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AEP.com

February 26, 2014

Honorable Kimberly D. Bose, Secretary
Federal Energy Regulatory Commission
888 First Street, N.E., Room 1A
Washington, D.C. 20426

Re: American Electric Power Service Corporation
Docket No. ER14-1375-000

Dear Secretary Bose:

Pursuant to Section 205 of the Federal Power Act, 16 U.S.C. Section 824(d), and Section 35.13 of the Federal Energy Regulatory Commission's ("FERC" or "Commission") regulations, American Electric Power Service Corporation ("AEPSC"), on behalf of its affiliates, Appalachian Power Company, Indiana Michigan Power Company, Kentucky Power Company, Kingsport Power Company, Ohio Power Company, and Wheeling Power Company (together, "AEP East Operating Companies"),[1] submits for filing revisions to the formula rate of the AEP East Operating Companies, Attachment H-14 of the PJM Interconnection, L.L.C. ("PJM") Open Access Transmission Tariff ("PJM Tariff") to update the base Post-employment Benefits Other than Pensions ("PBOP") expense as contemplated in the formula rate settlement approved by the Commission ("Attachment H-14 Settlement").[2]

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.[3] AEP and the intervening parties in Docket No. ER08-1329 ultimately settled all issues raised with respect to the formula rate, and the Commission approved the Attachment H-14 Settlement on October 1, 2010.[4]

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1 AEPSC and the AEP East Operating Companies are collectively referred to as "AEP."

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

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

4 *See* n.2.

The principles of the Attachment H-14 Settlement are incorporated into the PJM Tariff as Appendix A to Attachment H-14A. Section I.C.6 provides that, during the annual update process conducted in 2013 (and every four years thereafter), AEP will undergo a review of PBOP costs and submit a single issue filing under Section 205 of the FPA to update the PBOP expense in the formula rate provided certain thresholds are met. In particular, Section I.C.6.iii provides:

> During the annual update process conducted in 2013, and every four years thereafter, Worksheet O will be used to determine whether, and if so by what amount, the PBOP allowance should be adjusted going forward for the next four years. If the Annual Actuarial Report produced for that year projects PBOP costs during the next four years, taken together with the then current cumulative PBOP cost/allowance position, will, absent a change in the PBOP allowance, cause the AEP Companies to over or under collect their cumulative PBOP costs by more than 20% of the projected next four year's total cost, the PBOP allowance shall be adjusted.

Section I.C.6.iii proceeds to describe the methodology for calculating the percentage of over or under collection, explaining:

> In order to determine whether the AEP Companies' cumulative allowance of PBOP costs under the formula rate will result in a cumulative over or under-recovery of actual PBOP expenses exceeding 20% over the subsequent four year period, Worksheet O will be used to determine the following PBOB cost/allowance values:
>
> > (a) the level of cumulative over or under collections during the period since the PBOP allowance was last set, including carrying costs based on the weighted average cost of capital ("WACC") each year from the Formula rate True-Up transmission cost-of-service ("TCOS") analyses;
> >
> > (b) the cumulative net present value ("CNPV") of projected PBOP costs during the next four years, as estimated by the then current Actuarial Report, assuming a discount rate equal to the True-Up TCOS WACC for the prior calendar year ("Prior Year WACC"); and
> >
> > (c) the CNPV of continued collections over the next four years based on the then effective PBOP allowance, assuming a discount rate equal to the Prior Year WACC.
>
> If the absolute value of (a) + (b) - (c) exceeds 20% of (b), then the PBOP allowance used in the formula rate calculation shall be changed to the value that will cause the projected result of (a) + (b) - (c) to equal zero. If the projected over or under collection during the next four years, (a) + (b) - (c), will be less than 20% of (b), then the PBOP Allowance will continue in effect for the next four years at the then effective rate.

Section I.6.C.iii further prescribes next steps in the event the calculation results in an over or under-recovery of more than 20%, explaining:

> If it is determined through the foregoing procedure that the AEP Companies' cumulative PBOP expense allowance will over-recover or under-recover actual PBOP expenses by more than 20% over the subsequent four-year period, AEP shall make a filing under FPA § 205 to change the PBOP expense stated in the formula rate. No other changes to the formula rate may be included in that filing. Neither AEP nor any Settling Party may raise in connection with such filing any issue affecting the formula rate other than the level of allowable PBOP expense.

II. Description of Proposed Changes

Consistent with the requirements of the Attachment H-14 Settlement, AEP conducted a review of its PBOP costs and determined that the current expense allowance will cause the AEP East Operating Companies to over collect their cumulative PBOP costs by more than 20% of the projected next four years' total cost. In particular, as shown in the analysis attached as Attachment A to this filing, the current PBOP allowance contained in Attachment H-14 ($48.1 million) will exceed the 20% threshold, with an over recovery 58% greater than the projected amount supported by current actuarial projections.

Consequently, through this single issue Section 205 filing, AEP seeks an adjustment to the PBOP expense allowance provided in Attachment H-14 to decrease the base PBOP expense to approximately $30 million. Although the difference between the current PBOP allowance contained in Attachment H-14 of $48.1 million and the revised amount of $30 million is $18.1 million, the effect on the revenue requirement will be a fraction of that amount – a decrease of approximately $1,000,000. This is because AEP uses an allocator methodology to assign recoverable PBOP expenses among the various AEP affiliates.

III. Effective Date and Waiver Request

As contemplated in the principles of the Attachment H-14 Settlement, AEP seeks an effective date of July 1, 2014 of the proposed changes to update the PBOP expense allowance as described herein. AEP respectfully requests that the Commission waive provisions of section 35.13 or any other applicable regulation to the extent necessary to permit this request.

While implementation of AEP's request will result in an overall decrease in the revenue requirement, AEP notes that the process and criteria for revising the PBOP expense allowance was an agreed-upon aspect of the Attachment H-14 Settlement. Therefore, the request in this filing relates to the implementation of the formula rate as originally approved and is not a change to the design of the formula rate itself.

IV. Contents of this Filing

This filing consists of the following documents:

a. This transmittal letter;
b. A spreadsheet setting forth the calculation of the change in the PBOP expense (Attachment A);
c. A marked version of Attachment H-14B (Attachment B); and
d. A clean version of Attachment H-14B (Attachment C).

Pursuant to Section 35.7 of the Commission's regulations,[5] the contents of this filing are being submitted as part of an XML filing package that conforms to the Commission's eTariff instructions.

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,[6] 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[7] 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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5 Pursuant to Order No. 714, this filing is submitted by PJM on behalf of AEPSC as part of an XML filing package that conforms to 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 in the eTariff system as part of PJM's electronic Intra PJM Tariff.

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

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

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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 grant any applicable waivers.

Respectfully submitted,

/s/ Amanda R. Conner

Amanda R. Conner
Senior Counsel
American Electric Power Service Corporation

Enclosures

ATTACHMENT A

Calculation of the change in the PBOP expense recovered through the Annual Transmission Formula Rates for AEP East Operating Companies For Network Integration Transmission Service Included as Attachment H-14B to the PJM Open Access Transmission Tariff

AEP East Companies
Cost of Service Formula Rate
Calculation of Over/Under Recovery of Other Post Employment Benefits

Line#

Section 1) Calculation of Projected Recovery Position On Total Company Basis

A. Summary of All Companies' OPEB Actual Vs. Allowance

Line	Year	Source	OPEB Basis per Actuarial Report	Settlement OPEB Basis	OPEB Functionalized To Transmission	Settlement OPEB Functionalized to Transmission	Under / (Over) Recovery	Annual Expense (Over)/Under	Prior Year Cumulative (Over)/Under	Carrying Charge on Cumulative Expense (Over)/Under	Cumulative Expense (Over)/Under @ Year End
		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)
1	**2009**	**Line 24**	63,029,938	48,100,000	3,882,678	2,962,986	919,692	919,692	-	39,094	958,786
2	**2010**	**Line 42**	50,269,091	48,100,000	3,600,497	3,445,137	155,360	155,360	958,786	88,250	1,202,396
3	**2011**	**Line 49**	28,202,753	48,100,000	1,534,401	2,616,932	(1,082,531)	(1,082,531)	1,202,396	55,917	175,783
4	**2012**	**Line 56**	40,891,187	48,100,000	2,617,422	3,078,853	(461,432)	(461,432)	175,783	(5,290)	**(290,939)**
5	**Sum of Lines 1 to 4**		182,392,969	192,400,000	11,634,997	12,103,908					

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B. Net Present Values of Future OPEB Expense and Current Allowance

Line	Year	Total Company Amount		Functionalized Amount	
		OPEB Basis per Actuarial Report	**Settlement OPEB Basis**	**OPEB Functionalized To Transmission (NOTE 1)**	**Settlement OPEB Functionalized to Transmission (NOTE 2)**
6	**2013**	36,449,906	30,000,000	2,275,197	1,887,304
7	**2014**	32,635,533	30,000,000	2,029,548	1,887,304
8	**2015**	29,535,002	30,000,000	1,829,607	1,887,304
9	**2016**	27,461,419	30,000,000	1,695,132	1,887,304
10	**Sum of Lines 6 to 9**	126,081,859	120,000,000	7,829,485	7,549,215

NOTE 1: The OPEB Actuarial Projection is functionalized based on the average company labor allocators from the four year recovery period

NOTE 2: The OPEB Settlement amount for each year of the projected four year period is the projected settlement amount times the sum of the historic functionalized settlement amount divided by the sum of the historic four year total settlement amount. I.E 30000000 * (12103908/192400000).

11	Prior Year WACC From True-Up	+k114	8.55%	8.55%	
12	Functionalized Cumulative Net Present Values of Lines 6 Through 9		6,469,123	6,174,579	
13	NPV of (Over) / Under Collection Projected for 2013 Through 2016				294,544
14	Cumulative Four Year (Over) / Under Collection From Line 5, Col. (J)		8.47%		**(290,939)**
15	Net Projected (Over) / Under Allowance in Four Years	Ln 13 + Ln 14			3,605
16	**Projected Cumulative Balance As as a Percent of the Net Present Value of the Four Year Projected OPEB Expense**				**0.056%** <==NOTE 3

NOTE 3: If the absolute value of this amount is greater than 20% of the cumulative net present value of the sum of the projected functionalized OPEB expense, the OPEB allowance will need to be revised via a 205 Filing per the FERC.

AEP East Companies
Cost of Service Formula Rate
Calculation of Over/Under Recovery of Other Post Employment Benefits

Line#
Section 2) Calculation of Annual (Over) / Under Recovery by Total Company and Functional Transmission

Allocation of OPEB Settlement for 2009:

Line#	Company	Actual Expense (Including AEPSC Billed OPEB	Total Company Amount Ratio of Company Actual to Total	Allocation of PBOB Recovery Allowance	Labor Allocator	Avoided Expense	Recoverable Expense	Annual Functional Expense (Over)/Under	Prior Year Cumulative Functional (Over)/Under Recovery	Company WACC	Carrying Charge on Cumulative (Over)/Under	Cumulative (Over)/Under Recovery @ Year End
		(A)	(B)=(A)/Total (A)	(C)=(B) * 48100000	(D)	(E)=(A) * (D)	(F)=(C) * (D)	(G)=(E) - (F)	(H)	(I)	(J) = ((G)/2 + (H)) * (I)	(K) = (G) + (H) + (J)
17	APCo	18,441,517	29.26%	14,073,264	7.028%	1,296,063	989,064	306,999	-	8.48%	13,017	320,016
18	CSP	10,281,860	16.31%	7,846,390	4.162%	427,913	326,553	101,360	-	8.48%	4,298	105,658
19	I&M	12,473,804	19.79%	9,519,127	4.127%	514,802	392,861	121,941	-	9.44%	5,756	127,697
20	KPCo	3,529,520	5.60%	2,693,481	8.595%	303,351	231,496	71,855	-	8.72%	3,133	74,988
21	KNGP	544,295	0.86%	415,368	11.148%	60,678	46,305	14,373	-	8.66%	622	14,995
22	OPCo	17,102,723	27.13%	13,051,591	7.326%	1,252,955	956,167	296,788	-	8.07%	11,975	308,764
23	WPCo	656,219	1.04%	500,780	4.102%	26,916	20,540	6,376	-	9.20%	293	6,669
24	**Sum of Lines 17 to 23**	63,029,938		48,100,000		3,882,678	2,962,986	919,692	-		39,094	958,786

Allocation of OPEB Settlment for 2010:

Line#	Company	Actual Expense (Including AEPSC Billed OPEB	Total Company Amount Ratio of Company Actual to Total	Allocation of PBOB Recovery Allowance	Labor Allocator	Avoided Expense	Recoverable Expense	Annual Functional Expense (Over)/Under	Prior Year Cumulative Functional (Over)/Under Recovery	Company WACC	Carrying Charge on Cumulative (Over)/Under	Cumulative (Over)/Under Recovery @ Year End
		(A)	(B)=(A)/Total (A)	(C)=(B) * 48100000	(D)	(E)=(A) * (D)	(F)=(C) * (D)	(G)=(E) - (F)	(H)	(I)	(J) = ((G)/2 + (H)) * (I)	(K) = (G) + (H) + (J)
35	APCo	13,207,032	26.27%	12,637,154	7.489%	989,110	946,430	42,680	320,016	8.35%	28,503	391,199
36	CSP	7,759,634	15.44%	7,424,809	5.961%	462,523	442,566	19,958	105,658	8.60%	9,945	135,560
37	I&M	13,602,157	27.06%	13,015,229	5.208%	708,440	677,871	30,569	127,697	8.95%	12,797	171,063
38	KPCo	2,592,157	5.16%	2,480,306	9.956%	258,066	246,930	11,135	74,988	8.70%	7,008	93,131
39	KNGP	386,298	0.77%	369,629	8.357%	32,284	30,891	1,393	14,995	7.33%	1,150	17,538
40	OPCo	12,241,700	24.35%	11,713,476	9.182%	1,123,972	1,075,473	48,499	308,764	8.46%	28,173	385,435
41	WPCo	480,113	0.96%	459,396	5.436%	26,101	24,975	1,126	6,669	9.32%	674	8,469
42	**Sum of Lines 35 to 41**	50,269,091		48,100,000		3,600,497	3,445,137	155,360	958,786		88,250	1,202,396

Allocation of OPEB Settlment for 2011:

Line#	Company	Actual Expense (Including AEPSC Billed OPEB	Total Company Amount Ratio of Company Actual to Total	Allocation of PBOB Recovery Allowance	Labor Allocator	Avoided Expense	Recoverable Expense	Annual Functional Expense (Over)/Under	Prior Year Cumulative Functional (Over)/Under Recovery	Company WACC	Carrying Charge on Cumulative (Over)/Under	Cumulative (Over)/Under Recovery @ Year End
		(A)	(B)=(A)/Total (A)	(C)=(B) * 48100000	(D)	(E)=(A) * (D)	(F)=(C) * (D)	(G)=(E) - (F)	(H)	(I)	(J) = ((G)/2 + (H)) * (I)	(K) = (G) + (H) + (J)
43	APCo	7,091,350	25.14%	12,094,349	6.501%	461,017	786,268	(325,251)	391,199	8.27%	18,903	84,851
44	I&M	9,877,771	35.02%	16,846,610	3.613%	356,849	608,608	(251,760)	171,063	8.83%	3,990	(76,707)
45	KPCo	1,688,311	5.99%	2,879,427	8.051%	135,929	231,829	(95,899)	93,131	8.74%	3,949	1,181
46	KNGP	213,130	0.76%	363,495	11.519%	24,551	41,872	(17,321)	17,538	8.62%	765	983
47	OPCo	9,085,422	32.21%	15,495,253	6.002%	545,299	930,011	(384,712)	520,996	8.48%	27,869	164,152
48	WPCo	246,769	0.87%	420,866	4.359%	10,756	18,345	(7,589)	8,469	9.45%	442	1,322
49	**Sum of Lines 43 to 48**	28,202,753		48,100,000		1,534,401	2,616,932	(1,082,531)	1,202,396		55,917	175,783

Allocation of OPEB Settlment for 2012:

Line#	Company	Actual Expense (Including AEPSC Billed OPEB	Total Company Amount Ratio of Company Actual to Total	Allocation of PBOB Recovery Allowance	Labor Allocator	Avoided Expense	Recoverable Expense	Annual Functional Expense (Over)/Under	Prior Year Cumulative Functional (Over)/Under Recovery	Company WACC	Carrying Charge on Cumulative (Over)/Under	Cumulative (Over)/Under Recovery @ Year End
		(A)	(B)=(A)/Total (A)	(C)=(B) * 48100000	(D)	(E)=(A) * (D)	(F)=(C) * (D)	(G)=(E) - (F)	(H)	(I)	(J) = ((G)/2 + (H)) * (I)	(K) = (G) + (H) + (J)
50	APCo	11,359,793	27.78%	13,362,440	7.081%	804,397	946,207	(141,809)	84,851	8.10%	1,130	(55,828)
51	I&M	10,586,657	25.89%	12,453,006	4.206%	445,250	523,744	(78,494)	(76,707)	8.96%	(10,389)	(165,591)
52	KPCo	2,188,039	5.35%	2,573,774	9.694%	212,116	249,511	(37,394)	1,181	8.78%	(1,538)	(37,751)
53	KNGP	277,875	0.68%	326,862	13.137%	36,506	42,941	(6,436)	983	8.69%	(194)	(5,647)
54	OPCo	16,164,303	39.53%	19,013,950	6.771%	1,094,477	1,287,425	(192,948)	164,152	8.55%	5,786	(23,010)
55	WPCo	314,520	0.77%	369,968	7.846%	24,676	29,026	(4,350)	1,322	9.89%	(84)	(3,112)
56	**Sum of Lines 50 to 55**	40,891,187		48,100,000		2,617,422	3,078,853	(461,432)	175,783	8.555%	(5,290)	(290,939)

AEP East Companies
Cost of Service Formula Rate
Calculation of Over/Under Recovery of Other Post Employment Benefits

Line#

Section 3) PBOP Charges Per Actuarial Report By Company For Four Year Projected Period

		Total Company					Functionalized to Transmission			
		(A)	(B)	(C)	(D)	(E)				
	Company	2013	2014	2015	2016	Average Labor	2013	2014	2015	2016
57	APCo	10,705,930	9,454,654	8,433,056	7,737,727	7.025%	752,077	664,176	592,410	543,564
58	I&M	9,867,406	9,136,839	8,549,767	8,183,928	4.288%	423,158	391,828	366,652	350,963
59	KPCo	1,971,261	1,762,585	1,588,648	1,468,929	9.074%	178,871	159,936	144,153	133,290
60	KNGP	246,719	218,984	196,815	181,709	11.040%	27,239	24,177	21,729	20,062
61	OPCo	13,382,202	11,821,252	10,554,265	9,696,424	6.567%	878,829	776,319	693,114	636,778
62	WPCo	276,389	241,218	212,450	192,701	5.436%	15,024	13,112	11,548	10,475
63	**Sum of Lines 57 to 62**	36,449,906	32,635,533	29,535,002	27,461,419		2,275,197	2,029,548	1,829,607	1,695,132

	2012	2013	2014	2015	2016
APCo	1,038,300	976,660	916,922	869,547	841,981
I&M	795,128	747,924	702,177	665,897	644,787
KPCo	193,112	181,648	170,537	161,726	156,599
KNGP	30,141	28,352	26,617	25,242	24,442
OPCo	1,430,998	1,346,045	1,263,713	1,198,421	1,160,429
WPCo	32,337	30,417	28,557	27,081	26,223
Total	3,520,016	3,311,045	3,108,524	2,947,915	2,854,462
Actuarial Report	19,898,209	18,716,921	17,572,096	16,664,191	16,135,913
2012 based on books records					

ATTACHMENT B

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 NOTE 1	(C) Property	(D) Labor	(E) Other	(F) Non-Allocable
1	**Revenue Taxes**					
2	List Individual Taxes Here	-				-
3	**Real Estate and Personal Property Taxes**					
4	Real and Personal Property - Jurisdiction #1	-	-			
5	Real and Personal Property - Jurisdiction #2	-	-			
6	Real and Personal Property - Jurisdiction #3	-	-			
7	Real and Personal Property - Other Jurisdictions	-	-			
8	**Payroll Taxes**					
9	Federal Insurance Contribution (FICA)	-		-		
10	Federal Unemployment Tax	-		-		
11	State Unemployment Insurance	-		-		
12	**Production Taxes**					
13	List Individual Taxes Here	-				-
14		-				-
15	**Miscellaneous Taxes**					
16	List Individual Taxes Here	-				-
17		-			-	
18		-			-	
19		-			-	
20		-			-	
21		-				-
22		-				-
23		-				-
24	Total Taxes by Allocable Basis	-	-	-	-	-

(Total Company Amount Ties to FFI p.114, Ln 14,(c))
NOTE 1: The detail of each total company number and its source in the FERC Form 1 is shown on WS H-1.

Functional Property Tax Allocation

Line No.		Production	Transmsission	Distribution	General	Total
25	Functionalized Net Plant (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

		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)

Project Description:

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

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

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

CUMULATIVE HISTORY OF PROJECTED ANNUAL REVENUE REQUIREMENTS:

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

RTEP Projected Rev. Req't.From Prior Year Template w/o Incentives		**RTEP Projected Rev. Req't.From Prior Year Template with Incentives ****		

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

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

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

AEP East Companies
Cost of Service Formula Rate Using 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	-

TRUE UP OF PROJECT REVENUE REQUIREMENT FOR PRIOR YEAR:

CUMULATIVE HISTORY OF TRUED-UP ANNUAL REVENUE REQUIREMENTS:

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

Investment Year	Beginning Balance	Depreciation Expense	Ending Balance	Average Balance	RTEP Rev. Req't. w/o Incentives	RTEP Rev. Req't. with Incentives **	Incentive Rev. Requirement ##	RTEP Projected Rev. Req't.From Prior Year WS J w/o Incentives	RTEP Rev Req't True-up w/o Incentives	RTEP Projected Rev. Req't.From Prior Year WS J with Incentives **	RTEP Rev Req't True-up with Incentives **	True-up of Incentive with Incentives **
-	-	-	-	-	-	-	$ -		$ -		$ -	$ -
-	-	-	-	-	-	-	$ -		$ -		$ -	$ -
Project Totals		-			-	-	-					

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

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

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	-	-				

Line			
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 ~~2008~~ 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 ~~2008~~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 ~~2008~~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

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

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 (1)			**WEST VIRGINIA** (2)			**FERC WHOLESALE** (3)			**FERC KINGSPORT** (4)			**COMPANY**
	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 4/1/2012

FOR MULTIPLE JURISDICTION COMPANIES

INDIANA MICHIGAN POWER COMPANY

		INDIANA			MICHIGAN			FERC WHOLESALE			COMPANY
		(1)			(2)			(3)			
				WTD AVG.	*MPSC*		*WTD AVG.*			*WTD AVG.*	*WTD AVG.*
	PLANT	*IURC*	*ALLOCATION*	*DEPREC.*	*APPROVED*	*ALLOCATION*	*DEPREC.*	*FERC*	*ALLOCATION*	*DEPREC.*	*DEPREC.*
	ACCT.	*RATES*	*FACTOR (4)*	*RATE*	*RATES*	*FACTOR (4)*	*RATE*	*RATES*	*FACTOR (4)*	*RATE*	*RATE*
TRANSMISSION PLANT											
Land Improvements	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.

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

(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 NOTE 1	(C) Property	(D) Labor	(E) Other	(F) Non-Allocable
1	**Revenue Taxes**					
2	List Individual Taxes Here	-				-
3	**Real Estate and Personal Property Taxes**					
4	Real and Personal Property - Jurisdiction #1	-	-			
5	Real and Personal Property - Jurisdiction #2	-	-			
6	Real and Personal Property - Jurisdiction #3	-	-			
7	Real and Personal Property - Other Jurisdictions	-	-			
8	**Payroll Taxes**					
9	Federal Insurance Contribution (FICA)	-		-		
10	Federal Unemployment Tax	-		-		
11	State Unemployment Insurance	-		-		
12	**Production Taxes**					
13	List Individual Taxes Here	-				-
14		-				-
15	**Miscellaneous Taxes**					
16	List Individual Taxes Here	-				-
17		-			-	
18		-			-	
19		-			-	
20		-			-	
21		-				-
22		-				-
23		-				-
24	Total Taxes by Allocable Basis	-	-	-	-	-

(Total Company Amount Ties to FFI p.114, Ln 14,(c))
NOTE 1: The detail of each total company number and its source in the FERC Form 1 is shown on WS H-1.

Functional Property Tax Allocation

Line No.		Production	Transmsission	Distribution	General	Total
25	Functionalized Net Plant (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**							
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)

Project Description:

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

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

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

CUMULATIVE HISTORY OF PROJECTED ANNUAL REVENUE REQUIREMENTS:

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

RTEP Projected Rev. Req't.From Prior Year Template w/o Incentives		**RTEP Projected Rev. Req't.From Prior Year Template with Incentives ****		

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

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

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

AEP East Companies
Cost of Service Formula Rate Using 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	-

TRUE UP OF PROJECT REVENUE REQUIREMENT FOR PRIOR YEAR:

CUMULATIVE HISTORY OF TRUED-UP ANNUAL REVENUE REQUIREMENTS:

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

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

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. <u>Amounts related to the ineffective portion of pre-issuance hedges, cash settlements of fair value hedges issued on Long Term Debt, post-issuance cash flow hedges, and cash flow hedges of variable rate debt issuances are not recoverable in this formula and are to be recorded in the “Excludable” column below.</u>

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	-	-				

Line			Value
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	<u>**Preferred Stock**</u>	(C)	(D)	<u>**Average**</u>
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

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

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 4/1/2012

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%	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.

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.