AMERICAN ELECTRIC POWER

American Electric Power
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Columbus, OH 43215
AEP.com

March 3, 2014

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. ER14-1408-000

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 ("I&M"), Kentucky Power Company, Kingsport Power Company, Ohio Power Company, and Wheeling Power Company, (collectively referred to herein as "AEP East Operating Companies"), and on behalf of its subsidiaries AEP Appalachian Transmission Company Inc., AEP Indiana Michigan Transmission Company Inc., AEP Kentucky Transmission Company Inc., AEP Ohio Transmission Company Inc., and AEP West Virginia Transmission Company Inc. (collectively the "AEP East Transmission Companies") (AEPSC, the AEP East Operating Companies, and the AEP East Transmission Companies are collectively referred to herein as "AEP") submits for filing updated depreciation rates for I&M, AEP Indiana Michigan Transmission Company Inc. and AEP Ohio Transmission Company Inc. approved by the Indiana Utility Regulatory Commission ("IURC"), which will be reflected in the formula rate of the AEP Operating Companies, Attachment H-14 of the PJM Interconnection, L.L.C. ("PJM") Open Access Transmission Tariff ("PJM Tariff") and in the formula rate of the AEP East Transmission Companies, Attachment H-20A of the PJM Tariff.

I. Background

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 ("Attachment H-14 Settlement") was approved by the Commission on October 1, 2010.[2]

Attachment H-14 contains a formula rate for transmission service over the facilities of the AEP East Operating Companies, which is updated annually. As explained in the Attachment H-14 Formula Rate Implementation Protocols, the depreciation rates are "stated values to be used in the rate formula until changed pursuant to an FPA Section 205 or 206 filing."[3] Those stated values are found in Attachment H-14B, Worksheet P. Appendix A to Attachment H-14 (Cost of Service and Formula Rate Settlement Principles) further provides that "AEP will make a Section 205 filing at FERC . . . to reflect in the formula rate calculations any change in state commission-approved or FERC- approved depreciation rates."

In Docket No. ER10-355, AEP submitted for filing a formula rate and implementation protocols under Attachment H-20 of the PJM Tariff. AEP and the intervening parties in Docket No. ER10-355 ultimately settled all issues raised with respect to the formula rate, and the settlement ("Attachment H-20 Settlement") was approved by the Commission on April 21, 2011.[4]

Attachment H-20A contains a formula rate for transmission service over the facilities of the AEP East Transmission Companies, which is updated annually. As explained in Appendix A to Attachment H-20A Formula Rate Settlement Principles, "The AEP Transmission Companies will record depreciation expense using composites of the depreciation rates attached as Appendix A.1.2, which rates will not be changed absent an Order of the Commission approving such change in a Section 205 or 206 filing at FERC to seek a change in depreciation rates." As stated in the settlement, "the Settling Parties have agreed that the formula rate would use AEP's composite depreciation rates which are based on state commission-approved and FERC-approved depreciation rates."

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

2 *See American Electric Power Service Corp.*, 133 FERC ¶ 61,007 (2010). On March 14, 2012, in Docket No. ER12-1255 AEP filed amendments to Attachment H-14 to reflect an internal corporate reorganization under which Columbus Southern Power Company merged into Ohio Power Company. The Commission accepted the amendments by letter order. *See PJM Interconnection, L.L.C. and American Electric Power Service Corp.*, Docket No. ER12-1255, Letter Order (May 3, 2012).

3 Attachment H-14 Formula Rate Implementation Protocols, Section 1(g)(i).

4 *See AEP Appalachian Transmission Company, Inc.*, 135 FERC ¶ 61,066 (2011).

II. Description of Proposed Changes

The depreciation rates for I&M that generate the book expense included in the formula rate calculation approved as part of the Attachment H-14 Settlement were set in 2007. As a result of a recent retail rate case before the IURC (Cause No. 44075), the I&M depreciation rates included in the Attachment H-14 formula rate calculation are now outdated. The Depreciation Study Report and IURC order approving the underlying depreciation rates can be viewed at the following links:

Depreciation Study Report (Exhibit I&M-61):
http://efile.mpsc.state.mi.us/efile/docs/16801/0004.pdf

IURC Final Order in Cause No. 44075:
https://myweb.in.gov/IURC/eds/Modules/Ecms/Cases/Docketed_Cases/ViewDocument.aspx?DocID=0900b6318019959c

Consistent with the principles of the Attachment H-14 Settlement, AEP seeks Commission authorization to update the depreciation rate inputs in its existing formula rate to reflect the new state-approved depreciation rates for I&M. The updated depreciation rates are set forth in Attachment A to this transmittal letter and reflected in a revised Worksheet - P – "Calculation of Total Weighted Average Depreciation Rates for Transmission Plant Property Account Effective as of 4/1/2012 for Multiple Jurisdiction Companies Indiana Michigan Power Company." The changes in depreciation rates will result in increased annual transmission depreciation expenses for I&M. The depreciation rates for Transmission plant increased due to increases in the net salvage ratio for eight accounts (accounts 350, 352, 353, 354, 355, 356, 357 and 358). The annualized effect of the change in depreciation rates can be seen in the summaries of prior and new depreciation rates contained in Attachment A, pages 1 through 3.

As previously noted, the formula rate for the AEP East Transmission Companies utilizes AEP's composite depreciation rates, which are based on state commission-approved and FERC-approved depreciation rates. Consequently, any updates to the depreciation rates for the AEP East Operating Companies trigger corresponding updates to the AEP East Transmission Companies. Therefore, AEP also proposes updated depreciation rates for the AEP East Transmission Companies, which are based on the new state-approved depreciation rates for I&M. These new depreciation rates are set forth in Attachment D to this transmittal letter and reflected in a revised Worksheet P – Depreciation Rates for Transmission Plant Property Accounts Effective as of 7/1/2010 for AEP Indiana Michigan Transmission Company and AEP Ohio Transmission Company.

On February 26, 2014, in Docket No. ER14-1375, AEP filed a revision to Attachment H-14 to update the base Post-employment Benefits Other than Pensions ("PBOP") expense. This revision is pending with FERC and the changes are italicized in the tariff.[5]

III. Effective Date

AEP seeks approval to update the data inputs regarding depreciation rates in its formula rate to reflect the new state approved depreciation rates effective as of July 1, 2014. While the depreciation rates were approved by the IURC and went into effect March 1, 2013, customers will not see any impact until rates go into effect on July 1, 2014, pending FERC approval.

While implementation of AEP's request will result in an overall depreciation rate and expense increase, AEP notes that the inclusion of accurate depreciation rates based on state and FERC approvals was an agreed-upon aspect of both the Attachment H-14 and Attachment H-20 Settlements. Therefore, the request in this filing relates to the implementation of the formula rates as originally approved and is not a change to the design of the formula rates themselves. AEP further clarifies that it is not seeking a change in the manner in which the composite depreciation rate is calculated.

IV. Contents of this Filing

This filing consists of the following documents:

a. This transmittal letter;
b. A spreadsheet setting forth prior and revised state approved depreciation rates and twelve months ending October 31, 2013 for I&M annualized depreciation expense for AEP East Companies (Attachment A, Pages 1-3);
c. Revised Attachment H-14B, Worksheet P tariff sheet in clean form (Attachment B);
d. Revised Attachment H-14B, Worksheet P tariff sheet in redlined form (Attachment C);
e. A spreadsheet setting forth prior and revised state approved depreciation rates and twelve months ending October 31, 2013 annualized depreciation expense for AEP East Transmission Companies (Attachment D, Pages 1-6);
f. Revised Attachment H-20A, Appendix A.1.2 tariff sheet in clean form (Attachment E); and
g. Revised Attachment H-20A, Appendix A.1.2 tariff sheet in redlined form (Attachment F).

Pursuant to Section 35.7 of the Commission's regulations,[6] the contents of this filing are being submitted as part of an XML filing package that conforms to the Commission's eTariff instructions.

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[5] That filing involved three proposed changes to Worksheet O, including the updating of references to the year 2008 to refer to "Historic Year".

V. Service

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,[7] 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[8] alerting them that this filing has been made by PJM and is available by following such link. PJM also serves the parties listed on the Commission's official service list for this docket. 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/

VI. Correspondence

Correspondence relating to this filing should be addressed to:

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6 Pursuant to Order No. 714, this filing is submitted by PJM Interconnection, L.L.C. ("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 Attachment H-14B and H-20A in the eTariff system as part of PJM's electronic Intra PJM Tariff.

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

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

VII. Conclusion

Wherefore, AEP respectfully requests that the Commission accept these revised tariff sheets, effective July 1, 2014 for the AEP East Operating Companies and the AEP East Transmission Companies, and grant any applicable waivers.

Respectfully submitted,

/s/ Amanda R. Conner

Amanda R. Conner
Senior Counsel
American Electric Power Service Corporation

Attachment A

Spreadsheet setting forth
prior and revised state approved depreciation rates,
and twelve months annualized depreciation expense

AEP EAST COMPANIES
Worksheet - P CALCULATION OF
TOTAL WEIGHTED AVERAGE DEPRECIATION RATES
FOR TRANSMISSION PLANT PROPERTY ACCOUNT
EFFECTIVE AS OF July 1, 2014 [CURRENT RATES]
FOR MULTIPLE JURISDICTION COMPANIES
INDIANA MICHIGAN POWER COMPANY

		INDIANA			**MICHIGAN**			**FERC WHOLESALE**			**COMPANY**
	PLANT ACCT.	*(1) IURC RATES*	*ALLOCATION FACTOR (4)*	*WTD AVG. DEPREC. RATE*	*(2) MPSC APPROVED RATES (A)*	*ALLOCATION FACTOR (4)*	*WTD AVG. DEPREC. RATE*	*(3) FERC RATES (A)*	*ALLOCATION FACTOR (4)*	*WTD AVG. DEPREC. RATE*	*WTD AVG. DEPREC. RATE*
TRANSMISSION PLANT											
Land Improvements	350.1	1.2700%	0.646552	0.8211%	1.1700%	0.139381	0.1631%	1.1700%	0.214067	0.2505%	1.23%
Structures & Improvements	352.0	1.3200%	0.646552	0.8534%	1.2700%	0.139381	0.1770%	1.2700%	0.214067	0.2719%	1.30%
Station Equipment	353.0	1.6900%	0.646552	1.0927%	1.6500%	0.139381	0.2300%	1.6500%	0.214067	0.3532%	1.68%
Towers & Fixtures	354.0	1.6000%	0.646552	1.0345%	1.4400%	0.139381	0.2007%	1.4400%	0.214067	0.3083%	1.54%
Poles & Fixtures	355.0	2.4300%	0.646552	1.5711%	2.3900%	0.139381	0.3331%	2.3900%	0.214067	0.5116%	2.42%
Overhead Conductors	356.0	1.5300%	0.646552	0.9892%	1.4500%	0.139381	0.2021%	1.4500%	0.214067	0.3104%	1.50%
Underground Conduit	357.0	1.5600%	0.646552	1.0086%	1.3900%	0.139381	0.1937%	1.3900%	0.214067	0.2976%	1.50%
Underground Conductors	358.0	1.5500%	0.646552	1.0022%	1.4600%	0.139381	0.2035%	1.4600%	0.214067	0.3125%	1.52%
Trails & Roads	359.0	1.4900%	0.646552	0.9634%	1.4700%	0.139381	0.2049%	1.4700%	0.214067	0.3147%	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.
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 4/1/2012 [Prior RATES]
FOR MULTIPLE JURISDICTION COMPANIES
INDIANA MICHIGAN POWER COMPANY

		INDIANA			**MICHIGAN**			**FERC WHOLESALE**			**COMPANY**
	PLANT ACCT.	*(1) IURC RATES*	*ALLOCATION FACTOR (4)*	*WTD AVG. DEPREC. RATE*	*(2) MPSC APPROVED RATES (B)*	*ALLOCATION FACTOR (4)*	*WTD AVG. DEPREC. RATE*	*(3) FERC RATES (B)*	*ALLOCATION FACTOR (4)*	*WTD AVG. DEPREC. RATE*	*WTD AVG. DEPREC. RATE*
TRANSMISSION PLANT											
Land Improvements	350.1	1.1600%	0.654549	0.7593%	1.1700%	0.152798	0.1788%	1.1700%	0.192653	0.2254%	1.16%
Structures & Improvements	352.0	1.1500%	0.654549	0.7527%	1.2700%	0.152798	0.1941%	1.2700%	0.192653	0.2447%	1.19%
Station Equipment	353.0	1.4600%	0.654549	0.9556%	1.6500%	0.152798	0.2521%	1.6500%	0.192653	0.3179%	1.53%
Towers & Fixtures	354.0	1.4600%	0.654549	0.9556%	1.4400%	0.152798	0.2200%	1.4400%	0.192653	0.2774%	1.45%
Poles & Fixtures	355.0	2.1900%	0.654549	1.4335%	2.3900%	0.152798	0.3652%	2.3900%	0.192653	0.4604%	2.26%
Overhead Conductors	356.0	1.2300%	0.654549	0.8051%	1.4500%	0.152798	0.2216%	1.4500%	0.192653	0.2793%	1.31%
Underground Conduit	357.0	1.4500%	0.654549	0.9491%	1.3900%	0.152798	0.2124%	1.3900%	0.192653	0.2678%	1.43%
Underground Conductors	358.0	1.3500%	0.654549	0.8836%	1.4600%	0.152798	0.2231%	1.4600%	0.192653	0.2813%	1.39%
Trails & Roads	359.0	1.5000%	0.654549	0.9818%	1.4700%	0.152798	0.2246%	1.4700%	0.192653	0.2832%	1.49%

(1) As approved in Indiana Case No. 43231.
(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.
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.

INDIANA MICHIGAN POWER COMPANY
Worksheet - P CALCULATION OF
ANNUALIZED DEPRECIATION EXPENSE
FOR TRANSMISSION PLANT PROPERTY ACCOUNT
Using Current and Prior Depreciation Rates by Account and Plant Balance
Twelve Months Ended October 31, 2013

		Original Cost 10/31/2013	Current Rates (A)	Current Annual Dep Expense	Prior Rates (B)	Prior Annual Dep Expense
TRANSMISSION PLANT						
Land Improvements	350.1	54,455,536.94	1.23%	669,803.10	1.16%	631,684.23
Structures & Improvements	352.0	21,064,892.16	1.30%	273,843.60	1.19%	250,672.22
Station Equipment	353.0	634,558,862.47	1.68%	10,660,588.89	1.53%	9,708,750.60
Towers & Fixtures	354.0	231,322,477.50	1.54%	3,562,366.15	1.45%	3,354,175.92
Poles & Fixtures	355.0	113,467,501.04	2.42%	2,745,913.53	2.26%	2,564,365.52
Overhead Conductors	356.0	239,905,357.03	1.50%	3,598,580.36	1.31%	3,142,760.18
Underground Conduit	357.0	2,326,334.40	1.50%	34,895.02	1.43%	33,266.58
Underground Conductors	358.0	6,063,381.25	1.52%	92,163.40	1.39%	84,281.00
Trails & Roads	359.0	349,749.76	1.48%	5,176.30	1.49%	5,211.27
		1,303,514,092.55		21,643,330.33		19,775,167.52

Attachment B

Revisions to Section(s) of the
PJM Open Access Transmission Tariff

(Clean Format)

AEP East Companies
Cost of Service Formula Rate Using Historic Year FF1 Balances
Worksheet G Supporting - Development of Composite State Income Tax Rate
COMPANY NAME HERE

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

Note 1 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 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.

Functional Property Tax Allocation

Line		Production	Transmsission	Distribution	General	Total
25	Functionalized Net Plant (Hist. TCOS, Lns 212 thru 222)	-	-	-	-	-
	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

	(A)	(B)	(C)	(D)
Line No.	Annual Tax Expenses by Type (Note 1)	Total Company	FERC FORM 1 Tie-Back	FERC FORM 1 Reference
1	**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 FF1 Balances

Worksheet I Supporting Transmission Plant in Service Additions

(A)	(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 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 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)	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)

	%	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)	-	
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)		0.00%
Income Tax Calculation (Return x CIT)	-	
ITC Adjustment	-	
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)	-	
Return (Projected TCOS, ln 134)		-
Income Taxes (Projected TCOS, ln 133)	-	
Annual Revenue Requirement, Less TEA Charges, Return and Taxes		-

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

Annual Revenue Requirement, Less TEA Charges, 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)	-
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)	-	
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)		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 Year) (P.206, ln 58,(b)):	-
Transmission Plant @ End of Historic Period (Historic Year) (P.207, ln 58,(g)):	-

Subtotal	-	
Average Transmission Plant Balance for Historic Year	-	
Annual Depreciation Rate (Projected TCOS, ln 111)	-	
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		-		-	-	-

<u>CUMULATIVE HISTORY OF PROJECTED ANNUAL REVENUE REQUIREMENTS:</u>

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 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)	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)

	%	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)	-	
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)		0.00%
Income Tax Calculation (Return x CIT)	-	
ITC Adjustment	-	
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)	-	
Return (True-Up TCOS, ln 134)		-
Income Taxes (True-Up TCOS, ln 133)	-	
Annual Revenue Requirement, Less TEA Charges, Return and Taxes		-

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

Annual Revenue Requirement, Less TEA Charges, 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)	-
Annual Rev. Req, w/ Basis Point ROE increase, less Depreciation	-

SUMMARY OF TRUED-UP ANNUAL REVENUE REQUIREMENTS FOR RTEP PROJECTS

TRUE-UP YEAR		Rev Require	W Incentives	Incentive Amounts
	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)		
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)		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 () (P.206, ln 58,(b)):	-
Transmission Plant @ End of Historic Period () (P.207, ln 58,(g)):	-
Subtotal	-
Average Transmission Plant Balance for	-
Annual Depreciation Rate (True-Up TCOS, ln 111)	-

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	-	-	-
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		-			-	-	-

TRUE UP OF PROJECT REVENUE REQUIREMENT FOR PRIOR YEAR:
CUMULATIVE HISTORY OF TRUED-UP ANNUAL REVENUE REQUIREMENTS:

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

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

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

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.

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

Calculation of Projected Interest Expense Based on Outstanding Debt at Year End

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				-	
11				-	
12				-	
13				-	
14				-	
15				-	
16				-	
17				-	
18				-	
19				-	
20				-	
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)**			**-**	

AEP East Companies
Transmission Cost of Service Formula Rate
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 Year-1 & 12/31/Historic Year

(A) Line	(B)	(C) Balances @ 12/31/Historic Year	(D) Balances @ 12/31/Historic 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 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 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 Historic 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 Historic Year (True-UP TCOS, Ln 165)	-
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)**	-

Line	***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 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 Year		-		-	

AEP East Companies

Cost of Service Formula Rate Using *Historic Year* FF1 Balances

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

COMPANY NAME HERE

Total AEP East Operating Company PBOP Settlement Amount

Allocation of PBOP Settlement Amount for *Historic 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 *Historic Year***	**Actual Expense**	**Allowable Expense**	**One Year Functional Expense (Over)/Under**
		(A) (Line 14)	**(B)=(A)/Total (A)**	**(C)=(B) ***	**(D)**	**(E)=(A) * (D)**	**(F)=(C) * (D)**	**(G)=(E) - (F)**
1	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

		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)	-	-	-	-	-	-	

AEP EAST COMPANIES

Worksheet - P CALCULATION OF

TOTAL WEIGHTED AVERAGE DEPRECIATION RATES

FOR TRANSMISSION PLANT PROPERTY ACCOUNT

EFFECTIVE AS OF 1/1/2009

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%
Structures & Improvements	352.0	1.55%	0.461344	0.72%	1.55%	0.451517	0.70%	2.19%	0.029810	0.07%	2.19%	0.057329	0.13%	1.61%
Station Equipment	353.0	1.95%	0.461344	0. 90%	1.95%	0.451517	0.88%	2.19%	0.029810	0.07%	2.19%	0.057329	0.13%	1.97%
Towers & Fixtures	354.0	1.14%	0.461344	0.53%	1.14%	0.451517	0.51%	2.19%	0.029810	0.07%	2.19%	0.057329	0.13%	1.23%
Poles & Fixtures	355.0	2.77%	0.461344	1.28%	2.77%	0.451517	1.25%	2.19%	0.029810	0.07%	2.19%	0.057329	0.13%	2.72%
Overhead Conductor	356.0	1.01%	0.461344	0.47%	1.01%	0.451517	0.46%	2.19%	0.029810	0.07%	2.19%	0.057329	0.13%	1.12%
Underground Conduit	357.0	1.23%	0.461344	0.57%	1.24%	0.451517	0.56%	2.19%	0.029810	0.07%	2.19%	0.057329	0.13%	1.32%
Underground Conductors	358.0	3.18%	0.461344	1.47%	3.18%	0.451517	1.44%	2.19%	0.029810	0.07%	2.19%	0.057329	0.13%	3.10%

(1) As approved in VA Case No. PUE 2006-00065 on May 15, 2007.
Depreciation rates were made effective on January 1, 2006.

(2) Approved by PSC of WV Order dated July 26, 2006 in
Case No. 05-1278-E-PC-PW-42T effective July 1, 2006.

(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.

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.

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.

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 1/1/2009

FOR SINGLE JURISDICTION COMPANIES

KINGSPORT POWER COMPANY

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

Reference:

Note 1: Rates Approved In Tennessee Regulatory Authority Case No. U-84-7308.

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.

AEP EAST COMPANIES

PJM FORMULA RATE

WORKSHEET P - TRANSMISSION DEPRECIATION RATES

EFFECTIVE AS OF 1/1/2009

FOR SINGLE JURISDICTION COMPANIES

KENTUCKY POWER COMPANY

	PLANT ACCT.	RATES Note 1
TRANSMISSION PLANT		
Structures & Improvements	352.0	1.71%
Station Equipment	353.0	1.71%
Towers & Fixtures	354.0	1.71%
Poles & Fixtures	355.0	1.71%
Overhead Conductors	356.0	1.71%
Underground Conduit	357.0	1.71%
Underground Conductors	358.0	1.71%
Trails & Roads	359.0	1.71%

Reference:

Note 1: Rates Approved in Kentucky Public Service Commission Case No. 91-066.

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 1/1/2009

FOR SINGLE JURISDICTION COMPANIES

WHEELING POWER COMPANY

	PLANT ACCT.	RATES Note 1
TRANSMISSION PLANT		
Structures & Improvements	352.0	2.70%
Station Equipment	353.0	2.70%
Towers & Fixtures	354.0	2.70%
Poles & Fixtures	355.0	2.70%
Overhead Conductors	356.0	2.70%
Underground Conduit	357.0	2.70%
Underground Conductors	358.0	2.70%
Trails & Roads	359.0	2.70%

Note 1: Rates Approved in WV Public Service Commission Case No. PSC 90-243-E-42T.

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.

Attachment C

Revisions to Section(s) of the
PJM Open Access Transmission Tariff

(Marked / Redline Format)

AEP East Companies
Cost of Service Formula Rate Using Historic Year FF1 Balances
Worksheet G Supporting - Development of Composite State Income Tax Rate
COMPANY NAME HERE

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

Note 1 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 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.

Functional Property Tax Allocation

Line No.		Production	Transmsission	Distribution	General	Total
25	Functionalized Net Plant (Hist. TCOS, Lns 212 thru 222)	-	-	-	-	-
	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 FF1 Balances

Worksheet I Supporting Transmission Plant in Service Additions

(A)	(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

		Month in Service	Capitalized Balance	Composite Annual Depreciation Rate	Annual Depreciation	Monthly Depreciation	No. Months Depreciation	First Year Depreciation Expense
8								
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 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 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)	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)

	%	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)	-	
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)		0.00%
Income Tax Calculation (Return x CIT)	-	
ITC Adjustment	-	
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)	-	
Return (Projected TCOS, ln 134)		-
Income Taxes (Projected TCOS, ln 133)	-	
Annual Revenue Requirement, Less TEA Charges, Return and Taxes		-

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

Annual Revenue Requirement, Less TEA Charges, 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)	-
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)	-	
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)		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 Year) (P.206, ln 58,(b)):	-
Transmission Plant @ End of Historic Period (Historic Year) (P.207, ln 58,(g)):	-

Subtotal	-	
Average Transmission Plant Balance for Historic Year	-	
Annual Depreciation Rate (Projected TCOS, ln 111)	-	
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 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)	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)

	%	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)	-	
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)		0.00%
Income Tax Calculation (Return x CIT)	-	
ITC Adjustment	-	
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)	-	
Return (True-Up TCOS, ln 134)		-
Income Taxes (True-Up TCOS, ln 133)	-	
Annual Revenue Requirement, Less TEA Charges, Return and Taxes		-

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

Annual Revenue Requirement, Less TEA Charges, 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)	-
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)		
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)		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 () (P.206, ln 58,(b)):	-
Transmission Plant @ End of Historic Period () (P.207, ln 58,(g)):	-
Subtotal	-
Average Transmission Plant Balance for	-
Annual Depreciation Rate (True-Up TCOS, ln 111)	-

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	-	-	-
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		-			-	-	-

TRUE UP OF PROJECT REVENUE REQUIREMENT FOR PRIOR YEAR:

CUMULATIVE HISTORY OF TRUED-UP ANNUAL REVENUE REQUIREMENTS:

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

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

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

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.

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

Calculation of Projected Interest Expense Based on Outstanding Debt at Year End

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				-	
11				-	
12				-	
13				-	
14				-	
15				-	
16				-	
17				-	
18				-	
19				-	
20				-	
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)**			**-**	

AEP East Companies
Transmission Cost of Service Formula Rate
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 Year-1 & 12/31/Historic Year

(A) Line	(B)	(C) Balances @ 12/31/Historic Year	(D) Balances @ 12/31/Historic 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 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 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 Historic 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 Historic Year (True-UP TCOS, Ln 165)			-			
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 Historic Year 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 Year		-		-	

AEP East Companies
Cost of Service Formula Rate Using *Historic Year* FF1 Balances
Worksheet O - Calculation of Postemployment Benefits Other than Pensions Expenses Allocable to Transmission Service
COMPANY NAME HERE

Total AEP East Operating Company PBOP Settlement Amount

Allocation of PBOP Settlement Amount for *Historic 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 *Historic Year*	Actual Expense	Allowable Expense	One Year Functional Expense (Over)/Under
		(A) (Line 14)	(B)=(A)/Total (A)	(C)=(B) *	(D)	(E)=(A) * (D)	(F)=(C) * (D)	(G)=(E) - (F)
1	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

		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)	-	-	-	-	-	-	

AEP EAST COMPANIES

Worksheet - P CALCULATION OF

TOTAL WEIGHTED AVERAGE DEPRECIATION RATES

FOR TRANSMISSION PLANT PROPERTY ACCOUNT

EFFECTIVE AS OF 1/1/2009

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*	*WTD AVG. ALLOCATION FACTOR (5)*	*DEPREC. RATE*	*WTD AVG. DEPREC. RATE*
TRANSMISSION PLANT														
Land Rights - Va.	350.1	0.66%	1.000000	0.66%										0.66%
Structures & Improvements	352.0	1.55%	0.461344	0.72%	1.55%	0.451517	0.70%	2.19%	0.029810	0.07%	2.19%	0.057329	0.13%	1.61%
Station Equipment	353.0	1.95%	0.461344	0. 90%	1.95%	0.451517	0.88%	2.19%	0.029810	0.07%	2.19%	0.057329	0.13%	1.97%
Towers & Fixtures	354.0	1.14%	0.461344	0.53%	1.14%	0.451517	0.51%	2.19%	0.029810	0.07%	2.19%	0.057329	0.13%	1.23%
Poles & Fixtures	355.0	2.77%	0.461344	1.28%	2.77%	0.451517	1.25%	2.19%	0.029810	0.07%	2.19%	0.057329	0.13%	2.72%
Overhead Conductor	356.0	1.01%	0.461344	0.47%	1.01%	0.451517	0.46%	2.19%	0.029810	0.07%	2.19%	0.057329	0.13%	1.12%
Underground Conduit	357.0	1.23%	0.461344	0.57%	1.24%	0.451517	0.56%	2.19%	0.029810	0.07%	2.19%	0.057329	0.13%	1.32%
Underground Conductors	358.0	3.18%	0.461344	1.47%	3.18%	0.451517	1.44%	2.19%	0.029810	0.07%	2.19%	0.057329	0.13%	3.10%

(1) As approved in VA Case No. PUE 2006-00065 on May 15, 2007.
Depreciation rates were made effective on January 1, 2006.

(2) Approved by PSC of WV Order dated July 26, 2006 in
Case No. 05-1278-E-PC-PW-42T effective July 1, 2006.

(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.

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 ~~4/1/2013~~ 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	~~1.1600%~~1.27%	~~0.654549~~.646552	~~0.7593%~~.8211%	1.1700%	~~0.152798~~ .139381	~~0.1788%~~.1631%	1.1700%	~~0.192653~~.214067	~~0.2254%~~.2505%	~~1.16~~1.23%~~%~~
Structures & Improvements	352.0	~~1.1500%~~1.32%	~~0.654549~~ .646552	~~0.7527%~~.8534%	1.2700%	~~0.152798~~.139381	~~0.1941%~~.1770%	1.2700%	~~0.192653~~.214067	~~0.2447%~~.2719%	~~1.19~~1.30%~~%~~
Station Equipment	353.0	~~1.4600%~~1.69%	**~~0.654549~~**.646552	~~0.9556%~~1.0927%	1.6500%	~~0.152798~~ .139381	~~0.2521%~~.2300%	1.6500%	~~0.192653~~ .214067	~~0.3179%~~.3532%	~~1.53%~~1.68%
Towers & Fixtures	354.0	~~1.4600%~~1.60%	~~0.654549~~.646552	~~0.9556%~~ 1.0345%	1.4400%	~~0.152798~~.139381	~~0.2200%~~.2007%	1.4400%	~~0.192653~~.214067	~~0.2774%~~.3083%	~~1.45~~1.54%~~%~~
Poles & Fixtures	355.0	~~2.1900%~~2.43%	~~0.654549~~.646552	~~1.4335%~~ 1.5711%	2.3900%	~~0.152798~~.139381	~~0.3652%~~.3331%	2.3900%	~~0.192653~~.214067	~~0.4604%~~.5116%	~~2.26~~2.42%~~%~~
Overhead Conductors	356.0	~~1.2300%~~1.53%	~~0.654549~~.646552	~~0.8051%~~ .9892%	1.4500%	~~0.152798~~.139381	~~0.2216%~~.2021%	1.4500%	~~0.192653~~.214067	~~0.2793%~~.3104%	~~1.31~~1.50%~~%~~
Underground Conduit	357.0	~~1.4500%~~1.56%	~~0.654549~~.646552	~~0.9491%~~ 1.0086%	1.3900%	~~0.152798~~.139381	~~0.2124%~~.1937%	1.3900%	~~0.192653~~.214067	~~0.2678%~~.2976%	~~1.43~~1.50%~~%~~
Underground Conductors	358.0	~~1.3500%~~1.55%	~~0.654549~~.646552	~~0.8836%~~ 1.0022%	1.4600%	~~0.152798~~.139381	~~0.2231%~~.2035%	1.4600%	~~0.192653~~.214067	~~0.2813%~~.3125%	~~1.39~~1.52%~~%~~
Trails & Roads	359.0	~~1.5000%~~1.49%	~~0.654549~~.646552	~~0.9818%~~ .9634%	1.4700%	~~0.152798~~.139381	~~0.2246%~~.2049%	1.4700%	~~0.192653~~.214067	~~0.2832%~~.3147%	~~1.49~~1.48%~~%~~

(1) As approved in Indiana Case No. ~~43231~~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.

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 1/1/2009
FOR SINGLE JURISDICTION COMPANIES
KINGSPORT POWER COMPANY

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

Reference:

Note 1: Rates Approved In Tennessee Regulatory Authority Case No. U-84-7308.

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.

AEP EAST COMPANIES

PJM FORMULA RATE

WORKSHEET P - TRANSMISSION DEPRECIATION RATES

EFFECTIVE AS OF 1/1/2009

FOR SINGLE JURISDICTION COMPANIES

KENTUCKY POWER COMPANY

	PLANT ACCT.	RATES Note 1
TRANSMISSION PLANT		
Structures & Improvements	352.0	1.71%
Station Equipment	353.0	1.71%
Towers & Fixtures	354.0	1.71%
Poles & Fixtures	355.0	1.71%
Overhead Conductors	356.0	1.71%
Underground Conduit	357.0	1.71%
Underground Conductors	358.0	1.71%
Trails & Roads	359.0	1.71%

Reference:

Note 1: Rates Approved in Kentucky Public Service Commission Case No. 91-066.

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 1/1/2009

FOR SINGLE JURISDICTION COMPANIES

WHEELING POWER COMPANY

	PLANT ACCT.	RATES Note 1
TRANSMISSION PLANT		
Structures & Improvements	352.0	2.70%
Station Equipment	353.0	2.70%
Towers & Fixtures	354.0	2.70%
Poles & Fixtures	355.0	2.70%
Overhead Conductors	356.0	2.70%
Underground Conduit	357.0	2.70%
Underground Conductors	358.0	2.70%
Trails & Roads	359.0	2.70%

Note 1: Rates Approved in WV Public Service Commission Case No. PSC 90-243-E-42T.

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.

Attachment D

Spreadsheet setting forth
prior and revised state approved depreciation rates,
and twelve months ending November 30, 2013
annualized depreciation expense

AEPTCo Subsidiaries in PJM
Worksheet - P CALCULATION OF
TOTAL WEIGHTED AVERAGE DEPRECIATION RATES
FOR TRANSMISSION PLANT PROPERTY ACCOUNT
EFFECTIVE AS OF July 1, 2014 [CURRENT RATES]

AEP INDIANA MICHIGAN TRANSMISSION COMPANY

	PLANT ACCT.	**RATES** Note 1
TRANSMISSION PLANT		
Land Rights	350.1	1.27%
Structures & Improvements	352.0	1.32%
Station Equipment	353.0	1.69%
Towers & Fixtures	354.0	1.60%
Poles & Fixtures	355.0	2.43%
Overhead Conductor	356.0	1.53%
Underground Conduit	357.0	1.56%
Underground Conductors	358.0	1.55%
Trails & Roads	359.0	1.49%

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

	Composite Depreciation Rate	I & M	TOTAL
1	T-Plant (FF1 206.58.g)	1,153,823,876	1,153,823,876
2	T-Plant (FF1 206.58.b)	1,115,559,969	1,115,559,969
3	Average (Ln 1+ Ln 2)/2	1,134,691,923	1,134,691,923
4	Depreciation (FF1 336.7.f)	16,178,988	16,178,988
5	Composite Depreciation (Ln 3 / Ln 4)		**1.43%**

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

AEPTCo Subsidiaries in PJM
Worksheet - P CALCULATION OF
TOTAL WEIGHTED AVERAGE DEPRECIATION RATES
FOR TRANSMISSION PLANT PROPERTY ACCOUNT
EFFECTIVE AS OF 7/1/2010 [Prior RATES]

AEP INDIANA MICHIGAN TRANSMISSION COMPANY

	PLANT ACCT.	RATES Note 1
TRANSMISSION PLANT		
Land Rights	350.1	1.16%
Structures & Improvements	352.0	1.15%
Station Equipment	353.0	1.46%
Towers & Fixtures	354.0	1.46%
Poles & Fixtures	355.0	2.19%
Overhead Conductor	356.0	1.23%
Underground Conduit	357.0	1.45%
Underground Conductors	358.0	1.35%
Trails & Roads	359.0	1.50%

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

	Composite Depreciation Rate	I & M	TOTAL
1	T-Plant (FF1 206.58.g)	1,153,823,876	1,153,823,876
2	T-Plant (FF1 206.58.b)	1,115,559,969	1,115,559,969
3	Average (Ln 1+ Ln 2)/2	1,134,691,923	1,134,691,923
4	Depreciation (FF1 336.7.f)	16,178,988	16,178,988
5	Composite Depreciation (Ln 3 / Ln 4)		**1.43%**

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

AEPTCo subsidiaries in PJM
Worksheet - P CALCULATION OF
ANNUALIZED DEPRECIATION EXPENSE
FOR TRANSMISSION PLANT PROPERTY ACCOUNT
Using Current and Prior Depreciation Rates by Account and Plant Balance
Twelve Months Ended November 30, 2013
AEP INDIANA MICHIGAN TRANSMISSION COMPANY

		Original Cost 11/30/2013	Current Rates (A)	Current Annual Dep Expense	Prior Rates (B)	Prior Annual Dep Expense
TRANSMISSION PLANT						
Land Improvements	350.1	17,468.09	1.27%	221.84	1.16%	202.63
Structures & Improvements	352.0	-	1.32%	-	1.15%	-
Station Equipment	353.0	97,891,018.53	1.69%	1,654,358.21	1.46%	1,429,208.87
Towers & Fixtures	354.0	-	1.60%	-	1.46%	-
Poles & Fixtures	355.0	15,270,507.76	2.43%	371,073.34	2.19%	334,424.12
Overhead Conductors	356.0	11,759,993.57	1.53%	179,927.90	1.23%	144,647.92
Underground Conduit	357.0	-	1.56%	-	1.45%	-
Underground Conductors	358.0	-	1.55%	-	1.35%	-
Trails & Roads	359.0	-	1.49%	-	1.50%	-
		124,938,987.95		2,205,581.30		1,908,483.54

AEPTCo subsidiaries in PJM

Worksheet - P

DEPRECIATION RATES

FOR TRANSMISSION PLANT PROPERTY ACCOUNTS

EFFECTIVE AS OF July 1, 2014 [current rates]

AEP OHIO TRANSMISSION COMPANY

	PLANT ACCT.	RATES Note 1
TRANSMISSION PLANT		
Land Rights	350.1	1.49%
Structures & Improvements	352.0	1.53%
Station Equipment	353.0	1.78%
Towers & Fixtures	354.0	1.48%
Poles & Fixtures	355.0	2.30%
Overhead Conductor	356.0	1.42%
Underground Conduit	357.0	1.50%
Underground Conductors	358.0	2.15%
Roads & Trails	359.0	1.60%

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

	Composite Depreciation Rate	CSP	OPCo	TOTAL
1	T-Plant (FF1 206.58.g)	619,883,849	1,164,351,684	1,784,235,533
2	T-Plant (FF1 206.58.b)	570,478,232	1,109,431,387	1,679,909,619
3	Average (Ln 1+ Ln 2)/2	595,181,041	1,136,891,536	1,732,072,576
4	Depreciation (FF1 336.7.f)	12,769,913	25,505,773	38,275,686
5	Composite Depreciation (Ln 3 / Ln 4)			**2.21%**

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

AEPTCo subsidiaries in PJM
Worksheet - P
DEPRECIATION RATES
FOR TRANSMISSION PLANT PROPERTY ACCOUNTS
EFFECTIVE AS OF 7/1/2010 [prior rates]

AEP OHIO TRANSMISSION COMPANY

	PLANT ACCT.	RATES Note 1
TRANSMISSION PLANT		
Land Rights	350.1	1.44%
Structures & Improvements	352.0	1.47%
Station Equipment	353.0	1.71%
Towers & Fixtures	354.0	1.44%
Poles & Fixtures	355.0	2.22%
Overhead Conductor	356.0	1.32%
Underground Conduit	357.0	1.46%
Underground Conductors	358.0	2.08%
Roads & Trails	359.0	1.61%

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

	Composite Depreciation Rate	CSP	OPCo	TOTAL
1	T-Plant (FF1 206.58.g)	619,883,849	1,164,351,684	1,784,235,533
2	T-Plant (FF1 206.58.b)	570,478,232	1,109,431,387	1,679,909,619
3	Average (Ln 1+ Ln 2)/2	595,181,041	1,136,891,536	1,732,072,576
4	Depreciation (FF1 336.7.f)	12,769,913	25,505,773	38,275,686
5	Composite Depreciation (Ln 3 / Ln 4)			**2.21%**

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

AEPTCo subsidiaries in PJM
Worksheet - P CALCULATION OF
ANNUALIZED DEPRECIATION EXPENSE
FOR TRANSMISSION PLANT PROPERTY ACCOUNT
Using Current and Prior Depreciation Rates by Account and Plant Balance
Twelve Months Ended November 30, 2013
AEP OHIO TRANSMISSION COMPANY

		Original Cost 11/30/2013	Current Rates (A)	Current Annual Dep Expense	Prior Rates (B)	Prior Annual Dep Expense
TRANSMISSION PLANT						
Land Improvements	350.1	5,123,273.12	1.49%	76,336.77	1.44%	73,775.13
Structures & Improvements	352.0	1,670,279.45	1.53%	25,555.28	1.47%	24,553.11
Station Equipment	353.0	203,545,873.53	1.78%	3,623,116.55	1.71%	3,480,634.44
Towers & Fixtures	354.0	-	1.48%	-	1.44%	-
Poles & Fixtures	355.0	82,015,707.67	2.30%	1,886,361.28	2.22%	1,820,748.71
Overhead Conductors	356.0	58,881,659.50	1.42%	836,119.56	1.32%	777,237.91
Underground Conduit	357.0	14,684,398.34	1.50%	220,265.98	1.46%	214,392.22
Underground Conductors	358.0	11,604,462.58	2.15%	249,495.95	2.08%	241,372.82
Trails & Roads	359.0	-	1.60%	-	1.61%	-
		377,525,654.19		6,917,251.36		6,632,714.33

Attachment E

Revisions to Section(s) of the
PJM Open Access Transmission Tariff

(Clean Format)

Appendix A to Attachment H-20A

American Electric Power Service Corporation
Docket No. ER10-355

Transmission Formula Rate Settlement
For
AEP Appalachian Transmission Company Inc., AEP Indiana Michigan Transmission Company Inc., AEP Kentucky Transmission Company Inc., AEP Ohio Transmission Company Inc., and AEP West Virginia Transmission Company Inc.

(collectively “AEP” or “the AEP East Transmission Companies”)

Cost of Service and Formula Rate Settlement Principles

The following Cost of Service and Formula Rate Settlement Principles are a part of the Settlement Agreement being filed _______ , 2010 in Docket No. ER10-355 (“the Settlement”):

I. Transmission Formula Rate Design.

A. Applicability of Wholesale Ratemaking Practices.

1. Only those costs that are recoverable pursuant to FERC accounting and/or ratemaking practices may be recovered by the AEP East Transmission 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 Transmission Companies) and non-affiliated customers shall be allocated and charged to customers on a comparable and consistent basis.

   b. 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.

iii. 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, transmission customers (including the AEP East Operating Companies) 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.

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 will be based on a test-year-end rate base style annual transmission revenue requirement ("ATRR") calculation. The initial revenue requirements will be billed July 1, 2010, through June 30, 2011, and will be based on the 2009 expenses and year-end rate base plus projected 2010 calendar transmission plant in service (TPIS) additions. The following year the projected revenue requirements will be based on the 2010 expenses and year-end TPIS balances obtained from the 2010 FF1 plus projected 2011 calendar year TPIS additions.

b. In 2011, the estimated ATRR that was effective during 2010 will be reconciled ("trued-up") with an ATRR that is calculated based on actual 2010 calendar year expenses and rate base reflecting the arithmetic average of the beginning-of-year and end-of-year balances for TPIS and accumulated depreciation. The actual 2010 ATRR ("true-up") to be used for such reconciliation will be posted or otherwise provided to customers in May 2011 at the same time that the projected ATRR to be used for billing purposes during the second half of 2011 (and the first half of 2012) is posted or otherwise provided to customers.

c. For the true-up of prior year charges, AEP East Transmission 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 at the applicable FERC refund interest rates) shall be reflected as an addition to or offset against billed charges for transmission service July 1st of the current year through June 30 of the following 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 Transmission Company will be calculated as 1/8 of transmission-related O&M expense not including any portion of A&G expense allocated to transmission.

3. AEP will provide as a part of its informational filing each May 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 FERC Standard Filing Requirements for Period I Statement AF (Accts. 281, 282, and 283) and Statement AG (Acct. 190). 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.

4. AEP will be permitted to include in Rate Base in the formula rate such portion of AEP's FAS 87 cash investment in Pre-Paid Pension cost recorded in FERC Account 165 as may be incurred for AEP System

employees providing service to the AEP Transmission Companies. 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 transmission cost of service ("TCOS").

C. Expenses

1. The formula rate shall allocate property tax expense based on the methodology of Worksheet Sheet H using the as-filed methodology.

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. The AEP Transmission Companies will record depreciation expense using composites of the depreciation rates attached as Appendix A.1.2, which rates will not be changed absent an Order of the Commission approving such change in a Section 205 or 206 filing at FERC to seek a change in depreciation rates.

6. PBOP Expense

   i. Post employment benefit expenses other than pensions (PBOP) included in each update of the AEP Transmission Companies' formula rate will be fixed based on a rate reflecting the ratio of the AEP System-wide PBOP expense divided by the AEP System-wide total employee direct labor expense (PBOP Rate). The initial PBOP Rate shall be $0.094 per dollar cost of each AEP Transmission Company's direct labor expense.

ii. The calculation of PBOP expense includable in each Annual Update of the formula rate shall be made pursuant to Worksheet O, which is included in Attachment F to the Settlement Agreement, and which will be included in the formula rate. Using Worksheet O, each AEP Transmission Company will, as part of each Annual Update, compare the allowable PBOP expense, based on the PBOP Rate, to its actual PBOP expense in the prior calendar year in order to determine the adjustment required to increase or decrease the actual PBOP expense to the allowable amount.

iii. 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 expenses 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.

iv. During the annual update process conducted in 2014, and every four years thereafter, Worksheet O will be used to determine whether, and if so by what amount, the PBOP allowance rate ($PBOP per $ Direct O&M Labor) should be adjusted going forward for the next four years (PBOP Rate Review). If the Annual Actuarial Report issued during the year of any PBOP Rate Review projects PBOP costs during the next four years that, when allocated to the AEP Transmission Companies based on their projected direct labor expenses over that same projected four-year period, absent a change in the PBOP Rate, will likely cause the AEP East Transmission Companies to over or under collect their cumulative PBOP expenses by more than 20% of the projected next four year's total PBOP expense, taking into account the net over or under collection of such expenses during the previous four years, the PBOP Rate shall be adjusted. In order to determine whether continued use of the then approved PBOP Rate is likely to result in the AEP Companies' incurrence of a cumulative allowance of PBOP costs under the formula rate will result in a cumulative over or under-recovery of actual PBOP expenses exceeding 20% over the subsequent four year period, Worksheet O will be used to determine the following PBOB expense metrics:

(a) the level of cumulative over or under collections of PBOP expense during the time since the PBOP allowance rate was last set, including carrying costs based on the weighted average cost of capital ("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 immediately prior calendar year ("Prior Year WACC"); and

(c) the CNPV of continued collections over the next four years based on the projected AEP Transmission Companies' direct labor expenses and the then effective PBOP allowance rate, assuming a discount rate equal to the Prior Year WACC.

If the absolute value of (a) + (b) - (c) exceeds 20% of (b), then the PBOP allowance rate used in the formula rate calculation shall be changed to the value that will cause the projected result of
(a) + (b) - (c) to equal zero. If the projected over or under collection during the next four years, (a) + (b) - (c), is less than 20% of (b), then the PBOP Rate will continue in effect for the next four years at the then effective rate.

v. If it is determined through the foregoing procedure that the AEP Companies' cumulative PBOP Rate 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 Rate 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 Rate.

vi. The foregoing procedure for required updating of the formula rate's stated PBOP Rate 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.

7. Formation Costs

a. One half of the AEP Transmission Companies' Formation costs incurred before June 30, 2010 will be included in the formula rate, with such amount to be allocated equally among the AEP Transmission Companies and amortized over four years. There will be no carrying charges on the unamortized balance of recoverable Formation costs. Formation costs incurred after June 30, 2010 shall not be included in the transmission formula rates of the AEP Transmission Companies (or the AEP Operating Companies) and shall not be otherwise recoverable in FERC-regulated rates. For purposes of such rate exclusion, post-June 30, 2010 formation costs include, but are not limited to, all costs associated with obtaining any necessary federal, state or local approvals for formation/operation of the AEP Transmission Companies, all costs associated with establishment of the AEP Transmission Companies and the evaluation of how to accomplish same, and any other category of cost that AEP treated as a formation cost for purposes of its request to recover pre-June 30, 2010 formation costs. In its Annual Update filings, AEP Transmission Companies shall provide information sufficient to permit verification that such formation costs have been excluded from the formula rates. AEP reserves the right to seek recovery of post-June 30, 2010 formation costs associated with obtaining necessary state or local approvals (regarding state-related costs) from the applicable state regulatory commission.

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). This ROE shall remain in effect for a period of at least 36 months.

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 formula rate, 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, common and preferred equity, and shall use actual calendar year long term debt interest expenses, preferred dividends, and approved ROE. The long term debt balances and long term debt cost rate shall not include any amounts related to hedging activity.

b. AEP shall use the most recent available FF1 actual end-of-year balances of outstanding long term debt (less the balance of any hedges), preferred equity, and common equity, in the projected ATRR used for billing purposes. 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) 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. However, any amortization of gains or losses on interest rate derivative hedging shall be excluded from long-term-debt cost annual and annualized expenses. AEP will reflect the calculation of its debt cost in Worksheets L and M.

c. AEP is not restricted from hedging at its discretion, and all interest rate hedge gains and losses will be excluded from the formula rate for both the Projected and True-Up rates.

d. AEP East Transmission Companies will establish LTD and Equity investments in the AEP East Transmission Companies as soon as is practicable (actual capital structure and long term debt costs and preferred equity costs). Until that time, the AEP East Transmission Companies will use the actual consolidated (weighted composite) capital structure and LTD cost rate of the AEP Operating Companies in PJM {The AEP Operating Companies in PJM are: Appalachian Power Company, Indiana Michigan Power Company, Kentucky Power Company, Kingsport Power Company, Ohio Power Company, and Wheeling Power Company} subject to a 50% equity ratio cap, as further explained below. Appendix A-1.1 to this Attachment A-1 describes the manner in which the weighted average composite capital structure and cost of long term debt and preferred equity costs of the AEP East Operating Companies in PJM shall be calculated.

e. In transitioning from the use of the proxy composite capital cost of the East Operating Companies in PJM to an actual capital structure, long term debt cost and preferred equity cost, a transitioning East Transmission Company’s actual capital structure and cost rates will be implemented for the Projected TCOS in the first formula rate Annual Update after the issuance of long-term debt or allocation of debt financing from an associated company establishing the transitioning East Company's actual capital structure and cost of debt. The True-Up TCOS in that Annual Update will continue to be based on the East Operating Companies' composite capital structure and LTD cost, and preferred equity costs.

f. The first long term debt in the actual capital structure of an AEP Transmission Company is expected to be an allocation of proceeds from a debt issuance of AEP Transmission Company LLC or AEP Transmission Holding Company LLC (refer to page 7 of Exhibit AEP 100 for the AEPTCo Corporate Structure). The AEP Transmission Companies {The AEP Transmission Companies include the AEP East Transmission Companies and AEP Southwestern Transmission Company Inc., and AEP Oklahoma Transmission Co., Inc.} would draw debt financing from this issuance, as well as equity infusions from AEP Transmission Company LLC or AEP Transmission Holding Company LLC, based on their individual expenditure levels to establish their actual capital structure. The interest rate of this debt financing, along with any associated issuance costs incurred (not to include any costs related to any hedging activities), would define the initial cost of debt for the affected AEP Transmission Companies. This initial debt financing and all subsequent allocations of associated company (AEP Transmission Company LLC or AEP Transmission Holding Company LLC or a higher affiliate in AEP, Inc.) long term debt shall be recorded in Account 430 Advances from Associated Companies in the FERC Form No. 1 reports of the affected AEP Transmission Companies. However, long term debt issuances and equity of the AEP Operating Companies shall not be used to finance debt or equity in the actual capital structure of the AEP Transmission Companies. The debt cost rate of long term debt issuances allocated from associated companies to the AEP Transmission Companies shall be at cost.

g. In the event there is a construction draw down loan, the Companies will adopt the yield to maturity (YTM) approach filed in the PATH Settlement Agreement Docket No. ER08-386-000 in determining the cost of debt for such draw down loan[s], and illustrated in Attachment A.1.3. There is an annual and final (at end of loan) true-up of YTM, consistent with actual debt cost experience. Workpapers showing the calculation of the yield to maturity cost and true-up shall be included in the Annual Update(s) in which such charges are proposed to be included in the Projected rate.

h. When an individual East Transmission Company has an actual capital structure, which is first achieved when the Transmission Company issues its own first long term debt issuance in its own name, or the individual Transmission Company has debt financing specifically allocated from an issuance by AEP Transmission Company LLC or AEP Transmission Holding Company LLC or a higher AEP corporate entity as described in (f) above, the actual long term debt cost and capital structure of that individual East Transmission Company shall be used in the Projected and True Up formula rates for that individual company, subject to a 50% Equity Ratio cap described below and subject to transition year treatment as described in (e) of this section. The True-up and Projected ATRR of the remaining East Transmission Companies which have not yet issued their own long term debt, or received a specific allocation of debt financing by an associated company for the purpose of rate making, shall continue to be based on the consolidated (composite) actual weighted average capital structure, long term debt cost, and preferred equity cost of all the East Operating Companies in PJM (including the costs of the operating company geographically associated with the individual transmission company which has established an actual capital structure and long-term debt cost).

i. In applying the formula rate, the balance amounts of common equity, used in determining the weighted average cost of capital to be used for the AEP East Transmission Companies, shall not exceed 50% percent of the total projected and true-up capitalization ("Equity Cap"), regardless of the actual amounts of common equity capital outstanding. The Equity Cap applies to both the implementation of the consolidated East Operating Company's actual capital structure and to the implementation of an individual East Transmission Company actual capital structure. The Equity Cap can be removed or adjusted only after June 30, 2013 and only through a filing under section 205 or 206 of the Federal Power Act. When applied to the consolidated East Operating Companies' actual capital structure, the individual Operating Company equity caps pursuant to the East Operating Companies' settlement in Docket ER08-1329 shall be applied first before the 50% Equity Cap pursuant to the instant settlement is applied to the weighted composite East Operating Companies' capital structure. The composite weighted average long term debt cost rate of the East Operating Companies, exclusive of hedging costs and Indiana-Michigan Operating Company's spent nuclear fuel disposal funding costs, shall apply.

j. If the percentage of common equity in the East Operating

Companies' composite (consolidated) capitalization or any AEP East Transmission Company's actual 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.

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

1. If the AEP East Transmission 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. No Account 565 costs other than inter-company charges that net out (such as lease arrangements and transmission equalization payments/receipts between AEP companies) will be included in the TCOS, unless first approved by FERC following a separate FPA § 205 filing by AEP.

3. AEP will include in the Annual Update to the formula rate, notification of any change in the use of established allocation factors (change from one

factor to another established allocation factor for a cost applicable to AEP Transmission Companies). Any new allocation factor (not previously approved by the Securities and Exchange Commission or the FERC) will be filed with the FERC for approval in a Section 205 proceeding before being implemented, and AEP will provide notification in the Annual Update of the implementation of a newly created allocation factor that may affect costs allocated to the AEP Transmission Companies. In addition, AEP shall include notification in the Annual Updates of the establishment of any new regulated and un-regulated income-producing affiliates or operating divisions with new income-producing operations.

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.

III. Formula Implementation Protocols

The Formula Rate Implementation Protocols shall be adopted as set forth in Attachment A-2.

Appendix A-1.1

AEP East Consolidated Utility Capital Structure

Consolidation of Operating Companies' Capital Structure @ 12-31-2009

Worksheet Q Page 1

Line		Appalachian Power Company	Indiana Michigan Power Company	Kentucky Power Company	Kingsport Power Company	Ohio Power Company	Wheeling Power Company	AEP East Operating Companies' Consolidated Capital Structure
	Development of Long Term Debt Balances at Year End							
1	Bonds (112.18.c&d)	-	-	-	-	-	-	-
2	Less: Reacquired Bonds (112.19.c&d)	17,500,000	-	-	-	303,000,000	-	320,500,000
3	LT Advances from Assoc. Companies (112.20.c&d)	100,000,000	25,000,000	20,000,000	20,000,000	200,000,000	25,000,000	490,000,000
4	Senior Unsecured Notes (112.21.c&d) Excludes Spent Nuc Fuel Disp Fund	3,419,099,201	1,692,000,000	530,000,000	-	3,351,580,000	-	10,435,424,201
5	Less: Fair Value Hedges (See Note on Ln 7 below)	-	-	-	-	-	-	-
6	**Total Long Term Debt Balance**	3,501,599,201	1,717,000,000	550,000,000	20,000,000	3,248,580,000	25,000,000	10,604,924,201

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

Line		Appalachian Power Company	Indiana Michigan Power Company	Kentucky Power Company	Kingsport Power Company	Ohio Power Company	Wheeling Power Company	AEP East Operating Companies' Consolidated Capital Structure
	Development of Long Term Debt Interest Expense							
8	Interest on Long Term Debt (256-257.33.i)	201,508,637	100,346,371	30,323,070	1,075,000	129,578,994	1,312,500	547,990,827
9	Amort of Debt Discount & Expense (117.63.c)	3,232,592	3,157,632	457,098	-	3,354,846	-	12,043,656
10	Amort of Loss on Reacquired Debt (117.64.c)	991,540	1,596,824	33,649	-	626,793	-	3,992,302
11	Less: Amort of Premium on Debt (117.65.c)	-	-	-	-	-	-	-
12	Less: Amort of Gain on Reacquired Debt (117.66.c)	-	1,712	-	-	-	-	1,712
13	Less: Hedge Interest on pp 256-257(i)	2,569,395	1,551,518	92,956	-	(7,185,191)	-	(2,971,322)
14	**LTD Interest Expense**	203,163,374	103,547,597	30,720,861	1,075,000	140,745,824	1,312,500	566,996,395

Development of Cost of Preferred Stock and Preferred Dividends

15	Dividend Rate (p. 250-251. 7.a)	4.50%	4.125%			4.08%		
16	Par Value (p. 250-251. 8.c)	$ 100.00	$ 100.00			$ 100.00		
17	Shares Outstanding (p.250-251. 8.e)	177,518	55,301			14,595		
18	Monetary Value (Ln 16 * Ln 17)	17,751,800	5,530,100	-	-	1,459,500	-	24,741,400
19	Dividend Amount (Ln 15 * Ln 18)	798,831	228,117	-	-	59,548	-	1,086,495
20	Dividend Rate (p. 250-251. 7.a)		4.12%			4.20%		
21	Par Value (p. 250-251. 8.c)		$ 100.00			$ 100.00		
22	Shares Outstanding (p.250-251. 8.e)		11,055			22,824		
23	Monetary Value (Ln 21 * Ln 22)	-	1,105,500	-	-	2,282,400	-	3,387,900
24	Dividend Amount (Ln 20 * Ln 23)	-	45,547	-	-	95,861	-	141,407
25	Dividend Rate (p. 250-251. 7.a)		4.56%			4.40%		
26	Par Value (p. 250-251. 8.c)		$ 100.00			$ 100.00		
27	Shares Outstanding (p.250-251. 8.e)		14,412			31,482		
28	Monetary Value (Ln 26 * Ln 27)	-	1,441,200	-	-	3,148,200	-	4,589,400
29	Dividend Amount (Ln 25 * Ln 28)	-	65,719	-	-	138,521	-	204,240
30	Dividend Rate (p. 250-251. 7.a)					4.50%		
31	Par Value (p. 250-251. 8.c)					$ 100.00		
32	Shares Outstanding (p.250-251. 8.e)					97,363		
33	Monetary Value (Ln 31 * Ln 32)	-	-	-	-	9,736,300	-	9,736,300
34	Dividend Amount (Ln 30 * Ln 33)	-	-	-	-	438,134	-	438,134
35	**Preferred Stock (Lns 18, 23, 28,33)**	17,751,800	8,076,800	-	-	16,626,400	-	42,455,000
36	**Preferred Dividends (Lns 19, 24, 29,34)**	798,831	339,382	-	-	732,063	-	1,870,276
	Development of Common Equity							
37	Proprietary Capital (112.16.c)	2,789,329,067	1,680,859,984	431,783,697	21,335,470	3,251,321,953	43,904,852	9,578,370,175
38	Less: Preferred Stock (Ln 35 Above)	17,751,800	8,076,800	-	-	16,626,400	-	42,455,000
39	Less: Account 216.1 (112.12.c)	2,593,528	(581,331)	-	-	-	-	4,076,997
40	Less: Account 219.1 (112.15.c)	(50,254,363)				(118,458,118)	(1,749,500)	

			(21,700,504)	(600,942)	5,560			(242,751,398)
41	**Balance of Common Equity**	2,819,238,102	1,695,065,019	432,384,639	21,329,910	3,353,153,671	45,654,352	9,774,589,576
	Calculation of Capital Shares							
42	Long Term Debt (Ln 6 Above)	3,501,599,201	1,717,000,000	550,000,000	20,000,000	3,248,580,000	25,000,000	10,604,924,201
43	Preferred Stock (Ln 35 Above)	17,751,800	8,076,800	-	-	16,626,400	-	42,455,000
44	Common Equity (Ln 41 Above)	2,819,238,102	1,695,065,019	432,384,639	21,329,910	3,353,153,671	45,654,352	9,774,589,576
45	Total Company Structure	6,338,589,103	3,420,141,819	982,384,639	41,329,910	6,618,360,071	70,654,352	20,421,968,777
46	LTD Capital Shares (Ln 42 / Ln 45)	55.24%	50.20%	55.99%	48.39%	49.08%	35.38%	51.93%
47	Preferred Stock Capital Shares (Ln 43 / Ln 45)	0.28%	0.24%	0.00%	0.00%	0.25%	0.00%	0.21%
48	Common Equity Capital Shares (Ln 44 / Ln 45)	44.48%	49.56%	44.01%	51.61%	50.66%	64.62%	47.86%
49	**Equity Capital Share Limit**	50.00%	50.00%	50.00%	100.00%	51.00%	100.00%	50.00%
50	LTD Capital Shares with Capital Equity Cap	55.24%	50.20%	55.99%	48.39%	49.08%	35.38%	51.93%
51	Preferred Stock Capital Shares	0.28%	0.24%	0.00%	0.00%	0.25%	0.00%	0.21%
52	Common Equity Capital Shares with Capital Equity Cap	44.48%	49.56%	44.01%	51.61%	50.66%	64.62%	47.86%
	Calculation of Capital Cost Rate							
53	LTD Capital Cost Rate (Ln 14 / Ln 6)	5.80%	6.03%	5.59%	5.38%	4.33%	5.25%	5.35%
54	Preferred Stock Capital Cost Rate (Ln 36 / Ln 35)	4.50%	4.20%	0.00%	0.00%	4.40%	0.00%	4.41%
55	Common Equity Capital Cost Rate	11.49%	11.49%	11.49%	11.49%	11.49%	11.49%	11.49%
	Calculation of Weighted Capital Cost Rate							
56	LTD Weighted Capital Cost Rate (Ln 50 * Ln 53)	3.21%	3.03%	3.13%	2.60%	2.13%	1.86%	2.78%
57	Preferred Stock Capital Cost Rate (Ln 51 * Ln 54)	0.01%	0.01%	0.00%	0.00%	0.01%	0.00%	0.01%
58	Common Equity Capital Cost Rate (Ln 52 * Ln 55)	5.11%	5.69%	5.06%	5.93%	5.82%	7.42%	5.50%
59	**Total Company Structure**	**8.33%**	**8.73%**	**8.18%**	**8.53%**	**7.96%**	**9.28%**	**8.29%**

Appendix A-1.1

AEP East Consolidated Utility Capital Structure

Consolidation of Operating Companies' Capital Structure @ 12-31-2008

Worksheet Q Page 2

Line		Appalachian Power Company	Indiana Michigan Power Company	Kentucky Power Company	Kingsport Power Company	Ohio Power Company	Wheeling Power Company	AEP East Operating Companies' Consolidated Capital Structure
	Development of Long Term Debt Balances at Year End							
60	Bonds (112.18.c&d)	-	-	-	-	-	-	-
61	Less: Reacquired Bonds (112.19.c&d)	17,500,000	100,000,000	-	-	85,000,000	-	294,745,000
62	LT Advances from Assoc. Companies (112.20.c&d)	100,000,000	-	20,000,000	20,000,000	200,000,000	25,000,000	465,000,000
63	Senior Unsecured Notes (112.21.c&d) Excludes Spent Nuc Fuel Disp Fund	3,114,740,790	1,217,000,000	400,000,000	-	2,594,450,000	-	8,768,935,790
64	Less: Fair Value Hedges (See Note on Ln 66 below)	-	-	-	-	-	-	-
65	**Total Long Term Debt Balance**	3,197,240,790	1,117,000,000	420,000,000	20,000,000	2,709,450,000	25,000,000	8,939,190,790

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

Line		Appalachian Power Company	Indiana Michigan Power Company	Kentucky Power Company	Kingsport Power Company	Ohio Power Company	Wheeling Power Company	AEP East Operating Companies' Consolidated Capital Structure
	Development of Long Term Debt Interest Expense							
67	Interest on Long Term Debt (256-257.33.i)	181,193,862	69,755,551	26,429,625	1,075,000	134,040,796	1,312,500	491,905,445
68	Amort of Debt Discount & Expense (117.63.c)	2,539,613	2,467,181	451,645	-	2,211,243	-	8,755,819
69	Amort of Loss on Reacquired Debt (117.64.c)	1,440,062	2,142,335	33,648	-	1,618,264	-	5,991,748
70	Less: Amort of Premium on Debt (117.65.c)	-	-	-	-	-	-	-
71	Less: Amort of Gain on Reacquired Debt (117.66.c)	-	-	-	-	-	-	-
72	Less: Hedge Interest on pp 256-257(i)	5,001,679	1,547,947	92,956	-	(1,250,297)	-	5,392,285
73	**LTD Interest Expense**	180,171,858	72,817,120	26,821,962	1,075,000	139,120,600	1,312,500	501,260,727

Development of Cost of Preferred Stock and Preferred Dividends

74	Dividend Rate (p. 250-251. 7.a)	4.50%	4.125%			4.08%		
75	Par Value (p. 250-251. 8.c)	$ 100.00	$ 100.00			$ 100.00		
76	Shares Outstanding (p.250-251. 8.e)	177,520	55,335			14,595		
77	Monetary Value (Ln 75 * Ln 76)	17,752,000	5,533,500	-	-	1,459,500	-	24,745,000
78	Dividend Amount (Ln 74 * Ln 77)	798,840	228,257	-	-	59,548	-	1,086,644
79	Dividend Rate (p. 250-251. 7.a)		4.12%			4.20%		
80	Par Value (p. 250-251. 8.c)		$ 100.00			$ 100.00		
81	Shares Outstanding (p.250-251. 8.e)		11,055			22,824		
82	Monetary Value (Ln 80 * Ln 81)	-	1,105,500	-	-	2,282,400	-	3,387,900
83	Dividend Amount (Ln 79 * Ln 82)	-	45,547	-	-	95,861	-	141,407
84	Dividend Rate (p. 250-251. 7.a)		4.56%			4.40%		
85	Par Value (p. 250-251. 8.c)		$ 100.00			$ 100.00		
86	Shares Outstanding (p.250-251. 8.e)		14,412			31,482		
87	Monetary Value (Ln 85 * Ln 86)	-	1,441,200	-	-	3,148,200	-	4,589,400
88	Dividend Amount (Ln 84 * Ln 87)	-	65,719	-	-	138,521	-	204,240
89	Dividend Rate (p. 250-251. 7.a)					4.50%		
90	Par Value (p. 250-251. 8.c)					$ 100.00		
91	Shares Outstanding (p.250-251. 8.e)					97,373		
92	Monetary Value (Ln 90 * Ln 91)	-	-	-	-	9,737,300	-	9,737,300
93	Dividend Amount (Ln 89 * Ln 92)	-	-	-	-	438,179	-	438,179
94	**Preferred Stock (Lns 77, 82, 87,92)**	17,752,000	8,080,200	-	-	16,627,400	-	42,459,600
95	**Preferred Dividends (Lns 78, 83, 88,93)**	798,840	339,522	-	-	732,108	-	1,870,470

Development of Common Equity

96	Proprietary Capital (112.16.c)	2,394,342,663	1,444,357,731	398,008,673	25,031,105	2,438,571,961	37,950,872	7,987,702,880
97	Less: Preferred Stock (Ln 94 Above)	17,752,000	8,080,200	-	-	16,627,400	-	42,459,600

98	Less: Account 216.1 (112.12.c)	2,462,578	(1,510,668)	-	-	-	-	11,153,901
99	Less: Account 219.1 (112.15.c)	(60,225,378)	(20,233,842)	59,584	-	(133,858,575)	(2,464,181)	(263,573,252)
100	**Balance of Common Equity**	2,434,353,463	1,458,022,041	397,949,089	25,031,105	2,555,803,136	40,415,053	8,197,662,631
Calculation of Capital Shares								
101	Long Term Debt (Ln 65 Above)	3,197,240,790	1,117,000,000	420,000,000	20,000,000	2,709,450,000	25,000,000	8,939,190,790
102	Preferred Stock (Ln 94 Above)	17,752,000	8,080,200	-	-	16,627,400	-	42,459,600
103	Common Equity (Ln 100 Above)	2,434,353,463	1,458,022,041	397,949,089	25,031,105	2,555,803,136	40,415,053	8,197,662,631
104	Total Company Structure	5,649,346,253	2,583,102,241	817,949,089	45,031,105	5,281,880,536	65,415,053	17,179,313,021
105	LTD Capital Shares (Ln 101 / Ln 104)	56.59%	43.24%	51.35%	44.41%	51.30%	38.22%	52.03%
106	Preferred Stock Capital Shares (Ln 102 / Ln 104)	0.31%	0.31%	0.00%	0.00%	0.31%	0.00%	0.25%
107	Common Equity Capital Shares (Ln 103 / Ln 104)	43.09%	56.44%	48.65%	55.59%	48.39%	61.78%	47.72%
108	**Equity Capital Share Limit**	50.00%	50.00%	50.00%	100.00%	51.00%	100.00%	50.00%
109	LTD Capital Shares with Capital Equity Cap	56.59%	49.69%	51.35%	44.41%	51.30%	38.22%	53.00%
110	Preferred Stock Capital Shares	0.31%	0.31%	0.00%	0.00%	0.31%	0.00%	0.25%
111	Common Equity Capital Shares with Capital Equity Cap	43.09%	50.00%	48.65%	55.59%	48.39%	61.78%	46.75%
Calculation of Capital Cost Rate								
112	LTD Capital Cost Rate (Ln 73 / Ln 65)	5.64%	6.52%	6.39%	5.38%	5.13%	5.25%	5.61%
113	Preferred Stock Capital Cost Rate (Ln 95 / Ln 94)	4.50%	4.20%	0.00%	0.00%	4.40%	0.00%	4.41%
114	Common Equity Capital Cost Rate	11.49%	11.49%	11.49%	11.49%	11.49%	11.49%	11.49%
Calculation of Weighted Capital Cost Rate								
115	LTD Weighted Capital Cost Rate (Ln 109 * Ln 112)	3.19%	3.24%	3.28%	2.39%	2.63%	2.01%	2.97%
116	Preferred Stock Capital Cost Rate (Ln 110 * Ln 113)	0.01%	0.01%	0.00%	0.00%	0.01%	0.00%	0.01%
117	Common Equity Capital Cost Rate (Ln 111 * Ln 114)	4.95%	5.75%	5.59%	6.39%	5.56%	7.10%	5.37%
118	**Total Company Structure**	**8.15%**	**9.00%**	**8.87%**	**8.77%**	**8.21%**	**9.11%**	**8.35%**

Appendix A-1.1

AEP East Consolidated Utility Capital Structure

Consolidation of Operating Companies' Average Capital Structure

Worksheet Q Page 3

Line		Appalachian Power Company	Indiana Michigan Power Company	Kentucky Power Company	Kingsport Power Company	Ohio Power Company	Wheeling Power Company	AEP East Operating Companies' Consolidated Capital Structure
Development of Average Long Term Debt								
119	Average Bonds (Ln 1 + Ln 60) / 2	-	-	-	-	-	-	-
120	Less: Average Reacquired Bonds (Ln 2 + Ln 61) / 2	17,500,000	50,000,000	-	-	194,000,000	-	307,622,500
121	Average LT Advances from Assoc. Companies (Ln 3 + Ln 62) / 2	100,000,000	12,500,000	20,000,000	20,000,000	200,000,000	25,000,000	477,500,000
122	Average Senior Unsecured Notes (Ln 4 + Ln 63) / 2	3,266,919,996	1,454,500,000	465,000,000	-	2,973,015,000	-	9,602,179,996
123	Less: Average Fair Value Hedges (See Note on Ln 125 below)	-	-	-	-	-	-	-
124	**Average Balance of Long Term Debt**	3,349,419,996	1,417,000,000	485,000,000	20,000,000	2,979,015,000	25,000,000	9,772,057,496
125	NOTE: The balance of fair value hedges on outstanding long term debt are to be excluded from the balance of long term debt included in the formula's capital structure. (p. 257, Column H of the FF1)							
Development of 2009 Long Term Debt Interest Expense								
126	Interest on Long Term Debt (256-257.33.i)	201,508,637	100,346,371	30,323,070	1,075,000	129,578,994	1,312,500	547,990,827
127	Amort of Debt Discount & Expense (117.63.c)	3,232,592	3,157,632	457,098	-	3,354,846	-	12,043,656
128	Amort of Loss on Reacquired Debt (117.64.c)	991,540	1,596,824	33,649	-	626,793	-	3,992,302
129	Less: Amort of Premium on Debt (117.65.c)	-	-	-	-	-	-	-
130	Less: Amort of Gain on Reacquired Debt (117.66.c)	-	1,712	-	-	-	-	1,712

131	Less: Hedge Interest on pp 256-257(i)	2,569,395	1,551,518	92,956	-	(7,185,191)	-	(2,971,322)
132	**2009 LTD Interest Expense**	203,163,374	103,547,597	30,720,861	1,075,000	140,745,824	1,312,500	566,996,395
	2009 Cost of Preferred Stock and Preferred Dividends							
133	Average Balance of Preferred Stock (Ln 35 + Ln 94) / 2	17,751,900	8,078,500	-	-	16,626,900	-	42,457,300
134	2009 Preferred Dividends (Ln 36)	798,831	339,382	-	-	732,063	-	1,870,276
	Development of Average Common Equity							
135	Average Proprietary Capital (Ln 37 + Ln 96) / 2	2,591,835,865	1,562,608,858	414,896,185	23,183,288	2,844,946,957	40,927,862	8,783,036,528
136	Less: Average Preferred Stock (Ln 133 Above)	17,751,900	8,078,500	-	-	16,626,900	-	42,457,300
137	Less: Average Account 216.1 (Ln 39 + Ln 98) / 2	2,528,053	(1,046,000)	-	-	-	-	7,615,449
138	Less: Average Account 219.1 (Ln 40 + Ln 99) / 2	(55,239,871)	(20,967,173)	(270,679)	2,780	(126,158,347)	(2,106,841)	(253,162,325)
139	**Average Balance of Common Equity**	2,626,795,783	1,576,543,530	415,166,864	23,180,508	2,954,478,404	43,034,703	8,986,126,104
	Calculation of Capital Shares							
140	Average Balance of Long Term Debt (Ln 124 Above)	3,349,419,996	1,417,000,000	485,000,000	20,000,000	2,979,015,000	25,000,000	9,772,057,496
141	Average Balance of Preferred Stock (Ln 133 Above)	17,751,900	8,078,500	-	-	16,626,900	-	42,457,300
142	Average Balance of Common Equity (Ln 139 Above)	2,626,795,783	1,576,543,530	415,166,864	23,180,508	2,954,478,404	43,034,703	8,986,126,104
143	Average of Total Company Structure	5,993,967,678	3,001,622,030	900,166,864	43,180,508	5,950,120,304	68,034,703	18,800,640,899
144	Average Balance of LTD Capital Shares (Ln 140 / Ln 143)	55.88%	47.21%	53.88%	46.32%	50.07%	36.75%	51.98%
145	Average Balance of Preferred Stock Capital Shares (Ln 141 / Ln 143)	0.30%	0.27%	0.00%	0.00%	0.28%	0.00%	0.23%
146	Average Balance of Common Equity Capital Shares (Ln 142 / Ln 143)	43.82%	52.52%	46.12%	53.68%	49.65%	63.25%	47.80%
147	**Equity Capital Share Limit**	50.00%	50.00%	50.00%	100.00%	51.00%	100.00%	50.00%
148	LTD Capital Shares with Capital Equity Cap	55.88%	49.73%	53.88%	46.32%	50.07%	36.75%	52.38%
149	Preferred Stock Capital Shares	0.30%	0.27%	0.00%	0.00%	0.28%	0.00%	0.23%

150	Common Equity Capital Shares with Capital Equity Cap	43.82%	50.00%	46.12%	53.68%	49.65%	63.25%	47.39%
	<u>Calculation of Capital Cost Rate</u>							
151	LTD Capital Cost Rate (Ln 132 / Ln 124)	6.07%	7.31%	6.33%	5.38%	4.72%	5.25%	5.80%
152	Preferred Stock Capital Cost Rate (Ln 134 / Ln 133)	4.50%	4.20%	0.00%	0.00%	4.40%	0.00%	4.41%
153	Common Equity Capital Cost Rate	11.49%	11.49%	11.49%	11.49%	11.49%	11.49%	11.49%
	<u>Calculation of Weighted Capital Cost Rate</u>							
154	LTD Weighted Capital Cost Rate (Ln 148 * Ln 151)	3.39%	3.63%	3.41%	2.49%	2.37%	1.93%	3.04%
155	Preferred Stock Capital Cost Rate (Ln 149 * Ln 152)	0.01%	0.01%	0.00%	0.00%	0.01%	0.00%	0.01%
156	Common Equity Capital Cost Rate (Ln 150 * Ln 153)	5.04%	5.75%	5.30%	6.17%	5.71%	7.27%	5.45%
157	**ACTUAL WEIGHTED AVG COST OF CAPITAL**	**8.44%**	**9.39%**	**8.71%**	**8.66%**	**8.08%**	**9.20%**	**8.49%**

Appendix A.1.2

		AEP Appalachian Transmission Co	AEP Indiana Michigan Transmission Co	AEP Kentucky Transmission Co	AEP Ohio Transmission Co
350	Land Rights		1.27%	1.71%	1.49%
352	Structures & Improvements	1.55%	1.32%	1.71%	1.53%
353	Station Equipment	1.95%	1.69%	1.71%	1.78%
354	Towers & Fixtures	1.14%	1.60%	1.71%	1.48%
355	Poles & Fixtures	2.77%	2.43%	1.71%	2.30%
356	OH Conductors & Devices	1.01%	1.53%	1.71%	1.42%
357	Underground Conduit	1.23%	1.56%	1.71%	1.50%
358	Underground Conductor	3.18%	1.55%	1.71%	2.15%
359	Roads & Trails		1.49%	1.71%	1.60%

*For the states of Kentucky, West Virginia, Virginia, Indiana and Michigan, the formula rate will use rates based on the last approved depreciation study for the applicable jurisdiction (KPCo, APCo, or I&M). For example, rates for the 2004 I&M depreciation study will be used for Indiana and Michigan.

Ohio’s rates are a composite rate calculated as the average of the APCo, I&M and KPCo rates. AEP's rates may only be changed in a Section 205/206 proceeding based on new studies. This filing may be a single issue proceeding.

Appendix A.1.3

Illustration of Construction Draw Down Loan

Appendix A.1.3 - Financing Costs for Long Term Debt using the Internal Rate of Return Methodology – AEP Transco

HYPOTHETICAL EXAMPLE

AEP Transco anticipates its financing will be a 7 year loan, where by AEP Transco pays Origination Fees of $7.9 million and a Commitments Fee of 0.375% on the undrawn principle.
Consistent with GAAP, AEP Transco will amortize the Origination Fees and Commitments Fees using the standard Internal Rate of Return formula below.
Each year, AEP Transco will true up the amounts withdrawn, the interest paid in the year, Origination Fees, Commitments Fees, and total loan amount on this attachment.

Total Loan Amount	**$ 600,000,000**

Internal Rate of Return[1]	**6.65%**
Based on following Financial Formula[2]:	
NPV = 0 =	

Origination Fees	
Underwriting Discount	-
Arrangement Fee	2,000,000
Upfront Fee	4,400,000
Rating Agency Fee	200,000
Legal Fees	1,250,000
Total Issuance Expense	**7,850,000**

Annual Rating Agency Fee	200,000
Annual Bank Agency Fee	75,000
Revolving Credit Commitment Fee	0.375%

	2008	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**
LIBOR Rate	4.0610%	4.0610%	4.0610%	4.0610%	4.0610%	4.0610%	4.0610%
Spread	1.875%	1.875%	1.875%	1.875%	1.875%	1.875%	1.875%
Interest Rate	5.94%	5.94%	5.94%	5.94%	5.94%	5.94%	5.94%

(A) **Year**	(B)	(C) **Capital Expenditures ($000's)**	(D) **Principle Drawn In Quarter ($000's)**	(E) **Principle Drawn To Date ($000's)**	(F) **Interest Expense ($000's)**	(G) **Origination Fees ($000's)**	(H) **Commitment & Utilization Fee ($000's)**	(I) **Net Cash Flows ($000's)** **(D-F-G-H)**
Prior to 11/2008		16,529						
30/11/2008	Q4	8,923		-	-			-
15/02/2009	Q1	14,636	20,044	20,044	-	125		19,919
15/05/2009	Q2	17,119	8,560	28,604	297			8,262

15/08/2009	Q3	46,132	23,066	51,670	424			22,642
15/11/2009	Q4	62,740	31,370	83,040	767			30,603
15/02/2010	Q1	132,393	66,197	149,236	1,232	7,725	553	56,686
15/05/2010	Q2	132,393	66,197	215,433	2,215		491	63,490
15/08/2010	Q3	132,393	66,197	281,629	3,197		429	62,570
15/11/2010	Q4	132,393	66,197	347,826	4,179		367	61,650
15/02/2011	Q1	70,588	35,294	383,120	5,162		305	29,827
15/05/2011	Q2	70,588	35,294	418,414	5,685		272	29,336
15/08/2011	Q3	70,588	35,294	453,708	6,209		239	28,846
15/11/2011	Q4	70,588	35,294	489,002	6,733		206	28,355
15/022012	Q1	51,885	25,943	514,944	7,257		173	18,513
15/05/2012	Q2	51,885	25,943	540,887	7,642		148	18,152
15/08/2012	Q3	51,885	25,943	566,829	8,027		124	17,792
15/11/2012	Q4	51,885	25,943	592,772	8,412		100	17,431
15/02/2013	Q1	11,122	7,228	600,000	8,797		76	(1,644)
15/05/2013	Q2			600,000	8,904		69	(8,973)
15/08/2013	Q3			600,000	8,904		69	(8,973)
15/11/2013	Q4			600,000	8,904		69	(8,973)
15/02/2014	Q1			600,000	8,904		69	(8,973)
15/05/2014	Q2			600,000	8,904		69	(8,973)
15/08/2014	Q3			600,000	8,904		69	(8,973)
15/11/2014	Q4			600,000	8,904		69	(8,973)
15/02/2015	Q1			600,000	8,904		-	(608,903)

[1] The IRR is the Debt Cost shown on Page 5, Line 118 of Rate Formula Template.

[2] The IRR is a discount rate that makes the net present value of a series of cash flows equal to zero. The IRR equation can only be solved through iterations performed by a computer program (i.e.NPV function with goal seek in a spreadsheet program).

Appendix A.1.3

Hypothetical Example of Final True-Up of Interest Rates and Interest Calculations for the Construction Loan

To be Prepared on 8/15/2013 (hypothetical date)

SUMMARY

YEAR	Estimated Effective cost of debt used in forecast/true up	Final Effective cost of debt for the construction loan:	Hypothetical Revenue Requirement: Based on Estimated Effective cost of debt	Hypothetical Revenue Requirement: Based on Actual Effective cost of debt	Over (Under) Recovery	Hypothetical Monthly Interest Rate applicable over the ATRR period	Total Amount of Construction Loan Related True-Up included in rates effective Jan 2014 (Refund)/Owed
2008	7.18%	7.00%	$ 2,500,000.00	$ 2,400,000.00	$ 100,000.00	0.550%	$ (148,288.33)
2009	6.8%	7.00%	$5,000,000.00	$5,150,000.00	$ (150,000.00)	0.560%	$ 209,670.43
2010	7.2%	7.00%	$8,300,000.00	$8,200,000.00	$ 100,000.00	0.540%	$ (131,109.09)
2011	7.3%	7.00%	$12,300,000.00	$12,000,000.00	$ 300,000.00	0.580%	$ (368,656.73)
2012*	7.1%	6.83%	$18,000,000.00	$17,900,000.00	$ 100,000.00	0.570%	$ (114,946.28)
2013**	6.50%	6.50%	$25,000,000.00	$25,000,000.00	$ -		
2014**	6.50%	6.50%					$ (553,329.99)

**** Assumes that the construction loan is retired on Sept 1, 2012***

***** Assumes permanent debt structure is put in place on Sept 1, 2012 with effective rate of 6.5%***

Note: True-Up period is 2008 - 2012, with the true-up amount included in 2014 forecasted ATRR. Final effective cost of debt for 2012 is computed as follows: ((7%*243days)+(6.5%*122days))/365days

Calculation of Applicable Interest Expense for each ATRR period

Calculation of Interest for 2008 True-Up Period

An over or under collection will be recovered prorata over 2008, held for 2009, 2010, 2011, 2012, 2013 and returned prorate over 2014

Interest Rate on Amount of Refunds or Surcharges from 35.19a		Over (Under) Recovery Plus Interest	Hypothetical Monthly Interest Rate	Months	Calculated Interest (Monthly)	Amortization	Surcharge (Refund) Owed
January	Year 2008	-	0.5500%	12.00	-		-
February	Year 2008	-	0.5500%	11.00	-		-
March	Year 2008	10,000	0.5500%	10.00	(550)		(10,550)
April	Year 2008	10,000	0.5500%	9.00	(495)		(10,495)
May	Year 2008	10,000	0.5500%	8.00	(440)		(10,440)
June	Year 2008	10,000	0.5500%	7.00	(385)		(10,385)
July	Year 2008	10,000	0.5500%	6.00	(330)		(10,330)
August	Year 2008	10,000	0.5500%	5.00	(275)		(10,275)
September	Year 2008	10,000	0.5500%	4.00	(220)		(10,220)
October	Year 2008	10,000	0.5500%	3.00	(165)		(10,165)
November	Year 2008	10,000	0.5500%	2.00	(110)		(10,110)
December	Year 2008	10,000	0.5500%	1.00	(55)		(10,055)
					(3,025)		**(103,025)**

					Annual		
January through December	Year 2009	(103,025)	0.5600%	12.00	(6,923)		**(109,948)**
January through December	Year 2010	(109,948)	0.5400%	12.00	(7,125)		**(117,073)**
January through December	Year 2011	(117,073)	0.5800%	12.00	(8,148)		**(125,221)**
January through December	Year 2012	(125,221)	0.5700%	12.00	(8,565)		**(133,786)**
January through December	Year 2013	(133,786)	0.5700%	12.00	(9,151)		**(142,937)**
<u>Over (Under) Recovery Plus Interest Amortized and Recovered Over 12 Months</u>					**Monthly**		
January	Year 2014	**142,937**	0.5700%		(815)	(12,357)	(131,395)
February	Year 2014	131,395	0.5700%		(749)	(12,357)	(119,786)
March	Year 2014	119,786	0.5700%		(683)	(12,357)	(108,112)
April	Year 2014	108,112	0.5700%		(616)	(12,357)	(96,371)
May	Year 2014	96,371	0.5700%		(549)	(12,357)	(84,563)
June	Year 2014	84,563	0.5700%		(482)	(12,357)	(72,687)
July	Year 2014	72,687	0.5700%		(414)	(12,357)	(60,744)
August	Year 2014	60,744	0.5700%		(346)	(12,357)	(48,733)
September	Year 2014	48,733	0.5700%		(278)	(12,357)	(36,653)
October	Year 2014	36,653	0.5700%		(209)	(12,357)	(24,505)
November	Year 2014	24,505	0.5700%		(140)	(12,357)	(12,287)
December	Year 2014	12,287	0.5700%		(70)	(12,357)	0
					(5,351)		

Total Amount of True-Up Adjustment for 2008 ATRR	$	(148,288)
Less Over (Under) Recovery	$	100,000
Total Interest	$	(48,288)

Appendix A.1.3

Hypothetical Example of Final True-Up of Interest Rates and Interest Calculations for the Construction Loan

<u>Calculation of Interest for 2009 True-Up Period</u>

An over or under collection will be recovered prorata over 2009, held for 2010, 2011, 2012, 2013 and returned prorate over 2014

					Monthly	
January	Year 2009	(12,500)	0.5600%	12.00	840	13,340
February	Year 2009	(12,500)	0.5600%	11.00	770	13,270
March	Year 2009	(12,500)	0.5600%	10.00	700	13,200
April	Year 2009	(12,500)	0.5600%	9.00	630	13,130
May	Year 2009	(12,500)	0.5600%	8.00	560	13,060
June	Year 2009	(12,500)	0.5600%	7.00	490	12,990
July	Year 2009	(12,500)	0.5600%	6.00	420	12,920
August	Year 2009	(12,500)	0.5600%	5.00	350	12,850
September	Year 2009	(12,500)	0.5600%	4.00	280	12,780
October	Year 2009	(12,500)	0.5600%	3.00	210	12,710
November	Year 2009	(12,500)	0.5600%	2.00	140	12,640
December	Year 2009	(12,500)	0.5600%	1.00	70	12,570
					5,460	**155,460**
					Annual	
January through December	Year 2010	155,460	0.5400%	12.00	10,074	**165,534**
January through December	Year 2011	165,534	0.5800%	12.00	11,521	**177,055**
January through December	Year 2012	177,055	0.5700%	12.00	12,111	**189,166**
January through December	Year 2013	189,166	0.5700%	12.00	12,939	**202,104**

Over (Under) Recovery Plus Interest Amortized and Recovered Over 12 Months					**Monthly**		
January	Year 2014	**(202,104)**	0.5700%		1,152	17,473	185,784
February	Year 2014	(185,784)	0.5700%		1,059	17,473	169,370
March	Year 2014	(169,370)	0.5700%		965	17,473	152,863
April	Year 2014	(152,863)	0.5700%		871	17,473	136,262
May	Year 2014	(136,262)	0.5700%		777	17,473	119,566
June	Year 2014	(119,566)	0.5700%		682	17,473	102,775
July	Year 2014	(102,775)	0.5700%		586	17,473	85,888
August	Year 2014	(85,888)	0.5700%		490	17,473	68,905
September	Year 2014	(68,905)	0.5700%		393	17,473	51,826
October	Year 2014	(51,826)	0.5700%		295	17,473	34,649
November	Year 2014	(34,649)	0.5700%		197	17,473	17,374
December	Year 2014	(17,374)	0.5700%		99	17,473	(0)
					7,566		
Total Amount of True-Up Adjustment for 2009 ATRR						$ 209,670	
Less Over (Under) Recovery						$ (150,000)	
Total Interest						$ 59,670	

Calculation of Interest for 2010 True-Up Period						
An over or under collection will be recovered prorata over 2010, held for 2011, 2012, 2013 and returned prorate over 2014					**Monthly**	
January	Year 2010	8,333	0.5400%	12.00	(540)	(8,873)
February	Year 2010	8,333	0.5400%	11.00	(495)	(8,828)
March	Year 2010	8,333	0.5400%	10.00	(450)	(8,783)
April	Year	8,333	0.5400%	9.00	(405)	(8,738)

	2010						
May	Year 2010	8,333	0.5400%	8.00	(360)		(8,693)
June	Year 2010	8,333	0.5400%	7.00	(315)		(8,648)
July	Year 2010	8,333	0.5400%	6.00	(270)		(8,603)
August	Year 2010	8,333	0.5400%	5.00	(225)		(8,558)
September	Year 2010	8,333	0.5400%	4.00	(180)		(8,513)
October	Year 2010	8,333	0.5400%	3.00	(135)		(8,468)
November	Year 2010	8,333	0.5400%	2.00	(90)		(8,423)
December	Year 2010	8,333	0.5400%	1.00	(45)		(8,378)
					(3,510)		**(103,510)**
					Annual		
January through December	Year 2011	(103,510)	0.5800%	12.00	(7,204)		**(110,714)**
January through December	Year 2012	(110,714)	0.5700%	12.00	(7,573)		**(118,287)**
January through December	Year 2013	(118,287)	0.5700%	12.00	(8,091)		**(126,378)**
Over (Under) Recovery Plus Interest Amortized and Recovered Over 12 Months					**Monthly**		
January	Year 2014	**126,378**	0.5700%		(720)	(10,926)	(116,173)
February	Year 2014	116,173	0.5700%		(662)	(10,926)	(105,909)
March	Year 2014	105,909	0.5700%		(604)	(10,926)	(95,587)
April	Year 2014	95,587	0.5700%		(545)	(10,926)	(85,206)
May	Year 2014	85,206	0.5700%		(486)	(10,926)	(74,766)
June	Year 2014	74,766	0.5700%		(426)	(10,926)	(64,266)
July	Year 2014	64,266	0.5700%		(366)	(10,926)	(53,707)
August	Year 2014	53,707	0.5700%		(306)	(10,926)	(43,087)
September	Year 2014	43,087	0.5700%		(246)	(10,926)	(32,407)
October	Year 2014	32,407	0.5700%		(185)	(10,926)	(21,666)
November	Year 2014	21,666	0.5700%		(123)	(10,926)	(10,864)
December	Year 2014	10,864	0.5700%		(62)	(10,926)	0
					(4,731)		
Total Amount of True-Up Adjustment for 2010 ATRR						$ (131,109)	
Less Over (Under) Recovery						$ 100,000	
Total Interest							$ (31,109)

Appendix A.1.3

Hypothetical Example of Final True-Up of Interest Rates and Interest Calculations for the Construction Loan

Calculation of Interest for 2011 True-Up Period

An over or under collection will be recovered prorata over 2011, held for 2012, 2013 and returned prorate over 2014

						Monthly	
January	Year 2011		25,000	0.5800%	12.00	(1,740)	(26,740)
February	Year 2011		25,000	0.5800%	11.00	(1,595)	(26,595)
March	Year 2011		25,000	0.5800%	10.00	(1,450)	(26,450)
April	Year 2011		25,000	0.5800%	9.00	(1,305)	(26,305)
May	Year 2011		25,000	0.5800%	8.00	(1,160)	(26,160)
June	Year 2011		25,000	0.5800%	7.00	(1,015)	(26,015)
July	Year 2011		25,000	0.5800%	6.00	(870)	(25,870)
August	Year 2011		25,000	0.5800%	5.00	(725)	(25,725)
September	Year 2011		25,000	0.5800%	4.00	(580)	(25,580)
October	Year 2011		25,000	0.5800%	3.00	(435)	(25,435)
November	Year 2011		25,000	0.5800%	2.00	(290)	(25,290)
December	Year 2011		25,000	0.5800%	1.00	(145)	(25,145)
						(11,310)	**(311,310)**
						Annual	
January through December	Year 2012	(311,310)		0.5700%	12.00	(21,294)	**(332,604)**
January through December	Year 2013	(332,604)		0.5700%	12.00	(22,750)	**(355,354)**

<u>Over (Under) Recovery Plus Interest Amortized and Recovered Over 12 Months</u>

				Monthly		
January	Year 2014	**355,354**	0.5700%	(2,026)	(30,721)	(326,658)
February	Year 2014	326,658	0.5700%	(1,862)	(30,721)	(297,798)
March	Year 2014	297,798	0.5700%		(30,721)	(268,774)

				(1,697)		
April	Year 2014	268,774	0.5700%	(1,532)	(30,721)	(239,585)
May	Year 2014	239,585	0.5700%	(1,366)	(30,721)	(210,229)
June	Year 2014	210,229	0.5700%	(1,198)	(30,721)	(180,706)
July	Year 2014	180,706	0.5700%	(1,030)	(30,721)	(151,015)
August	Year 2014	151,015	0.5700%	(861)	(30,721)	(121,154)
September	Year 2014	121,154	0.5700%	(691)	(30,721)	(91,123)
October	Year 2014	91,123	0.5700%	(519)	(30,721)	(60,921)
November	Year 2014	60,921	0.5700%	(347)	(30,721)	(30,547)
December	Year 2014	30,547	0.5700%	(174)	(30,721)	0
						(13,303)

Total Amount of True-Up Adjustment for 2011 ATRR	$ (368,657)
Less Over (Under) Recovery	$ 300,000
Total Interest	$ (68,657)

<u>Calculation of Interest for 2012 True-Up Period</u>

An over or under collection will be recovered prorata over 2012, held for 2013 and returned prorate over 2014

			Monthly			
January	Year 2012	8,333	0.5700%	12.00	(570)	(8,903)
February	Year 2012	8,333	0.5700%	11.00	(523)	(8,856)
March	Year 2012	8,333	0.5700%	10.00	(475)	(8,808)
April	Year 2012	8,333	0.5700%	9.00	(428)	(8,761)
May	Year 2012	8,333	0.5700%	8.00	(380)	(8,713)
June	Year 2012	8,333	0.5700%	7.00	(333)	(8,666)
July	Year 2012	8,333	0.5700%	6.00	(285)	(8,618)
August	Year 2012	8,333	0.5700%	5.00	(238)	(8,571)

September	Year 2012	8,333	0.5700%	4.00	(190)	(8,523)
October	Year 2012	8,333	0.5700%	3.00	(143)	(8,476)
November	Year 2012	8,333	0.5700%	2.00	(95)	(8,428)
December	Year 2012	8,333	0.5700%	1.00	(48)	(8,381)
					(3,705)	**(103,705)**
					Annual	
January through December	Year 2013	(103,705)	0.5700%	12.00	(7,093)	**(110,798)**

<u>Over (Under) Recovery Plus Interest Amortized and Recovered Over 12 Months</u>

				Monthly		
January	Year 2014	**110,798**	0.5700%	(632)	(9,579)	(101,851)
February	Year 2014	101,851	0.5700%	(581)	(9,579)	(92,853)
March	Year 2014	92,853	0.5700%	(529)	(9,579)	(83,803)
April	Year 2014	83,803	0.5700%	(478)	(9,579)	(74,702)
May	Year 2014	74,702	0.5700%	(426)	(9,579)	(65,549)
June	Year 2014	65,549	0.5700%	(374)	(9,579)	(56,344)
July	Year 2014	56,344	0.5700%	(321)	(9,579)	(47,086)
August	Year 2014	47,086	0.5700%	(268)	(9,579)	(37,776)
September	Year 2014	37,776	0.5700%	(215)	(9,579)	(28,412)
October	Year 2014	28,412	0.5700%	(162)	(9,579)	(18,995)
November	Year 2014	18,995	0.5700%	(108)	(9,579)	(9,525)
December	Year 2014	9,525	0.5700%	(54)	(9,579)	0
				(4,148)		

Total Amount of True-Up Adjustment for 2012 ATRR	$ (114,946)
Less Over (Under) Recovery	$ 100,000
Total Interest	$ (14,946)

Attachment F

Revisions to Section(s) of the
PJM Open Access Transmission Tariff

(Marked / Redline Format)

Appendix A to Attachment H-20A

American Electric Power Service Corporation
Docket No. ER10-355

Transmission Formula Rate Settlement
For
AEP Appalachian Transmission Company Inc., AEP Indiana Michigan Transmission Company Inc., AEP Kentucky Transmission Company Inc., AEP Ohio Transmission Company Inc., and AEP West Virginia Transmission Company Inc.

(collectively "AEP" or "the AEP East Transmission Companies")

Cost of Service and Formula Rate Settlement Principles

The following Cost of Service and Formula Rate Settlement Principles are a part of the Settlement Agreement being filed _______ , 2010 in Docket No. ER10-355 ("the Settlement"):

~~I.~~ **I.** **Transmission Formula Rate Design.**

~~A.~~ A. Applicability of Wholesale Ratemaking Practices.

~~1.~~ ~~–~~1. Only those costs that are recoverable pursuant to FERC accounting and/or ratemaking practices may be recovered by the AEP East Transmission Companies through its FERC transmission formula rate.

~~2.~~ 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.~~ 3. Costs of transmission studies

~~a.~~ 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 Transmission Companies) and non-affiliated customers shall be allocated and charged to customers on a comparable and consistent basis.

~~b.~~ b. ~~–~~The costs of such studies shall be accounted for in one of the following ways:

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

~~ii~~ 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.

~~iii~~ iii. 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.~~ 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, transmission customers (including the AEP East Operating Companies) 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.

~~B.~~ B. Rate Base

~~1.~~ 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.~~ a. The revenue requirements billed each July and running through June of the next year will be based on a test-year-end rate base style annual transmission revenue requirement ("ATRR") calculation. The initial revenue requirements will be billed July 1, 2010, through June 30, 2011, and will be based on the 2009 expenses and year-end rate base plus projected 2010 calendar transmission plant in service (TPIS) additions. The following year the projected revenue requirements will be based on the 2010 expenses and year-end TPIS balances obtained from the 2010 FF1 plus projected 2011 calendar year TPIS additions.

~~b.~~ b. In 2011, the estimated ATRR that was effective during 2010 will be reconciled ("trued-up") with an ATRR that is calculated based on actual 2010 calendar year expenses and rate base reflecting the arithmetic average of the beginning-of-year and end-of-year balances for TPIS and accumulated depreciation. The actual 2010 ATRR ("true-up") to be used for such reconciliation will be posted or otherwise provided to customers in May 2011 at the same time that the projected ATRR to be used for billing purposes during the second half of 2011 (and the first half of 2012) is posted or otherwise provided to customers.

~~c.~~ c. For the true-up of prior year charges, AEP East Transmission 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 at the applicable FERC refund interest rates) shall be reflected as an addition to or offset against billed charges for transmission service July 1st of the current year through June 30 of the following year. The interest rate will be calculated as per section 35.19a of the Commission's regulations.

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

~~2.~~ 2. Cash working capital for each AEP East Transmission Company will be calculated as 1/8 of transmission-related O&M expense not including any portion of A&G expense allocated to transmission.

~~3.~~ 3. AEP will provide as a part of its informational filing each May 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 FERC Standard Filing Requirements for Period I Statement AF (Accts. 281, 282, and 283) and Statement AG (Acct. 190). 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.

~~4.~~ 4. AEP will be permitted to include in Rate Base in the formula rate such portion of AEP's FAS 87 cash investment in Pre-Paid Pension cost recorded in FERC Account 165 as may be incurred for AEP System employees providing service to the AEP Transmission Companies. 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 transmission cost of service ("TCOS").

~~C.~~ C. Expenses

~~1.~~ 1. The formula rate shall allocate property tax expense based on the methodology of Worksheet Sheet H using the as-filed methodology.

~~2.~~ 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.~~ 3. The formula shall include only expenses that are directly related to or properly allocable to transmission service.

~~4.~~ 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.~~ 5. The AEP Transmission Companies will record depreciation expense using composites of the depreciation rates attached as Appendix A.1.2, which rates will not be changed absent an Order of the Commission approving such change in a Section 205 or 206 filing at FERC to seek a change in depreciation rates.

~~6.~~ 6. PBOP Expense

~~i.~~ i. Post employment benefit expenses other than pensions (PBOP) included in each update of the AEP Transmission Companies' formula rate will be fixed based on a rate reflecting the ratio of the AEP System-wide PBOP expense divided by the

AEP System-wide total employee direct labor expense (PBOP Rate). The initial PBOP Rate shall be $0.094 per dollar cost of each AEP Transmission Company's direct labor expense.

~~ii~~ ii. The calculation of PBOP expense includable in each Annual Update of the formula rate shall be made pursuant to Worksheet O, which is included in Attachment F to the Settlement Agreement, and which will be included in the formula rate. Using Worksheet O, each AEP Transmission Company will, as part of each Annual Update, compare the allowable PBOP expense, based on the PBOP Rate, to its actual PBOP expense in the prior calendar year in order to determine the adjustment required to increase or decrease the actual PBOP expense to the allowable amount.

~~iii.~~ iii. 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 expenses 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.

iv. During the annual update process conducted in 2014, and every four years thereafter, Worksheet O will be used to determine whether, and if so by what amount, the PBOP allowance rate ($PBOP per $ Direct O&M Labor) should be adjusted going forward for the next four years (PBOP Rate Review). If the Annual Actuarial Report issued during the year of any PBOP Rate Review projects PBOP costs during the next four years that, when allocated to the AEP Transmission Companies based on their projected direct labor expenses over that same projected four-year period, absent a change in the PBOP Rate, will likely cause the AEP East Transmission Companies to over or under collect their cumulative PBOP expenses by more than 20% of the projected next four year's total PBOP expense, taking into account the net over or under collection of such expenses during the previous four years, the PBOP Rate shall be adjusted. In order to determine whether continued use of the then approved PBOP Rate is likely to result in the AEP Companies' incurrence of a cumulative allowance of PBOP costs under the formula rate will result in a cumulative over or under-recovery of actual PBOP expenses exceeding 20% over the subsequent four year period, Worksheet O will be used to determine the following PBOB expense metrics:

(a) the level of cumulative over or under collections of PBOP expense during the time since the PBOP allowance rate was last set, including carrying costs based on the weighted average cost of capital ("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 immediately prior calendar year ("Prior Year WACC"); and

(c) the CNPV of continued collections over the next four years based on the projected AEP Transmission Companies' direct labor expenses and the then effective PBOP allowance rate, assuming a discount rate equal to the Prior Year WACC.

If the absolute value of (a) + (b) - (c) exceeds 20% of (b), then the PBOP allowance rate used in the formula rate calculation shall be changed to the value that will cause the projected result of
(a) + (b) - (c) to equal zero. If the projected over or under collection during the next four years, (a) + (b) - (c), is less than 20% of (b), then the PBOP Rate will continue in effect for the next four years at the then effective rate.

v. If it is determined through the foregoing procedure that the AEP Companies' cumulative PBOP Rate 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 Rate 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 Rate.

vi. The foregoing procedure for required updating of the formula rate's stated PBOP Rate 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.

~~7.~~ 7. Formation Costs

a. One half of the AEP Transmission Companies' Formation costs incurred before June 30, 2010 will be included in the formula rate, with such amount to be allocated equally among the AEP Transmission Companies and amortized over four years. There will be no carrying charges on the unamortized balance of recoverable Formation costs. Formation costs incurred after June 30, 2010 shall not be included in the transmission formula rates of the AEP Transmission Companies (or the AEP Operating Companies) and shall not be otherwise recoverable in FERC-regulated rates. For purposes of such rate exclusion, post-June 30, 2010 formation costs include, but are not limited to, all costs associated with obtaining any necessary federal, state or local approvals for formation/operation of the AEP Transmission Companies, all costs associated with establishment of the AEP Transmission Companies and the evaluation of how to accomplish same, and any other category of cost that AEP treated as a formation cost for purposes of its request to recover pre-June 30, 2010 formation costs. In its Annual Update filings, AEP Transmission Companies shall provide information sufficient to permit verification that such formation costs have been excluded from the formula rates. AEP reserves the right to seek recovery of post-June 30, 2010 formation costs associated with obtaining necessary state or local approvals (regarding state-related costs) from the applicable state regulatory commission.

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

~~1.~~ 1. Return on Equity

~~a.~~ 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). This ROE shall remain in effect for a period of at least 36 months.

~~b.~~ 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 formula rate, 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.~~ 2. Capital Structure / Cost of Capital:

~~a.~~ 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, common and preferred equity, and shall use actual calendar year long term debt interest expenses, preferred dividends, and approved ROE. The long term debt balances and long term debt cost rate shall not include any amounts related to hedging activity.

~~b.~~ b. AEP shall use the most recent available FF1 actual end-of-year balances of outstanding long term debt (less the balance of any hedges), preferred equity, and common equity, in the projected ATRR used for billing purposes. 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) 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. However, any amortization of gains or losses on interest rate derivative hedging shall be excluded from long-term-debt cost annual and annualized expenses. AEP will reflect the calculation of its debt cost in Worksheets L and M.

~~c.~~ c. AEP is not restricted from hedging at its discretion, and all interest rate hedge gains and losses will be excluded from the formula rate for both the Projected and True-Up rates.

~~d.~~ d. AEP East Transmission Companies will establish LTD and Equity investments in the AEP East Transmission Companies as soon as is practicable (actual capital structure and long term debt costs and preferred equity costs). Until that time, the AEP East Transmission Companies will use the actual consolidated (weighted composite) capital structure and LTD cost rate of the AEP Operating Companies in PJM~~[1]~~ {The AEP Operating Companies in PJM are: Appalachian Power Company, Indiana Michigan Power Company, Kentucky Power Company, Kingsport Power Company, Ohio Power Company, and Wheeling Power Company} subject to a 50% equity ratio cap, as further explained

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~~[1] The AEP Operating Companies in PJM are: Appalachian Power Company, Indiana Michigan Power Company, Kentucky Power Company, Kingsport Power Company, Ohio Power Company, and Wheeling Power Company~~

below. Appendix A-1.1 to this Attachment A-1 describes the manner in which the weighted average composite capital structure and cost of long term debt and preferred equity costs of the AEP East Operating Companies in PJM shall be calculated.

~~e.~~ e. In transitioning from the use of the proxy composite capital cost of the East Operating Companies in PJM to an actual capital structure, long term debt cost and preferred equity cost, a transitioning East Transmission Company's actual capital structure and cost rates will be implemented for the Projected TCOS in the first formula rate Annual Update after the issuance of long-term debt or allocation of debt financing from an associated company establishing the transitioning East Company's actual capital structure and cost of debt. The True-Up TCOS in that Annual Update will continue to be based on the East Operating Companies' composite capital structure and LTD cost, and preferred equity costs.

~~f.~~ f. The first long term debt in the actual capital structure of an AEP Transmission Company is expected to be an allocation of proceeds from a debt issuance of AEP Transmission Company LLC or AEP Transmission Holding Company LLC (refer to page 7 of Exhibit AEP 100 for the AEPTCo Corporate Structure). The AEP Transmission Companies~~[2]~~- {The AEP Transmission Companies include the AEP East Transmission Companies and AEP Southwestern Transmission Company Inc., and AEP Oklahoma Transmission Co., Inc.} would draw debt financing from this issuance, as well as equity infusions from AEP Transmission Company LLC or AEP Transmission Holding Company LLC, based on their individual expenditure levels to establish their actual capital structure. The interest rate of this debt financing, along with any associated issuance costs incurred (not to include any costs related to any hedging activities), would define the initial cost of debt for the affected AEP Transmission Companies. This initial debt financing and all subsequent allocations of associated company (AEP Transmission Company LLC or AEP Transmission Holding Company LLC or a higher affiliate in AEP, Inc.) long term debt shall be recorded in Account 430 Advances from Associated Companies in the FERC Form No. 1 reports of the affected AEP Transmission Companies. However, long term debt issuances and equity of the AEP Operating Companies shall not be used to finance debt or equity in the actual

~~[2] The AEP Transmission Companies include the AEP East Transmission Companies and AEP Southwestern Transmission Company Inc., and AEP Oklahoma Transmission Co., Inc.~~

capital structure of the AEP Transmission Companies. The debt cost rate of long term debt issuances allocated from associated companies to the AEP Transmission Companies shall be at cost.

~~g.~~ g. In the event there is a construction draw down loan, the Companies will adopt the yield to maturity (YTM) approach filed in the PATH Settlement Agreement Docket No. ER08-386-000 in determining the cost of debt for such draw down loan[s], and illustrated in Attachment A.1.3. There is an annual and final (at end of loan) true-up of YTM, consistent with actual debt cost experience. Workpapers showing the calculation of the yield to maturity cost and true-up shall be included in the Annual Update(s) in which such charges are proposed to be included in the Projected rate.

~~h.~~ h. When an individual East Transmission Company has an actual capital structure, which is first achieved when the Transmission Company issues its own first long term debt issuance in its own name, or the individual Transmission Company has debt financing specifically allocated from an issuance by AEP Transmission Company LLC or AEP Transmission Holding Company LLC or a higher AEP corporate entity as described in (f) above, the actual long term debt cost and capital structure of that individual East Transmission Company shall be used in the Projected and True Up formula rates for that individual company, subject to a 50% Equity Ratio cap described below and subject to transition year treatment as described in (e) of this section. The True-up and Projected ATRR of the remaining East Transmission Companies which have not yet issued their own long term debt, or received a specific allocation of debt financing by an associated company for the purpose of rate making, shall continue to be based on the consolidated (composite) actual weighted average capital structure, long term debt cost, and preferred equity cost of all the East Operating Companies in PJM (including the costs of the operating company geographically associated with the individual transmission company which has established an actual capital structure and long-term debt cost).

~~i.~~ i. In applying the formula rate, the balance amounts of common equity, used in determining the weighted average cost of capital to be used for the AEP East Transmission Companies, shall not exceed 50% percent of the total projected and true-up capitalization ("Equity Cap"), regardless of the actual amounts of common equity capital outstanding. The Equity Cap applies to both the implementation of the consolidated East Operating Company's actual capital structure and to the implementation of an individual East Transmission Company actual capital structure. The Equity Cap can be removed or adjusted only after June 30, 2013 and only through a filing under section 205 or 206 of the Federal Power Act. When applied to the consolidated East Operating Companies' actual capital structure, the individual Operating Company equity caps pursuant to the East Operating Companies' settlement in Docket ER08-1329 shall be applied first before the 50% Equity Cap pursuant to the instant settlement is applied to the weighted composite East Operating Companies' capital structure. The composite weighted average long term debt cost rate of the East Operating Companies, exclusive of hedging costs and Indiana-Michigan Operating Company's spent nuclear fuel disposal funding costs, shall apply.

~~j.~~ j. If the percentage of common equity in the East Operating Companies' composite (consolidated) capitalization or any AEP East Transmission Company's actual 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.

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

~~1.~~ 1. If the AEP East Transmission 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.~~ 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.~~ F. Allocators.

~~1.~~ 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.~~ 2. No Account 565 costs other than inter-company charges that net out (such as lease arrangements and transmission equalization payments/receipts between AEP companies) will be included in the TCOS, unless first approved by FERC following a separate FPA § 205 filing by AEP.

~~3.~~ 3. AEP will include in the Annual Update to the formula rate, notification of any change in the use of established allocation factors (change from one factor to another established allocation factor for a cost applicable to AEP Transmission Companies). Any new allocation factor (not previously approved by the Securities and Exchange Commission or the FERC) will be filed with the FERC for approval in a Section 205 proceeding before being implemented, and AEP will provide notification in the Annual Update of the implementation of a newly created allocation factor that may affect costs allocated to the AEP Transmission Companies. In addition, AEP shall include notification in the Annual Updates of the establishment of any new regulated and un-regulated income-producing affiliates or operating divisions with new income-producing operations.

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.

III. Formula Implementation Protocols

The Formula Rate Implementation Protocols shall be adopted as set forth in Attachment A-2.

Appendix A-1.1

AEP East Consolidated Utility Capital Structure

Consolidation of Operating Companies' Capital Structure @ 12-31-2009

Worksheet Q Page 1

Line		Appalachian Power Company	Indiana Michigan Power Company	Kentucky Power Company	Kingsport Power Company	Ohio Power Company	Wheeling Power Company	AEP East Operating Companies' Consolidated Capital Structure
	Development of Long Term Debt Balances at Year End							
1	Bonds (112.18.c&d)	-	-	-	-	-	-	-
2	Less: Reacquired Bonds (112.19.c&d)	17,500,000	-	-	-	303,000,000	-	320,500,000
3	LT Advances from Assoc. Companies (112.20.c&d)	100,000,000	25,000,000	20,000,000	20,000,000	200,000,000	25,000,000	490,000,000
4	Senior Unsecured Notes (112.21.c&d) Excludes Spent Nuc Fuel Disp Fund	3,419,099,201	1,692,000,000	530,000,000	-	3,351,580,000	-	10,435,424,201
5	Less: Fair Value Hedges (See Note on Ln 7 below)	-	-	-	-	-	-	-
6	**Total Long Term Debt Balance**	3,501,599,201	1,717,000,000	550,000,000	20,000,000	3,248,580,000	25,000,000	10,604,924,201
7	NOTE: The balance of fair value hedges on outstanding long term debt are to be excluded from the balance of long term debt included in the formula's capital structure. (page 257, Column H of the FF1)							
	Development of Long Term Debt Interest Expense							
8	Interest on Long Term Debt (256-257.33.i)	201,508,637	100,346,371	30,323,070	1,075,000	129,578,994	1,312,500	547,990,827
9	Amort of Debt Discount & Expense (117.63.c)	3,232,592	3,157,632	457,098	-	3,354,846	-	12,043,656
10	Amort of Loss on Reacquired Debt (117.64.c)	991,540	1,596,824	33,649	-	626,793	-	3,992,302
11	Less: Amort of Premium on Debt (117.65.c)	-	-	-	-	-	-	-
12	Less: Amort of Gain on Reacquired Debt (117.66.c)	-	1,712	-	-	-	-	1,712
13	Less: Hedge Interest on pp 256-257(i)	2,569,395	1,551,518	92,956	-	(7,185,191)	-	(2,971,322)
14	**LTD Interest Expense**	203,163,374	103,547,597	30,720,861	1,075,000	140,745,824	1,312,500	566,996,395

Development of Cost of Preferred Stock and Preferred Dividends

15	Dividend Rate (p. 250-251. 7.a)	4.50%	4.125%			4.08%		
16	Par Value (p. 250-251. 8.c)	$ 100.00	$ 100.00			$ 100.00		
17	Shares Outstanding (p.250-251. 8.e)	177,518	55,301			14,595		
18	Monetary Value (Ln 16 * Ln 17)	17,751,800	5,530,100	-	-	1,459,500	-	24,741,400
19	Dividend Amount (Ln 15 * Ln 18)	798,831	228,117	-	-	59,548	-	1,086,495
20	Dividend Rate (p. 250-251. 7.a)		4.12%			4.20%		
21	Par Value (p. 250-251. 8.c)		$ 100.00			$ 100.00		
22	Shares Outstanding (p.250-251. 8.e)		11,055			22,824		
23	Monetary Value (Ln 21 * Ln 22)	-	1,105,500	-	-	2,282,400	-	3,387,900
24	Dividend Amount (Ln 20 * Ln 23)	-	45,547	-	-	95,861	-	141,407
25	Dividend Rate (p. 250-251. 7.a)		4.56%			4.40%		
26	Par Value (p. 250-251. 8.c)		$ 100.00			$ 100.00		
27	Shares Outstanding (p.250-251. 8.e)		14,412			31,482		
28	Monetary Value (Ln 26 * Ln 27)	-	1,441,200	-	-	3,148,200	-	4,589,400
29	Dividend Amount (Ln 25 * Ln 28)	-	65,719	-	-	138,521	-	204,240
30	Dividend Rate (p. 250-251. 7.a)					4.50%		
31	Par Value (p. 250-251. 8.c)					$ 100.00		
32	Shares Outstanding (p.250-251. 8.e)					97,363		
33	Monetary Value (Ln 31 * Ln 32)	-	-	-	-	9,736,300	-	9,736,300
34	Dividend Amount (Ln 30 * Ln 33)	-	-	-	-	438,134	-	438,134
35	**Preferred Stock (Lns 18, 23, 28,33)**	17,751,800	8,076,800	-	-	16,626,400	-	42,455,000
36	**Preferred Dividends (Lns 19, 24, 29,34)**	798,831	339,382	-	-	732,063	-	1,870,276
	Development of Common Equity							
37	Proprietary Capital (112.16.c)	2,789,329,067	1,680,859,984	431,783,697	21,335,470	3,251,321,953	43,904,852	9,578,370,175
38	Less: Preferred Stock (Ln 35 Above)	17,751,800	8,076,800	-	-	16,626,400	-	42,455,000
39	Less: Account 216.1 (112.12.c)	2,593,528	(581,331)	-	-	-	-	4,076,997
40	Less: Account 219.1 (112.15.c)	(50,254,363)				(118,458,118)	(1,749,500)	

Ln	Description							
			(21,700,504)	(600,942)	5,560			(242,751,398)
41	**Balance of Common Equity**	2,819,238,102	1,695,065,019	432,384,639	21,329,910	3,353,153,671	45,654,352	9,774,589,576
	Calculation of Capital Shares							
42	Long Term Debt (Ln 6 Above)	3,501,599,201	1,717,000,000	550,000,000	20,000,000	3,248,580,000	25,000,000	10,604,924,201
43	Preferred Stock (Ln 35 Above)	17,751,800	8,076,800	-	-	16,626,400	-	42,455,000
44	Common Equity (Ln 41 Above)	2,819,238,102	1,695,065,019	432,384,639	21,329,910	3,353,153,671	45,654,352	9,774,589,576
45	Total Company Structure	6,338,589,103	3,420,141,819	982,384,639	41,329,910	6,618,360,071	70,654,352	20,421,968,777
46	LTD Capital Shares (Ln 42 / Ln 45)	55.24%	50.20%	55.99%	48.39%	49.08%	35.38%	51.93%
47	Preferred Stock Capital Shares (Ln 43 / Ln 45)	0.28%	0.24%	0.00%	0.00%	0.25%	0.00%	0.21%
48	Common Equity Capital Shares (Ln 44 / Ln 45)	44.48%	49.56%	44.01%	51.61%	50.66%	64.62%	47.86%
49	**Equity Capital Share Limit**	50.00%	50.00%	50.00%	100.00%	51.00%	100.00%	50.00%
50	LTD Capital Shares with Capital Equity Cap	55.24%	50.20%	55.99%	48.39%	49.08%	35.38%	51.93%
51	Preferred Stock Capital Shares	0.28%	0.24%	0.00%	0.00%	0.25%	0.00%	0.21%
52	Common Equity Capital Shares with Capital Equity Cap	44.48%	49.56%	44.01%	51.61%	50.66%	64.62%	47.86%
	Calculation of Capital Cost Rate							
53	LTD Capital Cost Rate (Ln 14 / Ln 6)	5.80%	6.03%	5.59%	5.38%	4.33%	5.25%	5.35%
54	Preferred Stock Capital Cost Rate (Ln 36 / Ln 35)	4.50%	4.20%	0.00%	0.00%	4.40%	0.00%	4.41%
55	Common Equity Capital Cost Rate	11.49%	11.49%	11.49%	11.49%	11.49%	11.49%	11.49%
	Calculation of Weighted Capital Cost Rate							
56	LTD Weighted Capital Cost Rate (Ln 50 * Ln 53)	3.21%	3.03%	3.13%	2.60%	2.13%	1.86%	2.78%
57	Preferred Stock Capital Cost Rate (Ln 51 * Ln 54)	0.01%	0.01%	0.00%	0.00%	0.01%	0.00%	0.01%
58	Common Equity Capital Cost Rate (Ln 52 * Ln 55)	5.11%	5.69%	5.06%	5.93%	5.82%	7.42%	5.50%
59	**Total Company Structure**	**8.33%**	**8.73%**	**8.18%**	**8.53%**	**7.96%**	**9.28%**	**8.29%**

Appendix A-1.1

AEP East Consolidated Utility Capital Structure

Consolidation of Operating Companies' Capital Structure @ 12-31-2008

Worksheet Q Page 2

Line		Appalachian Power Company	Indiana Michigan Power Company	Kentucky Power Company	Kingsport Power Company	Ohio Power Company	Wheeling Power Company	AEP East Operating Companies' Consolidated Capital Structure
Development of Long Term Debt Balances at Year End								
60	Bonds (112.18.c&d)	-	-	-	-	-	-	-
61	Less: Reacquired Bonds (112.19.c&d)	17,500,000	100,000,000	-	-	85,000,000	-	294,745,000
62	LT Advances from Assoc. Companies (112.20.c&d)	100,000,000	-	20,000,000	20,000,000	200,000,000	25,000,000	465,000,000
63	Senior Unsecured Notes (112.21.c&d) Excludes Spent Nuc Fuel Disp Fund	3,114,740,790	1,217,000,000	400,000,000	-	2,594,450,000	-	8,768,935,790
64	Less: Fair Value Hedges (See Note on Ln 66 below)	-	-	-	-	-	-	-
65	**Total Long Term Debt Balance**	3,197,240,790	1,117,000,000	420,000,000	20,000,000	2,709,450,000	25,000,000	8,939,190,790

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

Line		Appalachian Power Company	Indiana Michigan Power Company	Kentucky Power Company	Kingsport Power Company	Ohio Power Company	Wheeling Power Company	AEP East Operating Companies' Consolidated Capital Structure
Development of Long Term Debt Interest Expense								
67	Interest on Long Term Debt (256-257.33.i)	181,193,862	69,755,551	26,429,625	1,075,000	134,040,796	1,312,500	491,905,445
68	Amort of Debt Discount & Expense (117.63.c)	2,539,613	2,467,181	451,645	-	2,211,243	-	8,755,819
69	Amort of Loss on Reacquired Debt (117.64.c)	1,440,062	2,142,335	33,648	-	1,618,264	-	5,991,748
70	Less: Amort of Premium on Debt (117.65.c)	-	-	-	-	-	-	-
71	Less: Amort of Gain on Reacquired Debt (117.66.c)	-	-	-	-	-	-	-
72	Less: Hedge Interest on pp 256-257(i)	5,001,679	1,547,947	92,956	-	(1,250,297)	-	5,392,285
73	**LTD Interest Expense**	180,171,858	72,817,120	26,821,962	1,075,000	139,120,600	1,312,500	501,260,727

Development of Cost of Preferred Stock and Preferred Dividends

74	Dividend Rate (p. 250-251. 7.a)	4.50%	4.125%			4.08%		
75	Par Value (p. 250-251. 8.c)	$ 100.00	$ 100.00			$ 100.00		
76	Shares Outstanding (p.250-251. 8.e)	177,520	55,335			14,595		
77	Monetary Value (Ln 75 * Ln 76)	17,752,000	5,533,500	-	-	1,459,500	-	24,745,000
78	Dividend Amount (Ln 74 * Ln 77)	798,840	228,257	-	-	59,548	-	1,086,644
79	Dividend Rate (p. 250-251. 7.a)		4.12%			4.20%		
80	Par Value (p. 250-251. 8.c)		$ 100.00			$ 100.00		
81	Shares Outstanding (p.250-251. 8.e)		11,055			22,824		
82	Monetary Value (Ln 80 * Ln 81)	-	1,105,500	-	-	2,282,400	-	3,387,900
83	Dividend Amount (Ln 79 * Ln 82)	-	45,547	-	-	95,861	-	141,407
84	Dividend Rate (p. 250-251. 7.a)		4.56%			4.40%		
85	Par Value (p. 250-251. 8.c)		$ 100.00			$ 100.00		
86	Shares Outstanding (p.250-251. 8.e)		14,412			31,482		
87	Monetary Value (Ln 85 * Ln 86)	-	1,441,200	-	-	3,148,200	-	4,589,400
88	Dividend Amount (Ln 84 * Ln 87)	-	65,719	-	-	138,521	-	204,240
89	Dividend Rate (p. 250-251. 7.a)					4.50%		
90	Par Value (p. 250-251. 8.c)					$ 100.00		
91	Shares Outstanding (p.250-251. 8.e)					97,373		
92	Monetary Value (Ln 90 * Ln 91)	-	-	-	-	9,737,300	-	9,737,300
93	Dividend Amount (Ln 89 * Ln 92)	-	-	-	-	438,179	-	438,179
94	**Preferred Stock (Lns 77, 82, 87,92)**	17,752,000	8,080,200	-	-	16,627,400	-	42,459,600
95	**Preferred Dividends (Lns 78, 83, 88,93)**	798,840	339,522	-	-	732,108	-	1,870,470

Development of Common Equity

96	Proprietary Capital (112.16.c)	2,394,342,663	1,444,357,731	398,008,673	25,031,105	2,438,571,961	37,950,872	7,987,702,880
97	Less: Preferred Stock (Ln 94 Above)	17,752,000	8,080,200	-	-	16,627,400	-	42,459,600

98	Less: Account 216.1 (112.12.c)	2,462,578	(1,510,668)	-	-	-	-	11,153,901
99	Less: Account 219.1 (112.15.c)	(60,225,378)	(20,233,842)	59,584	-	(133,858,575)	(2,464,181)	(263,573,252)
100	**Balance of Common Equity**	2,434,353,463	1,458,022,041	397,949,089	25,031,105	2,555,803,136	40,415,053	8,197,662,631
Calculation of Capital Shares								
101	Long Term Debt (Ln 65 Above)	3,197,240,790	1,117,000,000	420,000,000	20,000,000	2,709,450,000	25,000,000	8,939,190,790
102	Preferred Stock (Ln 94 Above)	17,752,000	8,080,200	-	-	16,627,400	-	42,459,600
103	Common Equity (Ln 100 Above)	2,434,353,463	1,458,022,041	397,949,089	25,031,105	2,555,803,136	40,415,053	8,197,662,631
104	Total Company Structure	5,649,346,253	2,583,102,241	817,949,089	45,031,105	5,281,880,536	65,415,053	17,179,313,021
105	LTD Capital Shares (Ln 101 / Ln 104)	56.59%	43.24%	51.35%	44.41%	51.30%	38.22%	52.03%
106	Preferred Stock Capital Shares (Ln 102 / Ln 104)	0.31%	0.31%	0.00%	0.00%	0.31%	0.00%	0.25%
107	Common Equity Capital Shares (Ln 103 / Ln 104)	43.09%	56.44%	48.65%	55.59%	48.39%	61.78%	47.72%
108	**Equity Capital Share Limit**	50.00%	50.00%	50.00%	100.00%	51.00%	100.00%	50.00%
109	LTD Capital Shares with Capital Equity Cap	56.59%	49.69%	51.35%	44.41%	51.30%	38.22%	53.00%
110	Preferred Stock Capital Shares	0.31%	0.31%	0.00%	0.00%	0.31%	0.00%	0.25%
111	Common Equity Capital Shares with Capital Equity Cap	43.09%	50.00%	48.65%	55.59%	48.39%	61.78%	46.75%
Calculation of Capital Cost Rate								
112	LTD Capital Cost Rate (Ln 73 / Ln 65)	5.64%	6.52%	6.39%	5.38%	5.13%	5.25%	5.61%
113	Preferred Stock Capital Cost Rate (Ln 95 / Ln 94)	4.50%	4.20%	0.00%	0.00%	4.40%	0.00%	4.41%
114	Common Equity Capital Cost Rate	11.49%	11.49%	11.49%	11.49%	11.49%	11.49%	11.49%
Calculation of Weighted Capital Cost Rate								
115	LTD Weighted Capital Cost Rate (Ln 109 * Ln 112)	3.19%	3.24%	3.28%	2.39%	2.63%	2.01%	2.97%
116	Preferred Stock Capital Cost Rate (Ln 110 * Ln 113)	0.01%	0.01%	0.00%	0.00%	0.01%	0.00%	0.01%
117	Common Equity Capital Cost Rate (Ln 111 * Ln 114)	4.95%	5.75%	5.59%	6.39%	5.56%	7.10%	5.37%
118	**Total Company Structure**	**8.15%**	**9.00%**	**8.87%**	**8.77%**	**8.21%**	**9.11%**	**8.35%**

Appendix A-1.1

AEP East Consolidated Utility Capital Structure

Consolidation of Operating Companies' Average Capital Structure

Worksheet Q Page 3

Line		Appalachian Power Company	Indiana Michigan Power Company	Kentucky Power Company	Kingsport Power Company	Ohio Power Company	Wheeling Power Company	AEP East Operating Companies' Consolidated Capital Structure
Development of Average Long Term Debt								
119	Average Bonds (Ln 1 + Ln 60) / 2	-	-	-	-	-	-	-
120	Less: Average Reacquired Bonds (Ln 2 + Ln 61) / 2	17,500,000	50,000,000	-	-	194,000,000	-	307,622,500
121	Average LT Advances from Assoc. Companies (Ln 3 + Ln 62) / 2	100,000,000	12,500,000	20,000,000	20,000,000	200,000,000	25,000,000	477,500,000
122	Average Senior Unsecured Notes (Ln 4 + Ln 63) / 2	3,266,919,996	1,454,500,000	465,000,000	-	2,973,015,000	-	9,602,179,996
123	Less: Average Fair Value Hedges (See Note on Ln 125 below)	-	-	-	-	-	-	-
124	**Average Balance of Long Term Debt**	3,349,419,996	1,417,000,000	485,000,000	20,000,000	2,979,015,000	25,000,000	9,772,057,496
125	NOTE: The balance of fair value hedges on outstanding long term debt are to be excluded from the balance of long term debt included in the formula's capital structure. (p. 257, Column H of the FF1)							
Development of 2009 Long Term Debt Interest Expense								
126	Interest on Long Term Debt (256-257.33.i)	201,508,637	100,346,371	30,323,070	1,075,000	129,578,994	1,312,500	547,990,827
127	Amort of Debt Discount & Expense (117.63.c)	3,232,592	3,157,632	457,098	-	3,354,846	-	12,043,656
128	Amort of Loss on Reacquired Debt (117.64.c)	991,540	1,596,824	33,649	-	626,793	-	3,992,302
129	Less: Amort of Premium on Debt (117.65.c)	-	-	-	-	-	-	-
130	Less: Amort of Gain on Reacquired Debt (117.66.c)	-	1,712	-	-	-	-	1,712

131	Less: Hedge Interest on pp 256-257(i)	2,569,395	1,551,518	92,956	-	(7,185,191)	-	(2,971,322)
132	**2009 LTD Interest Expense**	203,163,374	103,547,597	30,720,861	1,075,000	140,745,824	1,312,500	566,996,395
	2009 Cost of Preferred Stock and Preferred Dividends							
133	Average Balance of Preferred Stock (Ln 35 + Ln 94) / 2	17,751,900	8,078,500	-	-	16,626,900	-	42,457,300
134	2009 Preferred Dividends (Ln 36)	798,831	339,382	-	-	732,063	-	1,870,276
	Development of Average Common Equity							
135	Average Proprietary Capital (Ln 37 + Ln 96) / 2	2,591,835,865	1,562,608,858	414,896,185	23,183,288	2,844,946,957	40,927,862	8,783,036,528
136	Less: Average Preferred Stock (Ln 133 Above)	17,751,900	8,078,500	-	-	16,626,900	-	42,457,300
137	Less: Average Account 216.1 (Ln 39 + Ln 98) / 2	2,528,053	(1,046,000)	-	-	-	-	7,615,449
138	Less: Average Account 219.1 (Ln 40 + Ln 99) / 2	(55,239,871)	(20,967,173)	(270,679)	2,780	(126,158,347)	(2,106,841)	(253,162,325)
139	**Average Balance of Common Equity**	2,626,795,783	1,576,543,530	415,166,864	23,180,508	2,954,478,404	43,034,703	8,986,126,104
	Calculation of Capital Shares							
140	Average Balance of Long Term Debt (Ln 124 Above)	3,349,419,996	1,417,000,000	485,000,000	20,000,000	2,979,015,000	25,000,000	9,772,057,496
141	Average Balance of Preferred Stock (Ln 133 Above)	17,751,900	8,078,500	-	-	16,626,900	-	42,457,300
142	Average Balance of Common Equity (Ln 139 Above)	2,626,795,783	1,576,543,530	415,166,864	23,180,508	2,954,478,404	43,034,703	8,986,126,104
143	Average of Total Company Structure	5,993,967,678	3,001,622,030	900,166,864	43,180,508	5,950,120,304	68,034,703	18,800,640,899
144	Average Balance of LTD Capital Shares (Ln 140 / Ln 143)	55.88%	47.21%	53.88%	46.32%	50.07%	36.75%	51.98%
145	Average Balance of Preferred Stock Capital Shares (Ln 141 / Ln 143)	0.30%	0.27%	0.00%	0.00%	0.28%	0.00%	0.23%
146	Average Balance of Common Equity Capital Shares (Ln 142 / Ln 143)	43.82%	52.52%	46.12%	53.68%	49.65%	63.25%	47.80%
147	**Equity Capital Share Limit**	50.00%	50.00%	50.00%	100.00%	51.00%	100.00%	50.00%
148	LTD Capital Shares with Capital Equity Cap	55.88%	49.73%	53.88%	46.32%	50.07%	36.75%	52.38%
149	Preferred Stock Capital Shares	0.30%	0.27%	0.00%	0.00%	0.28%	0.00%	0.23%

150	Common Equity Capital Shares with Capital Equity Cap	43.82%	50.00%	46.12%	53.68%	49.65%	63.25%	47.39%
	Calculation of Capital Cost Rate							
151	LTD Capital Cost Rate (Ln 132 / Ln 124)	6.07%	7.31%	6.33%	5.38%	4.72%	5.25%	5.80%
152	Preferred Stock Capital Cost Rate (Ln 134 / Ln 133)	4.50%	4.20%	0.00%	0.00%	4.40%	0.00%	4.41%
153	Common Equity Capital Cost Rate	11.49%	11.49%	11.49%	11.49%	11.49%	11.49%	11.49%
	Calculation of Weighted Capital Cost Rate							
154	LTD Weighted Capital Cost Rate (Ln 148 * Ln 151)	3.39%	3.63%	3.41%	2.49%	2.37%	1.93%	3.04%
155	Preferred Stock Capital Cost Rate (Ln 149 * Ln 152)	0.01%	0.01%	0.00%	0.00%	0.01%	0.00%	0.01%
156	Common Equity Capital Cost Rate (Ln 150 * Ln 153)	5.04%	5.75%	5.30%	6.17%	5.71%	7.27%	5.45%
157	**ACTUAL WEIGHTED AVG COST OF CAPITAL**	**8.44%**	**9.39%**	**8.71%**	**8.66%**	**8.08%**	**9.20%**	**8.49%**

Appendix A.1.2

		AEP Appalachian Transmission Co	**AEP Indiana Michigan** Transmission Co	**AEP Kentucky** Transmission Co	**AEP Ohio** Transmission Co
350	Land Rights		~~1.16%~~1.27%	1.71%	~~1.44%~~1.49%
352	Structures & Improvements	1.55%	~~1.15%~~1.32%	1.71%	~~1.47%~~1.53%
353	Station Equipment	1.95%	~~1.46%~~1.69%	1.71%	~~1.71%~~1.78%
354	Towers & Fixtures	1.14%	~~1.46%~~1.60%	1.71%	~~1.44%~~1.48%
355	Poles & Fixtures	2.77%	~~2.19%~~2.43%	1.71%	~~2.22%~~2.30%
356	OH Conductors & Devices	1.01%	~~1.23%~~1.53%	1.71%	~~1.32%~~1.42%
357	Underground Conduit	1.23%	~~1.45%~~1.56%	1.71%	~~1.46%~~1.50%
358	Underground Conductor	3.18%	~~1.35%~~1.55%	1.71%	~~2.08%~~2.15%
3~~9~~59	Roads & Trails		~~1.50%~~1.49%	1.71%	~~1.61%~~1.60%

*For the states of Kentucky, West Virginia, Virginia, Indiana and Michigan, the formula rate will use rates based on the last approved depreciation study for the applicable jurisdiction (KPCo, APCo, or I&M). For example, rates for the 2004 I&M depreciation study will be used for Indiana and Michigan.

Ohio's rates are a composite rate calculated as the average of the APCo, I&M and KPCo rates. AEP's rates may only be changed in a Section 205/206 proceeding based on new studies. This filing may be a single issue proceeding.

Appendix A.1.3

Illustration of Construction Draw Down Loan

Appendix A.1.3 - Financing Costs for Long Term Debt using the Internal Rate of Return Methodology – AEP Transco

HYPOTHETICAL EXAMPLE

AEP Transco anticipates its financing will be a 7 year loan, where by AEP Transco pays Origination Fees of $7.9 million and a Commitments Fee of 0.375% on the undrawn principle.
Consistent with GAAP, AEP Transco will amortize the Origination Fees and Commitments Fees using the standard Internal Rate of Return formula below.
Each year, AEP Transco will true up the amounts withdrawn, the interest paid in the year, Origination Fees, Commitments Fees, and total loan amount on this attachment.

Total Loan Amount	**$ 600,000,000**

Internal Rate of Return[1]	**6.65%**
Based on following Financial Formula[2]:	
NPV = 0 =	

Origination Fees	
Underwriting Discount	-
Arrangement Fee	2,000,000
Upfront Fee	4,400,000
Rating Agency Fee	200,000
Legal Fees	1,250,000
Total Issuance Expense	**7,850,000**
Annual Rating Agency Fee	200,000
Annual Bank Agency Fee	75,000
Revolving Credit Commitment Fee	0.375%

	2008	2009	2010	2011	2012	2013	2014
LIBOR Rate	4.0610%	4.0610%	4.0610%	4.0610%	4.0610%	4.0610%	4.0610%
Spread	1.875%	1.875%	1.875%	1.875%	1.875%	1.875%	1.875%
Interest Rate	5.94%	5.94%	5.94%	5.94%	5.94%	5.94%	5.94%

(A) **Year**	(B)	(C) **Capital Expenditures ($000's)**	(D) **Principle Drawn In Quarter ($000's)**	(E) **Principle Drawn To Date ($000's)**	(F) **Interest Expense ($000's)**	(G) **Origination Fees ($000's)**	(H) **Commitment & Utilization Fee ($000's)**	(I) **Net Cash Flows ($000's)** **(D-F-G-H)**
Prior to 11/2008		16,529						
30/11/2008	Q4	8,923		-	-			-
15/02/2009	Q1	14,636	20,044	20,044	-	125		19,919
15/05/2009	Q2	17,119	8,560	28,604	297			8,262

15/08/2009	Q3	46,132	23,066	51,670	424			22,642
15/11/2009	Q4	62,740	31,370	83,040	767			30,603
15/02/2010	Q1	132,393	66,197	149,236	1,232	7,725	553	56,686
15/05/2010	Q2	132,393	66,197	215,433	2,215		491	63,490
15/08/2010	Q3	132,393	66,197	281,629	3,197		429	62,570
15/11/2010	Q4	132,393	66,197	347,826	4,179		367	61,650
15/02/2011	Q1	70,588	35,294	383,120	5,162		305	29,827
15/05/2011	Q2	70,588	35,294	418,414	5,685		272	29,336
15/08/2011	Q3	70,588	35,294	453,708	6,209		239	28,846
15/11/2011	Q4	70,588	35,294	489,002	6,733		206	28,355
15/022012	Q1	51,885	25,943	514,944	7,257		173	18,513
15/05/2012	Q2	51,885	25,943	540,887	7,642		148	18,152
15/08/2012	Q3	51,885	25,943	566,829	8,027		124	17,792
15/11/2012	Q4	51,885	25,943	592,772	8,412		100	17,431
15/02/2013	Q1	11,122	7,228	600,000	8,797		76	(1,644)
15/05/2013	Q2			600,000	8,904		69	(8,973)
15/08/2013	Q3			600,000	8,904		69	(8,973)
15/11/2013	Q4			600,000	8,904		69	(8,973)
15/02/2014	Q1			600,000	8,904		69	(8,973)
15/05/2014	Q2			600,000	8,904		69	(8,973)
15/08/2014	Q3			600,000	8,904		69	(8,973)
15/11/2014	Q4			600,000	8,904		69	(8,973)
15/02/2015	Q1			600,000	8,904		-	(608,903)

[1] The IRR is the Debt Cost shown on Page 5, Line 118 of Rate Formula Template.

[2] The IRR is a discount rate that makes the net present value of a series of cash flows equal to zero. The IRR equation can only be solved through iterations performed by a computer program (i.e.NPV function with goal seek in a spreadsheet program).

Appendix A.1.3

Hypothetical Example of Final True-Up of Interest Rates and Interest Calculations for the Construction Loan

To be Prepared on 8/15/2013 (hypothetical date)

SUMMARY

YEAR	Estimated Effective cost of debt used in forecast/true up	Final Effective cost of debt for the construction loan:	Hypothetical Revenue Requirement: Based on Estimated Effective cost of debt	Hypothetical Revenue Requirement: Based on Actual Effective cost of debt	Hypothetical Revenue Requirement: Over (Under) Recovery	Hypothetical Monthly Interest Rate applicable over the ATRR period	Total Amount of Construction Loan Related True-Up included in rates effective Jan 2014 (Refund)/Owed
2008	7.18%	7.00%	$ 2,500,000.00	$ 2,400,000.00	$ 100,000.00	0.550%	$ (148,288.33)
2009	6.8%	7.00%	$5,000,000.00	$5,150,000.00	$ (150,000.00)	0.560%	$ 209,670.43
2010	7.2%	7.00%	$8,300,000.00	$8,200,000.00	$ 100,000.00	0.540%	$ (131,109.09)
2011	7.3%	7.00%	$12,300,000.00	$12,000,000.00	$ 300,000.00	0.580%	$ (368,656.73)
2012*	7.1%	6.83%	$18,000,000.00	$17,900,000.00	$ 100,000.00	0.570%	$ (114,946.28)
2013**	6.50%	6.50%	$25,000,000.00	$25,000,000.00	$ -		
2014**	6.50%	6.50%					$ (553,329.99)

**** Assumes that the construction loan is retired on Sept 1, 2012***
***** Assumes permanent debt structure is put in place on Sept 1, 2012 with effective rate of 6.5%***
Note: True-Up period is 2008 - 2012, with the true-up amount included in 2014 forecasted ATRR. Final effective cost of debt for 2012 is computed as follows: ((7%*243days)+(6.5%*122days))/365days

Calculation of Applicable Interest Expense for each ATRR period

Interest Rate on Amount of Refunds or Surcharges from 35.19a		Over (Under) Recovery Plus Interest	Hypothetical Monthly Interest Rate	Months	Calculated Interest	Amortization	Surcharge (Refund) Owed
Calculation of Interest for 2008 True-Up Period							
An over or under collection will be recovered prorata over 2008, held for 2009, 2010, 2011, 2012, 2013 and returned prorate over 2014					**Monthly**		
January	Year 2008	-	0.5500%	12.00	-		-
February	Year 2008	-	0.5500%	11.00	-		-
March	Year 2008	10,000	0.5500%	10.00	(550)		(10,550)
April	Year 2008	10,000	0.5500%	9.00	(495)		(10,495)
May	Year 2008	10,000	0.5500%	8.00	(440)		(10,440)
June	Year 2008	10,000	0.5500%	7.00	(385)		(10,385)
July	Year 2008	10,000	0.5500%	6.00	(330)		(10,330)
August	Year 2008	10,000	0.5500%	5.00			(10,275)

					(275)		
September	Year 2008	10,000	0.5500%	4.00	(220)		(10,220)
October	Year 2008	10,000	0.5500%	3.00	(165)		(10,165)
November	Year 2008	10,000	0.5500%	2.00	(110)		(10,110)
December	Year 2008	10,000	0.5500%	1.00	(55)		(10,055)
					(3,025)		**(103,025)**
					Annual		
January through December	Year 2009	(103,025)	0.5600%	12.00	(6,923)		**(109,948)**
January through December	Year 2010	(109,948)	0.5400%	12.00	(7,125)		**(117,073)**
January through December	Year 2011	(117,073)	0.5800%	12.00	(8,148)		**(125,221)**
January through December	Year 2012	(125,221)	0.5700%	12.00	(8,565)		**(133,786)**
January through December	Year 2013	(133,786)	0.5700%	12.00	(9,151)		**(142,937)**
Over (Under) Recovery Plus Interest Amortized and Recovered Over 12 Months					**Monthly**		
January	Year 2014	**142,937**	0.5700%		(815)	(12,357)	(131,395)
February	Year 2014	131,395	0.5700%		(749)	(12,357)	(119,786)
March	Year 2014	119,786	0.5700%		(683)	(12,357)	(108,112)
April	Year 2014	108,112	0.5700%		(616)	(12,357)	(96,371)
May	Year 2014	96,371	0.5700%		(549)	(12,357)	(84,563)
June	Year 2014	84,563	0.5700%		(482)	(12,357)	(72,687)
July	Year 2014	72,687	0.5700%		(414)	(12,357)	(60,744)
August	Year 2014	60,744	0.5700%		(346)	(12,357)	(48,733)
September	Year 2014	48,733	0.5700%		(278)	(12,357)	(36,653)
October	Year 2014	36,653	0.5700%		(209)	(12,357)	(24,505)
November	Year 2014	24,505	0.5700%		(140)	(12,357)	(12,287)
December	Year 2014	12,287	0.5700%		(70)	(12,357)	0

		(5,351)
Total Amount of True-Up Adjustment for 2008 ATRR	$	(148,288)
Less Over (Under) Recovery	$	100,000
Total Interest	$	(48,288)

Appendix A.1.3

Hypothetical Example of Final True-Up of Interest Rates and Interest Calculations for the Construction Loan

Calculation of Interest for 2009 True-Up Period

An over or under collection will be recovered prorata over 2009, held for 2010, 2011, 2012, 2013 and returned prorate over 2014

					Monthly	
January	Year 2009	(12,500)	0.5600%	12.00	840	13,340
February	Year 2009	(12,500)	0.5600%	11.00	770	13,270
March	Year 2009	(12,500)	0.5600%	10.00	700	13,200
April	Year 2009	(12,500)	0.5600%	9.00	630	13,130
May	Year 2009	(12,500)	0.5600%	8.00	560	13,060
June	Year 2009	(12,500)	0.5600%	7.00	490	12,990
July	Year 2009	(12,500)	0.5600%	6.00	420	12,920
August	Year 2009	(12,500)	0.5600%	5.00	350	12,850
September	Year 2009	(12,500)	0.5600%	4.00	280	12,780
October	Year 2009	(12,500)	0.5600%	3.00	210	12,710
November	Year 2009	(12,500)	0.5600%	2.00	140	12,640
December	Year 2009	(12,500)	0.5600%	1.00	70	12,570
					5,460	**155,460**
					Annual	
January through December	Year 2010	155,460	0.5400%	12.00	10,074	**165,534**
January through December	Year 2011	165,534	0.5800%	12.00	11,521	**177,055**
January through December	Year 2012	177,055	0.5700%	12.00	12,111	**189,166**
January through December	Year 2013	189,166	0.5700%	12.00	12,939	**202,104**

Over (Under) Recovery Plus Interest Amortized and Recovered Over 12 Months				Monthly		
January	Year 2014	**(202,104)**	0.5700%	1,152	17,473	185,784
February	Year 2014	(185,784)	0.5700%	1,059	17,473	169,370
March	Year 2014	(169,370)	0.5700%	965	17,473	152,863
April	Year 2014	(152,863)	0.5700%	871	17,473	136,262
May	Year 2014	(136,262)	0.5700%	777	17,473	119,566
June	Year 2014	(119,566)	0.5700%	682	17,473	102,775
July	Year 2014	(102,775)	0.5700%	586	17,473	85,888
August	Year 2014	(85,888)	0.5700%	490	17,473	68,905
September	Year 2014	(68,905)	0.5700%	393	17,473	51,826
October	Year 2014	(51,826)	0.5700%	295	17,473	34,649
November	Year 2014	(34,649)	0.5700%	197	17,473	17,374
December	Year 2014	(17,374)	0.5700%	99	17,473	(0)
				7,566		
Total Amount of True-Up Adjustment for 2009 ATRR					$ 209,670	
Less Over (Under) Recovery					$ (150,000)	
Total Interest					$ 59,670	

Calculation of Interest for 2010 True-Up Period

An over or under collection will be recovered prorata over 2010, held for 2011, 2012, 2013 and returned prorate over 2014 **Monthly**

January	Year 2010	8,333	0.5400%	12.00	(540)	(8,873)
February	Year 2010	8,333	0.5400%	11.00	(495)	(8,828)
March	Year 2010	8,333	0.5400%	10.00	(450)	(8,783)
April	Year	8,333	0.5400%	9.00	(405)	(8,738)

	2010						
May	Year 2010	8,333	0.5400%	8.00	(360)		(8,693)
June	Year 2010	8,333	0.5400%	7.00	(315)		(8,648)
July	Year 2010	8,333	0.5400%	6.00	(270)		(8,603)
August	Year 2010	8,333	0.5400%	5.00	(225)		(8,558)
September	Year 2010	8,333	0.5400%	4.00	(180)		(8,513)
October	Year 2010	8,333	0.5400%	3.00	(135)		(8,468)
November	Year 2010	8,333	0.5400%	2.00	(90)		(8,423)
December	Year 2010	8,333	0.5400%	1.00	(45)		(8,378)
					(3,510)		**(103,510)**
					Annual		
January through December	Year 2011	(103,510)	0.5800%	12.00	(7,204)		**(110,714)**
January through December	Year 2012	(110,714)	0.5700%	12.00	(7,573)		**(118,287)**
January through December	Year 2013	(118,287)	0.5700%	12.00	(8,091)		**(126,378)**
Over (Under) Recovery Plus Interest Amortized and Recovered Over 12 Months					**Monthly**		
January	Year 2014	**126,378**	0.5700%		(720)	(10,926)	(116,173)
February	Year 2014	116,173	0.5700%		(662)	(10,926)	(105,909)
March	Year 2014	105,909	0.5700%		(604)	(10,926)	(95,587)
April	Year 2014	95,587	0.5700%		(545)	(10,926)	(85,206)
May	Year 2014	85,206	0.5700%		(486)	(10,926)	(74,766)
June	Year 2014	74,766	0.5700%		(426)	(10,926)	(64,266)
July	Year 2014	64,266	0.5700%		(366)	(10,926)	(53,707)
August	Year 2014	53,707	0.5700%		(306)	(10,926)	(43,087)
September	Year 2014	43,087	0.5700%		(246)	(10,926)	(32,407)
October	Year 2014	32,407	0.5700%		(185)	(10,926)	(21,666)
November	Year 2014	21,666	0.5700%		(123)	(10,926)	(10,864)
December	Year 2014	10,864	0.5700%		(62)	(10,926)	0
					(4,731)		
Total Amount of True-Up Adjustment for 2010 ATRR						$ (131,109)	
Less Over (Under) Recovery						$ 100,000	
Total Interest							$ (31,109)

Appendix A.1.3

Hypothetical Example of Final True-Up of Interest Rates and Interest Calculations for the Construction Loan

Calculation of Interest for 2011 True-Up Period

An over or under collection will be recovered prorata over 2011, held for 2012, 2013 and returned prorate over 2014

						Monthly		
January	Year 2011		25,000	0.5800%	12.00	(1,740)		(26,740)
February	Year 2011		25,000	0.5800%	11.00	(1,595)		(26,595)
March	Year 2011		25,000	0.5800%	10.00	(1,450)		(26,450)
April	Year 2011		25,000	0.5800%	9.00	(1,305)		(26,305)
May	Year 2011		25,000	0.5800%	8.00	(1,160)		(26,160)
June	Year 2011		25,000	0.5800%	7.00	(1,015)		(26,015)
July	Year 2011		25,000	0.5800%	6.00	(870)		(25,870)
August	Year 2011		25,000	0.5800%	5.00	(725)		(25,725)
September	Year 2011		25,000	0.5800%	4.00	(580)		(25,580)
October	Year 2011		25,000	0.5800%	3.00	(435)		(25,435)
November	Year 2011		25,000	0.5800%	2.00	(290)		(25,290)
December	Year 2011		25,000	0.5800%	1.00	(145)		(25,145)
						(11,310)		**(311,310)**
						Annual		
January through December	Year 2012	(311,310)		0.5700%	12.00	(21,294)		**(332,604)**
January through December	Year 2013	(332,604)		0.5700%	12.00	(22,750)		**(355,354)**
Over (Under) Recovery Plus Interest Amortized and Recovered Over 12 Months						**Monthly**		
January	Year 2014	**355,354**		0.5700%		(2,026)	(30,721)	(326,658)
February	Year 2014	326,658		0.5700%		(1,862)	(30,721)	(297,798)
March	Year 2014	297,798		0.5700%			(30,721)	(268,774)

				(1,697)		
April	Year 2014	268,774	0.5700%		(30,721)	(239,585)
				(1,532)		
May	Year 2014	239,585	0.5700%		(30,721)	(210,229)
				(1,366)		
June	Year 2014	210,229	0.5700%		(30,721)	(180,706)
				(1,198)		
July	Year 2014	180,706	0.5700%		(30,721)	(151,015)
				(1,030)		
August	Year 2014	151,015	0.5700%		(30,721)	(121,154)
				(861)		
September	Year 2014	121,154	0.5700%		(30,721)	(91,123)
				(691)		
October	Year 2014	91,123	0.5700%		(30,721)	(60,921)
				(519)		
November	Year 2014	60,921	0.5700%		(30,721)	(30,547)
				(347)		
December	Year 2014	30,547	0.5700%	(174)	(30,721)	0
						(13,303)
Total Amount of True-Up Adjustment for 2011 ATRR			$ (368,657)			
Less Over (Under) Recovery			$ 300,000			
Total Interest			$ (68,657)			

Calculation of Interest for 2012 True-Up Period						
An over or under collection will be recovered prorata over 2012, held for 2013 and returned prorate over 2014			**Monthly**			
January	Year 2012		0.5700%	12.00	(570)	(8,903)
		8,333				
February	Year 2012		0.5700%	11.00	(523)	
		8,333				(8,856)
March	Year 2012		0.5700%	10.00	(475)	
		8,333				(8,808)
April	Year 2012		0.5700%	9.00	(428)	
		8,333				(8,761)
May	Year 2012		0.5700%	8.00	(380)	
		8,333				(8,713)
June	Year 2012		0.5700%	7.00	(333)	
		8,333				(8,666)
July	Year 2012		0.5700%	6.00	(285)	
		8,333				(8,618)
August	Year 2012		0.5700%	5.00	(238)	
		8,333				(8,571)

September	Year 2012	8,333	0.5700%	4.00	(190)		(8,523)
October	Year 2012	8,333	0.5700%	3.00	(143)		(8,476)
November	Year 2012	8,333	0.5700%	2.00	(95)		(8,428)
December	Year 2012	8,333	0.5700%	1.00	(48)		(8,381)
					(3,705)		**(103,705)**
					Annual		
January through December	Year 2013	(103,705)	0.5700%	12.00	(7,093)	**(110,798)**	

Over (Under) Recovery Plus Interest Amortized and Recovered Over 12 Months				**Monthly**		
January	Year 2014	**110,798**	0.5700%	(632)	(9,579)	(101,851)
February	Year 2014	101,851	0.5700%	(581)	(9,579)	(92,853)
March	Year 2014	92,853	0.5700%	(529)	(9,579)	(83,803)
April	Year 2014	83,803	0.5700%	(478)	(9,579)	(74,702)
May	Year 2014	74,702	0.5700%	(426)	(9,579)	(65,549)
June	Year 2014	65,549	0.5700%	(374)	(9,579)	(56,344)
July	Year 2014	56,344	0.5700%	(321)	(9,579)	(47,086)
August	Year 2014	47,086	0.5700%	(268)	(9,579)	(37,776)
September	Year 2014	37,776	0.5700%	(215)	(9,579)	(28,412)
October	Year 2014	28,412	0.5700%	(162)	(9,579)	(18,995)
November	Year 2014	18,995	0.5700%	(108)	(9,579)	(9,525)
December	Year 2014	9,525	0.5700%	(54)	(9,579)	0
				(4,148)		

Total Amount of True-Up Adjustment for 2012 ATRR	$ (114,946)
Less Over (Under) Recovery	$ 100,000
Total Interest	$ (14,946)