165~~170)	-
37	Financial Hedge Recovery Limit - Five Basis Points of Total Capital	0.0005
38	Limit of Recoverable Amount	-
39	**Recoverable Hedge Amortization (Lesser of Ln 35 or Ln 38)**	-

Development of Cost of Preferred Stock

	Preferred Stock			**Average**
40	0% Series - - Dividend Rate (p. 250-251. 7 & 10.a)			
41	0% Series - - Par Value (p. 250-251. 8.c)			
42	0% Series - - Shares O/S (p.250-251. 8 & 11.e)			
43	0% Series - - Monetary Value (Ln 41 * Ln 42)	-	-	-
44	0% Series - - Dividend Amount (Ln 40 * Ln 43)	-	-	-
45	0% Series - - Dividend Rate (p. 250-251.a)			
46	0% Series - - Par Value (p. 250-251.c)			
47	0% Series - - Shares O/S (p.250-251. e)			
48	0% Series - - Monetary Value (Ln 46 * Ln 47)	-	-	-
49	0% Series - - Dividend Amount (Ln 45 * Ln 48)	-	-	-
50	0% Series - - Dividend Rate (p. 250-251.a)			
51	0% Series - - Par Value (p. 250-251.c)			
52	0% Series - - Shares O/S (p.250-251.e)			
53	0% Series - - Monetary Value (Ln 51 * Ln 52)	-	-	-
54	0% Series - - Dividend Amount (Ln 50 * Ln 53)	-	-	-
55	**Balance of Preferred Stock (Lns 43, 48, 53)**	-	-	- Year End Total Agrees to FF1 p.112, Ln 3, col (c) & (d)
56	**Dividends on Preferred Stock (Lns 44, 49, 54)**	-	-	-
57	**Average Cost of Preferred Stock (Ln 56/55)**	0.00%	0.00%	**0.00%**

AEP East Companies

Cost of Service Formula Rate Using ~~Historic Year~~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 ~~Historic~~Rate Year		-		-	

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AEP East Companies
Cost of Service Formula Rate Using ~~Historic Year~~*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 ~~Historic~~*Rate* *Year*:

Line #	Company	Actual Expense (Including AEPSC Billed OPEB) (A) (Line 14)	Ratio of Company Actual to Total (B)=(A)/Total (A)	Allocation of PBOB Recovery Allowance (C)=(B) * 1	Labor Allocator for ~~Historic~~*Rate* Year (D)	Actual Expense (E)=(A) * (D)	Allowable Expense (F)=(C) * (D)	One Year Functional Expense (Over)/Under (G)=(E) - (F)
~~1~~2	APCo	-	0.00%	-		-	-	-
~~2~~								
3	I&M		0.00%	-		-	-	-
4	KPCo		0.00%	-		-	-	-
5	KNGP		0.00%	-		-	-	-
6	OPCo		0.00%	-		-	-	-
7	WPCo		0.00%	-		-	-	-
8	**Sum of Lines 1 to 8**	-		-		-	-	-

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

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

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Note: PBOP Expense will be calculated in accordance with the settlement in Docket ER08-1329.

~~14~~ 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.~~Company PBOP Expense (Ln 12 + Ln 13)~~

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AEP EAST COMPANIES

Worksheet - P CALCULATION OF

TOTAL WEIGHTED AVERAGE DEPRECIATION RATES

FOR TRANSMISSION PLANT PROPERTY ACCOUNT

EFFECTIVE AS OF 6/1/2015

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				6.67%	1.000000	6.67%							6.67%
Structures & Improvements	352.0	1.55%	0.469583	0.73%	1.52%	0.437847	0.67%	2.19%	0.036426	0.08%	2.19%	0.056144	0.12%	1.60%
Station Equipment	353.0	1.95%	0.4695834	0. 92%	1.68%	0.437847	0.74%	2.19%	0.036426	0.08%	2.19%	0.056144	0.12%	1.86%
Towers & Fixtures	354.0	1.14%	0.469583	0.54%	1.54%	0.437847	0.67%	2.19%	0.036426	0.08%	2.19%	0.056144	0.12%	1.41%
Poles & Fixtures	355.0	2.77%	0.4695834	1.30%	2.64%	0.437847	1.16%	2.19%	0.036426	0.08%	2.19%	0.056144	0.12%	2.66%
Overhead Conductor	356.0	1.01%	0.4695834	0.47%	1.19%	0.437847	0.52%	2.19%	0.036426	0.08%	2.19%	0.056144	0.12%	1.19%
Underground Conduit	357.0	1.23%	0.469583	0.58%	1.45%	0.437847	0.63%	2.19%	0.036426	0.08%	2.19%	0.056144	0.12%	1.41%
Underground Conductors	358.0	3.18%	0.469583	1.49%	7.23%	0.437847	3.17%	2.19%	0.036426	0.08%	2.19%	0.056144	0.12%	4.86%

(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 May 26, 2015in

Case No. 14-1151-E-D effective June 1, 2015.

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

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

(5) ~~2009 Allocation factors based on APCo's 12 monthly Coincident Peaks for twelve months ended September 30, 2008 as provided by AEPSC Regulated Pricing.~~ 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.

~~Per the terms of the settlement in this case,~~ 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 July 1, 2014

FOR MULTIPLE JURISDICTION COMPANIES

INDIANA MICHIGAN POWER COMPANY

	INDIANA				**MICHIGAN**			**FERC WHOLESALE**			**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	1.27%	.646552	.8211%	1.1700%	.139381	.1631%	1.1700%	.214067	.2505%	1.23%
Structures & Improvements	352.0	1.32%	.646552	.8534%	1.2700%	.139381	.1770%	1.2700%	.214067	.2719%	1.30%
Station Equipment	353.0	1.69%	.646552	1.0927%	1.6500%	.139381	.2300%	1.6500%	.214067	.3532%	1.68%
Towers & Fixtures	354.0	1.60%	.646552	1.0345%	1.4400%	.139381	.2007%	1.4400%	.214067	.3083%	1.54%
Poles & Fixtures	355.0	2.43%	.646552	1.5711%	2.3900%	.139381	.3331%	2.3900%	.214067	.5116%	2.42%
Overhead Conductors	356.0	1.53%	.646552	.9892%	1.4500%	.139381	.2021%	1.4500%	.214067	.3104%	1.50%
Underground Conduit	357.0	1.56%	.646552	1.0086%	1.3900%	.139381	.1937%	1.3900%	.214067	.2976%	1.50%
Underground Conductors	358.0	1.55%	.646552	1.0022%	1.4600%	.139381	.2035%	1.4600%	.214067	.3125%	1.52%
Trails & Roads	359.0	1.49%	.646552	.9634%	1.4700%	.139381	.2049%	1.4700%	.214067	.3147%	1.48%

(1) As approved in Indiana Case No.44075.

(2) As approved in Michigan Case No. U16801.

(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.

<u>GENERAL NOTES:</u>

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.

~~Per the terms of the settlement in this case,~~ 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.

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AEP EAST COMPANIES
PJM FORMULA RATE
WORKSHEET P - TRANSMISSION DEPRECIATION RATES
EFFECTIVE AS OF ~~9/~~1/~~1/2009~~2016
FOR SINGLE JURISDICTION COMPANIES

KINGSPORT POWER COMPANY

	PLANT ACCT.	RATES Note 1
TRANSMISSION PLANT		
Structures & Improvements	352.0	~~2.10~~1.04%
Station Equipment	353.0	~~2.57~~1.49%
Towers & Fixtures	354.0	~~1.91~~0.12%
Poles & Fixtures	355.0	~~4.20~~2.14%
Overhead Conductors	356.0	~~2.50~~0.77%
Underground Conduit	357.0	Note 2
Underground Conductors	358.0	Note 2
Composite Transmission Depreciation Rate		**~~2.59~~1.46%**

Reference:

Note 1: Rates Approved In Tennessee Regulatory Authority ~~Case~~Docket No. ~~U-84-7308~~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
~~Per the terms of the settlement in this case,~~ 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.

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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%

Reference:

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

General Note:

~~Per the terms of the settlement in this case,~~ 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		
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%

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.

General Note:

~~Per the terms of the settlement in this case,~~ 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 6/1/2015

FOR SINGLE JURISDICTION COMPANIES

WHEELING POWER COMPANY

	PLANT ACCT.	RATES Note 1
TRANSMISSION PLANT		
Structures & Improvements	352.0	0.69%
Station Equipment	353.0	1.70%
Towers & Fixtures	354.0	0.04%
Poles & Fixtures	355.0	2.65%
Overhead Conductors	356.0	1.12%
Underground Conduit	357.0	2.00%
Underground Conductors	358.0	5.00%
Trails & Roads	359.0	-

Note 1: Rates Approved in WV Public Service Commission Case No. 14-1151-E-D.

General Note:

~~Per the terms of the settlement in this case,~~ 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.

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Attachment E

A schedule setting forth prior and revised depreciation expense for KgPCo

KINGSPORT POWER COMPANY
SCHEDULE II - COMPARE DEPRECIATION EXPENSE USING CURRENT AND STUDY RATES
ANNUAL DEPRECIATION RATES AND ACCRUALS BY THE REMAINNG LIFE METHOD
BASED ON PLANT IN SERVICE AT DECEMBER 31, 2014

ACCT. NO. (1)	ACCOUNT TITLE (2)	ORIGINAL COST (3)	CURRENT APPROVED RATE (4)	ANNUAL ACCRUAL (5)	STUDY RATE (6)	STUDY ACCRUAL (7)	DIFFERENCE (DECREASE) (8)
TRANSMISSION PLANT							
352	Structures & Improvements	621,014	2.59%	16,084	1.04%	6,455	(9,629)
353	Station Equipment	22,147,754	2.59%	573,627	1.49%	330,414	(243,213)
354	Towers & Fixtures	765,475	2.59%	19,826	0.12%	904	(18,922)
355	Poles & Fixtures	2,839,237	2.59%	73,536	2.14%	60,850	(12,686)
356	OH Conductor & Devices	2,163,051	2.59%	56,023	0.77%	16,701	(39,322)
	Total Transmission Plant	**28,536,531**	**2.59%**	**739,096**	**1.46%**	**415,324**	**(323,772)**

Note: A depreciation study has not been prepared for Kingsport Power Company since 1983. The data used to prepare that study is not readily available and it is the recommendation of this study to use the mortality curve, average service life and net salvage information selected for APCo. Both Companies have similar operating conditions and the use of APCo data provides a robust source of retirements, removal cost and salvage.