AEP EAST Companies Transmission Formula Rate Revenue Requirement Utilizing FERC Form 1 Data For rates effective July 1, 2013

AEP Zone Transmission Service Revenue Requirement

Line No.			AEP Annual Revenue Requirement	APCo Annual Revenue Requirement	I&M Annual Revenue Requirement	KPCo Annual Revenue Requirement	KNG Annual Revenue Requirement	OPCo Annual Revenue Requirement	WPCo Annual Revenue Requirement
Δ Netwa	ork Service								
1 1	REVENUE REQUIREMENT (w/o incentives)	(TCOS Ln 1)	\$715,074,806	\$232,463,494	\$125,959,874	\$55,400,649	\$3,760,479	\$281,223,353	\$16,266,957
2	LESS: REVENUE CREDITS	(TCOS Ln 2)	\$15,741,753	\$3,618,736	\$947,294	\$79,378	\$306,055	\$9,374,004	\$1,416,286
3	CURRENT YEAR ZONE 1 AEP NETWORK SERVICE REVENUE REQUIREMENT	(TCOS Ln 3)	\$699,333,053	\$228,844,758	\$125,012,580	\$55,321,271	\$3,454,424	\$271,849,349	\$14,850,671
4 5 6	LESS: REVENUE REQUIREMENTS INCLUDED IN LINE 1 FOR: RTEP UPGRADES (W/O INCENTIVES) OTHER ZONAL UPGRADES (W/O INCENTIVES)	(TCOS Ln 4) (Worksheet J)	\$8,785,417 \$0	\$1,956,928 \$0	\$2,666,168 \$0	\$0 \$0	\$0 \$0	\$3,768,661 \$0	\$393,660 \$0
/	SUBTOTAL		\$8,785,417	\$1,956,928	\$2,666,168	\$0	\$0	\$3,768,661	\$393,660
8	EXISTING ZONAL ATRR (W/O INCENTIVES)	(Ln 3- Ln 7)	\$690,547,636	\$226,887,831	\$122,346,412	\$55,321,271	\$3,454,424	\$268,080,687	\$14,457,011
9	INCENTIVE REVENUE REQUIREMENT FOR ZONAL PROJECTS	(Worksheet J)	\$0	\$0	\$0	\$0	\$0	\$0	\$0
10	EXISTING ZONAL ATRR (W/ INCENTIVES)	(Ln 8 + Ln 9)	\$690,547,636	\$226,887,831	\$122,346,412	\$55,321,271	\$3,454,424	\$268,080,687	\$14,457,011
11 12 13	BILLED HISTORICAL YEAR (2012) ACTUAL ATRR BILLED PROJECTED (2012) ATRR FROM PRIOR YEAR PRIOR YEAR TRUE-UP	Input from 2012 True-up Input from Prior Year (Ln 11 - Ln 12)	\$645,853,979 \$658,697,053 -\$12,843,074	\$212,282,376 \$213,852,440 -\$1,570,063	\$118,409,508 \$125,523,647 -\$7,114,138	\$52,066,346 \$51,786,703 \$279,643	\$2,579,861 \$2,709,361 -\$129,500	\$251,504,412 \$257,889,879 -\$6,385,468	\$9,011,475 \$6,935,024 \$2,076,452
14	INTEREST ON PRIOR YEAR TRUE UP		-\$754,543	-\$92,243	-\$417,962	\$16,429	-\$7,608	-\$375,152	\$121,994
15	EXISTING ZONAL ATRR FOR PJM OATT	(Ln 10 + Ln 13 + Ln 14)	\$676,950,019	\$225,225,524	\$114,814,311	\$55,617,343	\$3,317,316	\$261,320,067	\$16,655,457
B. Point-	-to-Point Service								
16	2012 AEP East Zone Network Service Peak Load		23,308.6 N	1VV					
17 18 19 20 21 22 23	Annual Point-to-Point Rate in \$/MW - Year Monthly Point-to-Point Rate in \$/MW - Month Weekly Point-to-Point Rate in \$/MW - Weekly Daily On-Peak Point-to-Point Rate in \$/MW - Day Daily Off-Peak Point-to-Point Rate in \$/MW - Day Hourly On-Peak Point-to-Point Rate in \$/MW - Hour Hourly Off-Peak Point-to-Point Rate in \$/MW - Hour	(Ln 15 / Ln 16) (Ln 17 / 12) (Ln 17 / 52) (Ln 17 / 260) (Ln 17 / 365) (Ln 17 / 4160) (Ln 17 / 8760)	\$29,042.93 \$2,420.24 \$558.52 \$111.70 \$79.57 \$6.98 \$3.32						
	Regional Service RTEP UPGRADE ATRR W/O INCENTIVES	/I n 7\	0 705 //7	1 056 020	2 666 160			2 760 661	202 660
24 25 26 26a	ADDITIONAL ATRR FOR FERC-APPROVED INCENTIVES ON RTEP TRUE-UP ADJUSTMENT INCLUDING INTEREST DOCKET NO. AC10-47 ADJUSTMENT (JMG Acquisition)	(Ln 7) (Worksheet J)	8,785,417 - (344,539) -	1,956,928 - 297,512 -	2,666,168 - (132,763) -	- - -	- - -	3,768,661 - (509,288) -	393,660 - - -
27	RTEP ATRR FOR PJM COLLECTION UNDER SCHEDULE 12		\$ 8,440,878	2,254,439	2,533,405			3,259,373	393,660

AEP EAST Companies Transmission Formula Rate Revenue Requirement Utilizing FERC Form 1 Data For rates effective July 1, 2013

AEP Transmission Schedule 1A Revenue Requirements

Line No.			AEP Annual Revenue Requirement	APCo Annual Revenue Requirement	I&M Annual Revenue Requirement	KPCo Annual Revenue Requirement	KNG Annual Revenue Requirement	OPCo Annual Revenue Requirement	WPCo Annual Revenue Requirement
	dule 1A ARR Total Load Dispatch & Scheduling (Account 561) (TCOS Line 14)		\$37,112,586	\$10,758,518	\$8,132,792	\$2,313,221	\$50,457	\$15,750,749	\$106,849
2	Less: Load Disptach - Scheduling, System Control and Dispatch Less: Load Disptach - Reliability, Planning & Standards Developr	,	\$20,583,439 \$4,274,634	\$5,714,454 \$1,211,704	\$5,531,795 \$1,083,397	\$1,160,718 \$245,515	\$1,263 \$0	\$8,170,124 \$1,734,018	\$5,085 \$0
4	Total 561 Internally Developed Costs	(Ln 1 - Ln 2 - Ln 3)	\$12,254,513	\$3,832,360	\$1,517,600	\$906,988	\$49,194	\$5,846,607	\$101,764
5	Less: PTP Service Credit		\$1,283,673	\$394,538	\$170,004	\$92,534	\$4,975	\$612,966	\$8,655
6	EXISTING ZONAL ARR	(Ln 4 - Ln 5)	\$10,970,840	\$3,437,822	\$1,347,596	\$814,454	\$44,219	\$5,233,641	\$93,109
7	BILLED HISTORICAL YEAR (2012) ACTUAL ARR BILLED PROJECTED (2012) ARR FROM PRIOR YEAR	Input from 2012 True-up Input from Prior Year	\$10,970,840 \$10,761,555	\$3,374,706 \$3,309,699	\$1,460,086 \$1,430,625	\$804,719 \$786,251	\$43,377 \$42,357	\$5,211,279 \$5,118,020	\$76,674 \$74,603
9	PRIOR YEAR TRUE-UP	(Ln 7 - Ln 8)	\$209,285	\$65,007	\$29,460	\$18,468	\$1,021	\$93,259	\$2,071
10	INTEREST ON PRIOR YEAR TRUE UP		\$4,747	\$1,460	\$632	\$348	\$19	\$2,255	\$33
11	Net Schedule 1A Revenue Requirement for Zone		\$11,184,872	\$3,504,289	\$1,377,688	\$833,269	\$45,258	\$5,329,154	\$95,213

B. Schedule 1A Rate Calculations

2012 AEP East Zone Annual MWh

134,854,616 MWh

13 AEP Zone Rate for Schedule 1A Service.

(Line 11 / Line 12)

\$0.0829

APPALACHIAN POWER COMPANY

Total	Line No.						Tr	ransmission Amount
2 REVENUE CREDITS (Note A) (Worksheet E) 3,618,736 DA 1,0000 \$ 3,618,735 3 REVENUE REQUIREMENT For All Company Facilities (In 1 less In 2) \$ 228,844,75 MEMO: The Carrying Charge Calculations on lines 6 to 11 below are used in calculating project revenue requirements billed through PJM Schedule 12, Transmission Enhancement Charges. The total non-incentive revenue requirements for these projects shown on line 4 is included in the total on line 3. 4 Revenue Requirement for PJM Schedule 12 Facilities (w/o incentives) (Worksheet J) 1,956,928 DA 1,0000 \$ 1,956,928 5 NET PLANT CARRYING CHARGE w/o intra-AEP charges or credits or ROE incentives (Note B) 6 Annual Rate (In 6 / 12) 15,73 6 Annual Rate (In 6 / 12) 1,31 1,31 8 NET PLANT CARRYING CHARGE ON LINE 6, w/o depreciation or ROE incentives (Note B) (In 1 - In 105 - In 106 - In 111 - In 112) //(In 48 + In 49 + In 50 + In 51 + In 53) x 100)) 13,45 10 NET PLANT CARRYING CHARGE ON LINE 9, w/o Return come taxes or ROE incentives (Note B) (In 1 - In 105 - In 106 - In 111 - In 112 - In 133 - In 134) //(In 48 + In 49 + In 50 + In 51 + In 53) x 100)) 3,92 10 NET PLANT CARRYING CHARGE ON LINE 9, w/o Return come taxes or ROE incentives (Note	1	REVENUE REQUIREMENT (w/o incentives)	(In 138)	Tatal	A II a			\$232,463,494
MEMO: The Carrying Charge Calculations on lines 6 to 11 below are used in calculating project revenue requirements billed through PJM Schedule 12, Transmission Enhancement Charges. The total non-incentive revenue requirements for these projects shown on line 4 is included in the total on line 3. 4 Revenue Requirement for PJM Schedule 12 Facilities (w/o incentives) (Worksheet J) 1,956,928 DA 1.0000 \$ 1,956,92 5 NET PLANT CARRYING CHARGE w/o intra-AEP charges or credits or ROE incentives (Note B) 6 Annual Rate ((ln 1 - ln 105 - ln 106)/(ln 48 + ln 49 + ln 50 + ln 51 + ln 53) x 100)) 15,73 7 Monthly Rate ((ln 6 / 12) 1,31 8 NET PLANT CARRYING CHARGE ON LINE 6, w/o depreciation or ROE incentives (Note B) 9 Annual Rate ((ln 1 - ln 105 - ln 106 - ln 111 - ln 112) //(ln 48 + ln 49 + ln 50 + ln 51 + ln 53) x 100)) 13,45 10 NET PLANT CARRYING CHARGE ON LINE 9, w/o Return, income taxes or ROE incentives (Note B) 11 Annual Rate ((ln 1 - ln 105 - ln 106 - ln 111 - ln 112 - ln 133 - ln 134) //(ln 48 + ln 49 + ln 50 + ln 51 + ln 53) x 100)) 3,92 12 ADDITIONAL REVENUE REQUIREMENT for projects w/ incentive ROE's (Note B) (Worksheet J) 13 REVENUE REQUIREMENT FOR SCHEDULE 1A CHARGES 14 Total Load Dispatch & Scheduling (Account 561) Line 85 Below 10,758,51 15 Less: Load Dispatch - Scheduling, System Control and Dispatch Services (321,88.b) 5,714,46 16 Less: Load Dispatch - Reliability, Planning & Standards Development Services (321,92.b) 1,211,70	2	REVENUE CREDITS	(Note A) (Worksheet E)				\$	3,618,736
12, Transmission Enhancement Charges. The total non-incentive revenue requirements for these projects shown on line 4 is included in the total on line 3. Revenue Requirement for PJM Schedule 12 Facilities (w/o incentives) (Worksheet J) 1,956,928 DA 1,00000 \$1,956,928 NET PLANT CARRYING CHARGE w/o intra-AEP charges or credits or ROE incentives (Note B) Annual Rate ((In 1 - In 105 - In 106)/((In 48 + In 49 + In 50 + In 51 + In 53) x 100)) 10,757,77 Nonthly Rate ((In 1 - In 105 - In 106 - In 1111 - In 112)/((In 48 + In 49 + In 50 + In 51 + In 53) x 100)) 11,345,92 12, ADDITIONAL REVENUE REQUIREMENT for projects w/ incentive ROE's (Note B) (Worksheet J) 13 14. Total Load Dispatch & Scheduling (Account 561) 15. Less: Load Dispatch - Scheduling, System Control and Dispatch Services (321.88.b) 16. Less: Load Dispatch - Reliability, Planning & Standards Development Services (321.92.b)	3	REVENUE REQUIREMENT For All Company Facilities	(In 1 less In 2)				\$	228,844,758
NET PLANT CARRYING CHARGE w/o intra-AEP charges or credits or ROE incentives (Note B) Annual Rate ((In 1 - In 105 - In 106)/((In 48 + In 49 + In 50 + In 51 + In 53) x 100)) NET PLANT CARRYING CHARGE ON LINE 6, w/o depreciation or ROE incentives (Note B) Annual Rate ((In 1 - In 105 - In 106 - In 111 - In 112) /((In 48 + In 49 + In 50 + In 51 + In 53) x 100)) NET PLANT CARRYING CHARGE ON LINE 9, w/o Return, income taxes or ROE incentives (Note B) Annual Rate ((In 1 - In 105 - In 106 - In 111 - In 112 - In 133 - In 134) /((In 48 + In 49 + In 50 + In 51 + In 53) x 100)) ADDITIONAL REVENUE REQUIREMENT for projects w/ incentive ROE's (Note B) (Worksheet J) REVENUE REQUIREMENT FOR SCHEDULE 1A CHARGES Total Load Dispatch & Scheduling (Account 561) Line 85 Below Less: Load Dispatch - Scheduling, System Control and Dispatch Services (321.88.b) Less: Load Dispatch - Reliability, Planning & Standards Development Services (321.92.b) 15.73 16.75 17.75 18.76 19.75	12, Tran			_				
Annual Rate ((ln 1 - ln 105 - ln 106)/((ln 48 + ln 49 + ln 50 + ln 51 + ln 53) x 100)) (ln 6 / 12) 1.31 NET PLANT CARRYING CHARGE ON LINE 6, w/o depreciation or ROE incentives (Note B) Annual Rate ((ln 1 - ln 105 - ln 106 - ln 111 - ln 112) //((ln 48 + ln 49 + ln 50 + ln 51 + ln 53) x 100)) 13.45 NET PLANT CARRYING CHARGE ON LINE 9, w/o Return, income taxes or ROE incentives (Note B) Annual Rate ((ln 1 - ln 105 - ln 106 - ln 111 - ln 112) //((ln 48 + ln 49 + ln 50 + ln 51 + ln 53) x 100)) 3.92 ADDITIONAL REVENUE REQUIREMENT for projects w/ incentive ROE's (Note B) (Worksheet J) REVENUE REQUIREMENT FOR SCHEDULE 1A CHARGES Total Load Dispatch & Scheduling (Account 561) Line 85 Below 10,758,51 Less: Load Dispatch - Scheduling, System Control and Dispatch Services (321.88.b) 5,714,45 Less: Load Dispatch - Reliability, Planning & Standards Development Services (321.92.b) 1,211,70	4	Revenue Requirement for PJM Schedule 12 Facilities (v	w/o incentives) (Worksheet J)	1,956,928	DA	1.00000	\$	1,956,928
Annual Rate ((In 1 - In 105 - In 106 - In 111 - In 112) /((In 48 + In 49 + In 50 + In 51 + In 53) x 100)) NET PLANT CARRYING CHARGE ON LINE 9, w/o Return, income taxes or ROE incentives (Note B) Annual Rate ((In 1 - In 105 - In 106 - In 111 - In 112 - In 133 - In 134) /((In 48 + In 49 + In 50 + In 51 + In 53) x 100)) 3.92 ADDITIONAL REVENUE REQUIREMENT for projects w/ incentive ROE's (Note B) (Worksheet J) REVENUE REQUIREMENT FOR SCHEDULE 1A CHARGES 14 Total Load Dispatch & Scheduling (Account 561) Line 85 Below Less: Load Dispatch - Scheduling, System Control and Dispatch Services (321.88.b) Less: Load Dispatch - Reliability, Planning & Standards Development Services (321.92.b) 13.45 14.45 15 Less: Load Dispatch - Reliability, Planning & Standards Development Services (321.92.b)	5 6 7	Annual Rate	((ln 1 - ln 105 - ln 106)/((ln 48 + ln 49 + ln 5	0 + ln 51 + ln 53) x 100))				15.73% 1.31%
Annual Rate ((In 1 - In 105 - In 106 - In 111 - In 133 - In 134) /((In 48 + In 49 + In 50 + In 51 + In 53) x 100)) ADDITIONAL REVENUE REQUIREMENT for projects w/ incentive ROE's (Note B) (Worksheet J) REVENUE REQUIREMENT FOR SCHEDULE 1A CHARGES Total Load Dispatch & Scheduling (Account 561) Line 85 Below Less: Load Dispatch - Scheduling, System Control and Dispatch Services (321.88.b) Less: Load Dispatch - Reliability, Planning & Standards Development Services (321.92.b) 11 Annual Rate ((In 1 - In 105 - In 106 - In 111 - In 133 - In 134) /((In 48 + In 49 + In 50 + In 51 + In 53) x 100)) 12 ADDITIONAL REVENUE REQUIREMENT for projects w/ incentive ROE's (Note B) (Worksheet J) 13 PREVENUE REQUIREMENT FOR SCHEDULE 1A CHARGES 14 Total Load Dispatch & Scheduling (Account 561) Line 85 Below 15 Less: Load Dispatch - Scheduling, System Control and Dispatch Services (321.88.b) 16 Less: Load Dispatch - Reliability, Planning & Standards Development Services (321.92.b)		•	,	ı 48 + ln 49 + ln 50 + ln 51 + ln 53) x 1	00))			13.45%
13 REVENUE REQUIREMENT FOR SCHEDULE 1A CHARGES 14 Total Load Dispatch & Scheduling (Account 561) Line 85 Below 15 Less: Load Dispatch - Scheduling, System Control and Dispatch Services (321.88.b) 16 Less: Load Dispatch - Reliability, Planning & Standards Development Services (321.92.b) 17 Total Load Dispatch & Scheduling, System Control and Dispatch Services (321.88.b) 18 Less: Load Dispatch - Reliability, Planning & Standards Development Services (321.92.b)		•	,		ln 51 + ln 53) x	100))		3.92%
Total Load Dispatch & Scheduling (Account 561) Line 85 Below Less: Load Dispatch - Scheduling, System Control and Dispatch Services (321.88.b) Less: Load Dispatch - Reliability, Planning & Standards Development Services (321.92.b) 10,758,51 5,714,45 11,211,70	12	ADDITIONAL REVENUE REQUIREMENT for projects was	incentive ROE's (Note B) (Worksheet J)					-
Less: Load Dispatch - Scheduling, System Control and Dispatch Services (321.88.b) Less: Load Dispatch - Reliability, Planning & Standards Development Services (321.92.b) 15 Less: Load Dispatch - Reliability, Planning & Standards Development Services (321.92.b)	13		REVENUE REQUIREMENT FOR SCH	HEDULE 1A CHARGES				
	15	Less: Load Dispatch - Scheduling, System Control and I	Dispatch Services (321.88.b)					10,758,518 5,714,454
17 TOTAL DO FINICENTATIV DEVELODED COSTS (LINE 14 - LINE 10 - LINE 10)	16 17	Less: Load Dispatch - Reliability, Planning & Standards Total 561 Internally Developed Costs	Development Services (321.92.b) (Line 14 - Line 15 - Line 16)					1,211,704 3,832,360

APPALACHIAN POWER COMPANY

(1) (2) (3) (4) (5)

		Data Sources				Total
Line	RATE BASE CALCULATION	(See "General Notes")	<u>TO Total</u> NOTE C	Allo	<u>cator</u>	<u>Transmission</u>
No.	GROSS PLANT IN SERVICE					
18	Production	(Worksheet A In 1.C)	5,620,438,618	NA	0.00000	-
19	Less: Production ARO (Enter Negative)	(Worksheet A In 2.C)	(71,986,517)	NA	0.00000	-
20	Transmission	(Worksheet A In 3.C & Ln 142)	2,040,266,144	DA	0.07500	1,989,664,925
21	Less: Transmission ARO (Enter Negative)	(Worksheet A In 4.C& Ln 143)	-	TP	0.97520	-
22	Plus: Transmission Plant-in-Service Additions (Work	•	140,824,365	DA	1.00000	140,824,365
23 24	Plus: Additional Trans Plant on Transferred Assets (Distribution	(Worksheet A In 5.C)	2,988,920,393	DA NA	1.00000 0.00000	<u>-</u>
2 4 25	Less: Distribution ARO (Enter Negative)	(Worksheet A In 6.C)	(3,069)	NA NA	0.00000	<u>-</u>
26	General Plant	(Worksheet A In 7.C)	195,239,795	W/S	0.07081	13,825,109
27	Less: General Plant ARO (Enter Negative)	(Worksheet A In 8.C)	(811,747)	W/S	0.07081	(57,481)
28	Intangible Plant	(Worksheet A In 9.C)	123,626,312	W/S	0.07081	8,754,093
29	TOTAL GROSS PLANT	(sum lns 18 to 28)	11,036,514,294			2,153,011,011
30	ACCUMULATED DEPRECIATION AND AMORTIZATION)N				
31	Production	(Worksheet A In 12.C)	2,022,105,333	NA	0.00000	_
32	Less: Production ARO (Enter Negative)	(Worksheet A In 13.C)	(30,813,283)	NA	0.00000	_
33	Transmission	(Worksheet A In 14.C & 28.C)	629,801,174	TP1=	0.98245	618,746,248
34	Less: Transmission ARO (Enter Negative)	(Worksheet A In 15.C)	-	TP1=	0.98245	-
35	Plus: Transmission Plant-in-Service Additions (Work	,	1,562,690	DA	1.00000	1,562,690
36	Plus: Additional Projected Deprec on Transferred As		-	DA	1.00000	-
37	Plus: Additional Transmission Depreciation for 2013		32,626,776	TP1	0.98245	32,054,077
38	Plus: Additional General & Intangible Depreciation for		19,855,273	W/S	0.07081	1,405,970
39	Plus: Additional Accum Deprec on Transferred Asse		-	DA	1.00000	-
40	Distribution	(Worksheet A In 16.C)	918,499,290	NA	0.00000	-
41	Less: Distribution ARO (Enter Negative)	(Worksheet A In 17.C)	(1,517)	NA	0.00000	-
42	General Plant	(Worksheet A In 18.C)	63,986,336	W/S	0.07081	4,530,931
43	Less: General Plant ARO (Enter Negative)	(Worksheet A In 19.C)	(594,444)	W/S	0.07081	(42,093)
44	Intangible Plant	(Worksheet A In 20.C)	91,986,512	W/S	0.07081	6,513,649
45	TOTAL ACCUMULATED DEPRECIATION	(sum lns 31 to 44)	3,749,014,141			664,771,472
46	NET PLANT IN SERVICE					
47	Production	(ln 18 + ln 19 - ln 31 - ln 32)	3,557,160,051			-
48	Transmission	(ln 20 + ln 21 - ln 33 - ln 34)	1,410,464,970			1,370,918,678
49	Plus: Transmission Plant-in-Service Additions (In 22		139,261,675			139,261,675
50	Plus: Additional Trans Plant on Transferred Assets		-			-
51	Plus: Additional Transmission Depreciation for 2013	· ·	(32,626,776)			(32,054,077)
52	Plus: Additional General & Intangible Depreciation for		(19,855,273)			(1,405,970)
53	Plus: Additional Accum Deprec on Transferred Asse	, , ,	-			-
54	Distribution	(ln 24 + ln 25 - ln 40 - ln 41)	2,070,419,551			- 0.70.700
55	General Plant	(ln 26 + ln 27 - ln 42 - ln 43)	131,036,156			9,278,790
56	Intangible Plant TOTAL NET PLANT IN SERVICE	(ln 28 - ln 44)	31,639,800 7,287,500,153			2,240,443
57	TOTAL NET PLANT IN SERVICE	(sum lns 47 to 56)	7,207,300,133			1,488,239,539
58	DEFERRED TAX ADJUSTMENTS TO RATE BASE	(Note D)				
59	Account No. 281.1 (enter negative)	(Worksheet B, In 2 & In 5.C)	(197,320,252)	NA		_
60	Account No. 282.1 (enter negative)	(Worksheet B, In 7 & In 10.C)	(1,229,418,143)	DA		(289,461,122)
61	Account No. 283.1 (enter negative)	(Worksheet B, In 12 & In 15.C)	(431,851,994)	DA		(30,244,723)
62	Account No. 190.1	(Worksheet B, In 17 & In 20.C)	399,990,470	DA		50,244,301
63	Account No. 255 (enter negative)	(Worksheet B, In 24 & In 25.C)	(2,822,664)	DA		(641,429)
64	TOTAL ADJUSTMENTS	(sum lns 59 to 63)	(1,461,422,583)			(270,102,973)
65	PLANT HELD FOR FUTURE USE	(Worksheet A In 29.C & In 30.C)	5,319,071	DA		1,877,675
66	REGULATORY ASSETS	(Worksheet A In 36. (C))	-	DA		-
67	WORKING CAPITAL	(Note E)				
68	Cash Working Capital	(1/8 * In 88)	3,978,581			3,879,907
69	Transmission Materials & Supplies	(Worksheet C, In 2.(D))	1,508,480	TP	0.97520	1,471,068
70	A&G Materials & Supplies	(Worksheet C, In 3.(D))	825,807	W/S	0.07081	58,476
71	Stores Expense	(Worksheet C, In 4.(D))	-	GP(h)	0.18468	-
72 70	Prepayments (Account 165) - Labor Allocated	(Worksheet C, In 6.G)	203,768,047	W/S	0.07081	14,429,002
73 74	Prepayments (Account 165) - Gross Plant	(Worksheet C, In 6.F)	3,057,772	GP(h)	0.18468	564,701
74 75	Prepayments (Account 165) - Transmission Only	(Worksheet C, In 6.E)	12,816	DA	1.00000	12,816
75 76	Prepayments (Account 165) - Unallocable	(Worksheet C, In 6.D)	(201,506,924)	NA	0.00000	
76	TOTAL WORKING CAPITAL	(sum lns 68 to 75)	11,644,579			20,415,970
77	IPP CONTRIBUTIONS FOR CONSTRUCTION	(Note F) (Worksheet D, In 7.B)	(2,445,715)	DA	1.00000	(2,445,715)
78	RATE BASE (sum Ins 57, 64, 65, 66, 76, 77)		5,840,595,504			1,237,984,496

APPALACHIAN POWER COMPANY

(1) (2) (3) (4) (5)

	EXPENSE, TAXES, RETURN & REVENUE REQUIREMENTS CALCULATION	Data Sources (See "General Notes")	<u>TO Total</u>	Allo	cator	Total <u>Transmission</u>
Line						
No.	OPERATION & MAINTENANCE EXPENSE					
79	Production	321.80.b	1,892,122,758			
80	Distribution	322.156.b	115,706,381			
81 82	Customer Related Expense Regional Marketing Expenses	322.164,171,178.b 322.131.b	53,414,582 5,904,349			
83	Transmission	321.112.b	64,421,229			
84	TOTAL O&M EXPENSES	(sum lns 79 to 83)	2,131,569,299			
85	Less: Total Account 561	(Note G) (Worksheet F, In 15.C)	10,758,518			
86	Less: Account 565	(Note H) 321.96.b	35,116,817			
87	Less: State Regulatory Deferrals & Amortizations	(Note I) (Worksheet F, In 4.C)	(13,282,753)			
88	Total O&M Allocable to Transmission	(Ins 83 - 85 - 86 - 87)	31,828,647	TP	0.97520	31,039,256
89	Administrative and General	323.197.b (Note J)	115,443,349			
90	Less: Acct. 924, Property Insurance	323.185.b	2,893,399			
91	Acct. 9260039 PBOP Expense	PBOP Worksheet O Line 9 & 10, (Note K)	10,321,493			
92	Acct. 9260057 PBOP Medicare Subsidy	PBOP Worksheet O Line 11, (Note K)	-			
93	PBOP Expense Billed From AEPSC	PBOP Worksheet O Line 13, (Note K)	1,038,300			
94	Acct. 928, Reg. Com. Exp.	323.189.b	2,048,123			
95 06	Acct. 930.1, Gen. Advert. Exp.	323.191.b	1,213,171			
96	Acct. 930.2, Misc. Gen. Exp.	323.192.b	6,334,522	\\/\O	0.07004	0.405.070
97	Balance of A & G	(ln 89 - sum ln 90 to ln 96)	91,594,341	W/S	0.07081	6,485,879
98 99	Plus: Acct. 924, Property Insurance Acct. 928 - Transmission Specific	(In 90) Worksheet F In 19.(E) (Note L)	2,893,399	GP(h) TP	0.18468 0.97520	534,345
100	Acct 930.1 - Only safety related ads -Direct	Worksheet F In 36.(E) (Note L)	_	TP	0.97520	-
100	Acct 930.1 - Only safety related ads -Direct Acct 930.2 - Misc Gen. Exp Trans	Worksheet F In 44.(E) (Note L)	785,229	DA	1.00000	785,229
102	Settlement Approved PBOP Recovery	PBOP Worksheet O, Col. C, Line 1, (Note M)	13,362,440	W/S	0.07081	946,207
103	A & G Subtotal	(sum lns 97 to 102)	108,635,409	,0	0.07.001	8,751,660
104	O & M EXPENSE SUBTOTAL	(ln 88 + ln 103)	140,464,056			39,790,916
105	Plus: TEA Settlement in Account 565	Company Records (Note H)	-	DA	1.00000	-
106	Plus: Transmission Lease Payments To Affiliates in A		-	DA	1.00000	-
107	TOTAL O & M EXPENSE	(ln 104 + ln 105 + ln 106)	140,464,056			39,790,916
108	DEPRECIATION AND AMORTIZATION EXPENSE					
109	Production	336.2-6.f	167,860,265	NA	0.00000	-
110	Distribution	336.8.f	101,779,757	NA	0.00000	-
111	Transmission	336.7.f	32,626,776	TP1	0.98245	32,054,077
112	Plus: Transmission Plant-in-Service Additions (Works	sheet I In 21.I)	1,562,690	DA	1.00000	1,562,690
113	General	336.10.f	3,140,253	W/S	0.07081	222,364
114	Intangible	336.1.f	16,715,020	W/S	0.07081	1,183,606
115	TOTAL DEPRECIATION AND AMORTIZATION	(Lns 109+110+111 +112+113+114)	323,684,761			35,022,737
116	TAXES OTHER THAN INCOME	(Note N)				
117	Labor Related					
118	Payroll	Worksheet H In 23.(D)	8,830,131	W/S	0.07081	625,270
119	Plant Related					
120	Property	Worksheet H In 23.(C) & In 58.(C)	50,923,379	DA		14,495,326
121	Gross Receipts/Sales & Use	Worksheet H In 23.(F)	33,724,260	NA OD(L)	0.00000	4 500 050
122	Other	Worksheet H In 23.(E)	8,137,707	GP(h)	0.18468	1,502,850
123	TOTAL OTHER TAXES	(sum lns 118 to 122)	101,615,477			16,623,445
124	INCOME TAXES	(Note O)				
125	T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =		39.32%			
126	EIT=(T/(1-T)) * (1-(WCLTD/WACC)) =		42.12%			
127	where WCLTD=(In 162) and WACC = (In 165)					
128 129	and FIT, SIT & p are as given in Note O.		1.6470			
130	GRCF=1 / (1 - T) = (from In 125) Amortized Investment Tax Credit (enter negative)	(FF1 p.114, ln 19.c)	1.6479 (397,195)			
131	Income Tax Calculation	(In 126 * In 134)	197,252,636			41,810,070
131	ITC adjustment	(III 120 III 134) (In 129 * In 130)	(654,530)	NP(h)	0.19199	(125,661)
133	TOTAL INCOME TAXES	(sum lns 131 to 132)	196,598,106	141 (11)	0.10100	41,684,409
		,				
134	RETURN ON RATE BASE (Rate Base * WACC)	(ln 78 * ln 165)	468,310,711		4.00000	99,264,090
135	INTEREST ON IPP CONTRIBUTION FOR CONST. (Not		77,897	DA	1.00000	77,897
136	(Gains) / Losses on Sales of Plant Held for Future Use (-			-
137	Tax Impact on (Gains) / Losses on Sales of Plant Held f	or Future Use (In 136 * In126)				
138	TOTAL REVENUE REQUIREMENT (sum lns 107, 115, 123, 133, 134, 135, 136, 137)		1,230,751,008			232,463,494

APPALACHIAN POWER COMPANY

SUPPORTING CALCULATIONS

ln N								
No.	TRANSMISSION PLANT INCLUDED IN PJM TARIFF	(1-, 00)						0.040.000.444
139	Total transmission plant	(ln 20)						2,040,266,144
140	Less transmission plant excluded from PJM Tariff (Note	,	(Note O)					- 50 601 210
141	Less transmission plant included in OATT Ancillary Serv		(Note Q)				_	50,601,219
142	Transmission plant included in PJM Tariff	(ln 139 - ln 140 - ln 141)						1,989,664,925
143	Percent of transmission plant in PJM Tariff	(ln 142 / ln 139)					TP	0.97520
				Payroll Billed from				
144	WAGES & SALARY ALLOCATOR (W/S)	(Note R)	Direct Payroll	AEP Service Corp.	Total			
145	Production	354.20.b	57,348,833	20,738,274	78,087,107	NA	0.00000	-
146	Transmission	354.21.b	4,649,255	5,848,397	10,497,652	TP	0.97520	10,237,297
147	Regional Market Expenses	354.22.b	0	0	-	NA	0.00000	-
148	Distribution	354.23.b	34,664,664	4,515,151	39,179,815	NA	0.00000	-
149	Other (Excludes A&G)	354.24,25,26.b	8,613,542	8,194,178	16,807,720	NA	0.00000	-
150	Total	(sum lns 145 to 149)	105,276,294	39,296,000	144,572,294		_	10,237,297
454	Transmission related amount						W/S=	0.07081
151	Transmission related amount						VV/3=	0.07001
							W /3=	
152	WEIGHTED AVERAGE COST OF CAPITAL (WACC)	(Worksheet L. In. 35, col. (D))					-	\$
152 153	WEIGHTED AVERAGE COST OF CAPITAL (WACC) Long Term Interest	(Worksheet L, In. 35, col. (D)) (Worksheet L, In. 40, col. (D))					-	
152 153 154	WEIGHTED AVERAGE COST OF CAPITAL (WACC) Long Term Interest Preferred Dividends	(Worksheet L, In. 35, col. (D)) (Worksheet L, In. 40, col. (D))					-	\$
152 153 154 155	WEIGHTED AVERAGE COST OF CAPITAL (WACC) Long Term Interest Preferred Dividends Development of Common Stock:	(Worksheet L, In. 40, col. (D))					-	\$ 190,506,524 -
152 153 154 155 156	WEIGHTED AVERAGE COST OF CAPITAL (WACC) Long Term Interest Preferred Dividends	(Worksheet L, In. 40, col. (D)) (FF1 p 112, Ln 16.c)					-	\$
152 153 154 155	WEIGHTED AVERAGE COST OF CAPITAL (WACC) Long Term Interest Preferred Dividends Development of Common Stock: Proprietary Capital	(Worksheet L, In. 40, col. (D)) (FF1 p 112, Ln 16.c) (FF1 p 112, Ln 3.c)					-	\$ 190,506,524 - 3,052,563,357 -
152 153 154 155 156 157	WEIGHTED AVERAGE COST OF CAPITAL (WACC) Long Term Interest Preferred Dividends Development of Common Stock: Proprietary Capital Less: Preferred Stock	(Worksheet L, In. 40, col. (D)) (FF1 p 112, Ln 16.c)					-	\$ 190,506,524 -
152 153 154 155 156 157 158	WEIGHTED AVERAGE COST OF CAPITAL (WACC) Long Term Interest Preferred Dividends Development of Common Stock: Proprietary Capital Less: Preferred Stock Less: Account 216.1	(Worksheet L, In. 40, col. (D)) (FF1 p 112, Ln 16.c) (FF1 p 112, Ln 3.c) (FF1 p 112, Ln 12.c))				-	\$ 190,506,524 - 3,052,563,357 - 1,654,344
152 153 154 155 156 157 158 159	WEIGHTED AVERAGE COST OF CAPITAL (WACC) Long Term Interest Preferred Dividends Development of Common Stock: Proprietary Capital Less: Preferred Stock Less: Account 216.1 Less: Account 219	(Worksheet L, In. 40, col. (D)) (FF1 p 112, Ln 16.c) (FF1 p 112, Ln 3.c) (FF1 p 112, Ln 12.c) (FF1 p 112, Ln 15.c))				Cost	\$ 190,506,524 - 3,052,563,357 - 1,654,344 (29,897,592)
152 153 154 155 156 157 158 159 160	WEIGHTED AVERAGE COST OF CAPITAL (WACC) Long Term Interest Preferred Dividends Development of Common Stock: Proprietary Capital Less: Preferred Stock Less: Account 216.1 Less: Account 219	(Worksheet L, In. 40, col. (D)) (FF1 p 112, Ln 16.c) (FF1 p 112, Ln 3.c) (FF1 p 112, Ln 12.c) (FF1 p 112, Ln 15.c))	\$	%		Cost (Note S)	\$ 190,506,524 - 3,052,563,357 - 1,654,344 (29,897,592) 3,080,806,605 Weighted
152 153 154 155 156 157 158 159 160	WEIGHTED AVERAGE COST OF CAPITAL (WACC) Long Term Interest Preferred Dividends Development of Common Stock: Proprietary Capital Less: Preferred Stock Less: Account 216.1 Less: Account 219	(Worksheet L, In. 40, col. (D)) (FF1 p 112, Ln 16.c) (FF1 p 112, Ln 3.c) (FF1 p 112, Ln 12.c) (FF1 p 112, Ln 15.c))	\$ 3,709,883,415	% 54.63%		- Cost	\$ 190,506,524 - 3,052,563,357 - 1,654,344 (29,897,592) 3,080,806,605
152 153 154 155 156 157 158 159 160 161 162 163	WEIGHTED AVERAGE COST OF CAPITAL (WACC) Long Term Interest Preferred Dividends Development of Common Stock: Proprietary Capital Less: Preferred Stock Less: Account 216.1 Less: Account 219 Common Stock Long Term Debt (Note T) Worksheet L, In 35, col. (B)) Preferred Stock (In 157)	(Worksheet L, In. 40, col. (D)) (FF1 p 112, Ln 16.c) (FF1 p 112, Ln 3.c) (FF1 p 112, Ln 12.c) (FF1 p 112, Ln 15.c)		3,709,883,415	54.63% 0.00%		Cost (Note S) 0.0514	\$ 190,506,524 - 3,052,563,357 - 1,654,344 (29,897,592) 3,080,806,605 Weighted 0.0281 0.0000
152 153 154 155 156 157 158 159 160	WEIGHTED AVERAGE COST OF CAPITAL (WACC) Long Term Interest Preferred Dividends Development of Common Stock: Proprietary Capital Less: Preferred Stock Less: Account 216.1 Less: Account 219 Common Stock Long Term Debt (Note T) Worksheet L, In 35, col. (B))	(Worksheet L, In. 40, col. (D)) (FF1 p 112, Ln 16.c) (FF1 p 112, Ln 3.c) (FF1 p 112, Ln 12.c) (FF1 p 112, Ln 15.c))	•	54.63%		Cost (Note S)	\$ 190,506,524 - 3,052,563,357 - 1,654,344 (29,897,592) 3,080,806,605 Weighted 0.0281

APPALACHIAN POWER COMPANY

<u>Letter</u> <u>Notes</u>

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

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

See Worksheet E for details.

- B The annual and monthly net plant carrying charges on page 1 are used to compute the revenue requirement for RTEP sponsored upgrades or those projects receiving approved incentive-ROE's.
- C Transmission Plant balances in this study are projected as of December 31, 2013. Other ratebase amounts are as of December 31, 2012.
- The total-company balances shown for Accounts 281, 282, 283, 190 only reflect ADIT that relates to utility operations. The balance of Account 255 is reduced by prior flow throughs and is completely excluded if the utility chose to utilize amortization of tax credits against FIT expense. An exception to this is pre-1971 ITC balances, which are required to be taken as an offset to rate base. Account 281 is not allocated. In compliance with FERC Rulemaking RM02-7-000, Asset Retirement Obligation deferrals have been removed from ratebase. Transmission ADIT allocations are shown on WS B.

The company will not include the ADIT portion of deferred hedge gains and losses in rate base.

- E Cash Working Capital assigned to transmission is one-eighth of O&M allocated to transmission, as shown on line 88. It excludes:
 - 1) Load Scheduling & Dispatch Charges in account 561 that are collected in the OATT Ancilliary Services Revenue, as shown on line 85.
 - 2) AEP transmission equalization transfers, as shown on line 86
 - 3) The impact of state regulatory deferrals and amortizations, as shown on line 87
 - 4) All A&G Expenses, as shown on line 103.
- F Consistent with Paragraph 657 of Order 2003-A, the amount on line 77 is equal to the balance of IPP System Upgrade Credits owed to transmission customers that made contributions toward the construction of System upgrades, and includes accrued interest and unreturned balance of contributions. The annual interest expense is included on line 135.
- Removes from the cost of service the Load Scheduling and Dispatch expenses booked to accounts 561.1 through 561.8. Expenses recorded in these accounts, with the exception of 561.4 & 561.8 (lines 15 & 16 above) are recovered in Schedule 1A, OATT ancillary services rates. See Worksheet F, lines 6 through 15, for descriptions and the Form 1 Source of these accounts' balances.
- Removes cost of transmission service provided by others to determine the basis of cash working capital on line 88. To the extent such service is incurred to provide the PJM service at issue, e.g. transmission equalization agreement, such costs are added back on lines 105 and 106 to determine the total O&M collected in the formula. The amounts on lines 105 and 106 are also excluded in the calculation of the FCR percentage calculated on lines 5 through 11. The addbacks on lines 105 and 106 of activity recorded in 565 represents inter-company sales or purchases of transmission capacity necessary to meet each AEP company's transmission load relative to their available transmission capacity.

The company records referenced on lines 105 and 106 is the APPALACHIAN POWER COMPANY general ledger.

- I Removes the impact of state regulatory deferrals or their amortization from O&M expense.
- J General Plant and Administrative & General expenses, other than in accounts 924, 928, and 930, will be functionalized based on the Wages & Salaries "W/S" allocator. The allocation basis for accounts 924, 928 and 930 are separately presented in the formula. A change in the allocation method for an account must be approved via a 205 filing with the FERC.
- K These deductions on lines 91 through 93 are to remove from the cost of service the expenses recorded by the company for Postemployment Benefits Other than Pensions (PBOP). See Note M below for the recoverable PBOP expense.
- Expenses reported for these A&G accounts will be included in the cost of service only to the extent they are directly assignable to transmission service. Worksheet F allocates these expense items. Acct 928 Includes Regulatory Commission expenses itemized in FERC Form-1 at page 351, column H. FERC Assessment Fees and Annual Charges shall not be allocated to transmission. Only safety-related and educational advertising costs in Account 930.1 are included in the TCOS. Account 930.2 includes the expenses incurred by the transmission function for Associated Business Development revenues given as a credit to the TCOS on Worksheet E.
- M See note K above. Per the settlement in Docket ER08-1329, recoverable PBOP expense is based on an annual total for the operating companies that is ratioed to them based on the total of actual annual PBOP costs, including charges from the AEP Service Corportation. The calculation of the recoverable amount for each company is shown on Worksheet O, and the process for updating the annual total is documented on Attachment F, Allowable PBOP Expense Formula.
- N Includes only FICA, unemployment, highway, property and other assessments charged in the current year. Gross receipts, sales & use and taxes related to income are excluded.
- The currently effective income tax rate, where FIT is the Federal income tax rate; SIT is the State income tax rate, and p = the percentage of federal income tax deductible for state income taxes. See Worksheet G for the development of the Company's composite SIT. A utility that elected to utilize amortization of tax credits against taxable income, rather than book tax credits to Account No. 255 and reduce rate base, must reduce its income tax expense by the amount of the Amortized Investment Tax Credit (Form 1, 266.8.f) (In 130) multiplied by (1/1-T). If the applicable tax rates are zero enter 0.

Inputs Required:

FIT = 35.00%

SIT= 6.64% (State Income Tax Rate or Composite SIT. Worksheet G))
p = 0.00% (percent of federal income tax deductible for state purposes)

- P Removes plant excluded from the OATT because it does not meet the PJM's definition of Transmission Facilities or is otherwise ineligible to be recovered under the OATT.
- Q Removes transmission plant (e.g. step-up transformers) included in the development of OATT ancillary service rates and not already removed for reasons indicated in Note P.
- R Includes functional wages & salaries billed by AEP Service Corporation for support of the operating company.
- Long Term Debt cost rate = long-term interest (ln 153) / long term debt (ln 162). Preferred Stock cost rate = preferred dividends (ln 154) / preferred outstanding (ln 163). Common Stock cost rate (ROE) = 11.49%, the rate accepted by FERC in Docket No. ER08-1329. It includes an additional 50 basis points for PJM RTO membership. In the Projected & Historic templates, the interest expense on long-term debt is the sum of a full year's interest expense at the coupon rate for each issuance outstanding as of December 31 of the historic year. The projected expense for variable rate debt will be based on the effective rate at December 31. These conventions ensure that the expense used in the projection will reflect a full year, similar to the actual expense that will appear in the subsequent true-up of the projection, and minimize the impact on the true-up of using a partial year interest expense. The projection will reflect the actual historic-year expense recorded for issuance expenses, discounts and premiums, and gains or losses on reacquired debt. Eligible hedging gains or losses will be limited to five basis points of the projected capital structure. Details and calculations are shown on Worksheet L.
- T This note only applies to Indiana Michigan Power Company.
- U This note only applies to the true-up template.

APPALACHIAN POWER COMPANY

Line							nsmission Amount
No. 166	REVENUE REQUIREMENT (w/o incentives)	(ln 303)					218,844,211
	,	,	Total	Alloc	ator	·	, ,
167	REVENUE CREDITS	(Note A) (Worksheet E)	3,618,736	DA	1.00000	\$	3,618,736
168	REVENUE REQUIREMENT For All Company Facilities	(In 166 less In 167)				\$ 2	215,225,475
	The Carrying Charge Calculations on lines 171 to 176 ismission Enhancement Charges. The total non-incent.	• • •					
169	Not applicable on this template						
170	NET PLANT CARRYING CHARGE w/o intra-AEP charg	ges or credits or ROE incentives (Note B)					
171	Annual Rate	((ln 166 - ln 270 - ln 271)/ ln 213 x 100)					15.96%
172	Monthly Rate	(ln 171 / 12)					1.33%
173	NET PLANT CARRYING CHARGE ON LINE 171, w/o	depreciation or ROE incentives (Note B)					
174	Annual Rate	((ln 166 - ln 270 - ln 271 - ln 276) / ln 213 x	100)				13.63%
175	NET PLANT CARRYING CHARGE ON LINE 174, w/o	Return, income taxes or ROE incentives (Note	B)				
176	Annual Rate	((ln 166 - ln 270 - ln 271 - ln 276 - ln 298 - ln	,				4.22%
177	Not applicable on this template						
178		REVENUE REQUIREMENT FO	OR SCHEDULE 1A CHARGES				
170	Total Load Dispetch & Schoduling (Account 554)	Line 250 Polow					10 750 510
179 180	Total Load Dispatch & Scheduling (Account 561)	Line 250 Below					10,758,518
180	Less: Load Dispatch - Scheduling, System Control and						5,714,454
181	Less: Load Dispatch - Reliability, Planning & Standards	Development Services (321.92.b)					1,211,704
182	Total 561 Internally Developed Costs	(Line 179 - Line 180 - Line 181)					3,832,360

APPALACHIAN POWER COMPANY

	(1)	(2)	(3)	(4	1)	(5)
Line	RATE BASE CALCULATION	Data Sources (See "General Notes")	<u>TO Total</u> NOTE C	Alloc	eator	Total <u>Transmission</u>
No.	GROSS PLANT IN SERVICE		NOTE C			
183	Production	(Worksheet A In 1.C)	5,620,438,618	NA	0.00000	_
184	Less: Production ARO (Enter Negative)	(Worksheet A In 2.C)	(71,986,517)	NA	0.00000	_
185	Transmission	(Worksheet A In 3.C & Ln 307)	2,040,266,144	DA	0.0000	1,989,664,925
186	Less: Transmission ARO (Enter Negative)	(Worksheet A In 4.C& Ln 308)	-	TP	0.97520	-
187	Plus: Transmission Plant-in-Service Additions (Wor	·	N/A	NA	0.00000	N/A
188	Plus: Additional Trans Plant on Transferred Assets		N/A	NA	0.00000	N/A
189	Distribution	(Worksheet A In 5.C)	2,988,920,393	NA	0.00000	-
190	Less: Distribution ARO (Enter Negative)	(Worksheet A In 6.C)	(3,069)	NA	0.00000	_
191	General Plant	(Worksheet A In 7.C)	195,239,795	W/S	0.07081	13,825,109
192	Less: General Plant ARO (Enter Negative)	(Worksheet A In 8.C)	(811,747)	W/S	0.07081	(57,481)
193	Intangible Plant	(Worksheet A In 9.C)	123,626,312	W/S	0.07081	8,754,093
194	TOTAL GROSS PLANT	(sum Ins 183 to 193)	10,895,689,929	GP(h)=	0.184677	2,012,186,646
134	TOTAL GROSS I LAINT	(30111113 103 to 193)	10,035,003,323	GTD=	0.39562	2,012,100,040
195	ACCUMULATED DEPRECIATION AND AMORTIZAT	TION		015-	0.00002	
196	Production	(Worksheet A In 12.C)	2,022,105,333	NA	0.00000	_
197	Less: Production ARO (Enter Negative)	(Worksheet A In 13.C)	(30,813,283)	NA	0.00000	_
198	Transmission	(Worksheet A In 14.C & 28.C)	629,801,174	TP1=	0.98245	618,746,248
199	Less: Transmission ARO (Enter Negative)	(Worksheet A In 15.C)	-	TP1=	0.98245	010,740,240
200	Plus: Transmission Plant-in-Service Additions (Wor	,	N/A	DA	1.00000	N/A
	•			DA		
201	Plus: Additional Projected Deprec on Transferred A		N/A		1.00000	N/A
202	Plus: Additional Transmission Depreciation for 2013		N/A	TP1	0.98245	N/A
203	Plus: Additional General & Intangible Depreciation f		N/A	W/S	0.07081	N/A
204	Plus: Additional Accum Deprec on Transferred Ass		N/A	DA	1.00000	N/A
205	Distribution	(Worksheet A In 16.C)	918,499,290	NA	0.00000	-
206	Less: Distribution ARO (Enter Negative)	(Worksheet A In 17.C)	(1,517)	NA	0.00000	/
207	General Plant	(Worksheet A In 18.C)	63,986,336	W/S	0.07081	4,530,931
208	Less: General Plant ARO (Enter Negative)	(Worksheet A In 19.C)	(594,444)	W/S	0.07081	(42,093)
209	Intangible Plant	(Worksheet A In 20.C)	91,986,512	W/S	0.07081	6,513,649
210	TOTAL ACCUMULATED DEPRECIATION	(sum Ins 196 to 209)	3,694,969,402			629,748,735
211	NET PLANT IN SERVICE					
211		/ln 102 ln 104 ln 106 ln 107\	2 557 160 051			
212 213	Production	(In 183 + In 184 - In 196 - In 197) (In 185 + In 186 - In 198 - In 199)	3,557,160,051			1 270 010 670
	Transmission	,	1,410,464,970 N/A			1,370,918,678
214	Plus: Transmission Plant-in-Service Additions (In 18	,				N/A
215	Plus: Additional Trans Plant on Transferred Assets	•	N/A			N/A
216	Plus: Additional Transmission Depreciation for 2013		N/A			N/A
217	Plus: Additional General & Intangible Depreciation f		N/A			N/A
218	Plus: Additional Accum Deprec on Transferred Ass	, , ,	N/A			N/A
219	Distribution	(ln 189 + ln 190 - ln 205 - ln 206)	2,070,419,551			-
220	General Plant	(ln 191 + ln 192 - ln 207 - ln 208)	131,036,156			9,278,790
221	Intangible Plant	(ln 193 - ln 209)	31,639,800			2,240,443
222	TOTAL NET PLANT IN SERVICE	(sum Ins 212 to 221)	7,200,720,527	NP(h)=	0.191986	1,382,437,911
223	DEFERRED TAX ADJUSTMENTS TO RATE BASE	(Note D)				
223 224	Account No. 281.1 (enter negative)	(Worksheet B, In 2 & In 5.C)	(197,320,252)	NA		
224 225	Account No. 281.1 (enter negative) Account No. 282.1 (enter negative)	(Worksheet B, In 7 & In 10.C)	(1,229,418,143)	DA		(289,461,122)
225 226	Account No. 283.1 (enter negative) Account No. 283.1 (enter negative)	(Worksheet B, In 12 & In 15.C)	(431,851,994)	DA		(30,244,723)
220 227	Account No. 190.1	(Worksheet B, In 17 & In 15.0)	399,990,470	DA		50,244,723)
228	Account No. 255 (enter negative)	(Worksheet B, In 24 & In 25.C)	(2,822,664)	DA		(641,429)
229	TOTAL ADJUSTMENTS	(sum lns 224 to 228)	(1,461,422,583)	DA		(270,102,973)
223	TOTAL ADJUSTIMENTS	(30111 1113 224 10 220)	(1,401,422,505)			(270,102,973)
230	PLANT HELD FOR FUTURE USE	(Worksheet A In 29.C & In 30.C)	5,319,071	DA		1,877,675
231	REGULATORY ASSETS	(Worksheet A In 36. (C))	-	DA		-
232	WORKING CAPITAL	(Note E)				
233	Cash Working Capital	(1/8 * In 253)	3,978,581			3,879,907
234	Transmission Materials & Supplies	(Worksheet C, In 2.(D))	1,508,480	TP	0.97520	1,471,068
235	A&G Materials & Supplies	(Worksheet C, In 3.(D))	825,807	W/S	0.07081	58,476
236	Stores Expense	(Worksheet C, In 4.(D))	-	GP(h)	0.18468	-
237	Prepayments (Account 165) - Labor Allocated	(Worksheet C, In 6.G)	203,768,047	W/S	0.07081	14,429,002
238	Prepayments (Account 165) - Gross Plant	(Worksheet C, In 6.F)	3,057,772	GP(h)	0.18468	564,701
239	Prepayments (Account 165) - Transmission Only	(Worksheet C, In 6.E)	12,816	DA	1.00000	12,816
240	Prepayments (Account 165) - Unallocable	(Worksheet C, In 6.D)	(201,506,924)	NA	0.00000	-
241	TOTAL WORKING CAPITAL	(sum Ins 233 to 240)	11,644,579			20,415,970
 · ·		(,,			_0, 0, 0 . 0
0.40	IDD CONTRIBUTIONS FOR CONSTRUCTION		(0.445.545)	5 4		()

DA

1.00000

(2,445,715)

5,753,815,878

(2,445,715)

1,132,182,868

(Note F) (Worksheet D, In 7.B)

IPP CONTRIBUTIONS FOR CONSTRUCTION

243

RATE BASE (sum Ins 222, 229, 230, 231, 241, 242)

APPALACHIAN POWER COMPANY

(1) (2) (3) (4)

	EXPENSE, TAXES, RETURN & REVENUE REQUIREMENTS CALCULATION	Data Sources (See "General Notes")	TO Total	Alloc	ator	Total Transmission
Line	NEGOINEMENTO GAEGOLATION	(Gee General Notes)	<u>10 10tal</u>	Alloc	<u>acor</u>	<u> </u>
No.	OPERATION & MAINTENANCE EXPENSE					
244	Production	321.80.b	1,892,122,758			
245	Distribution	322.156.b	115,706,381			
246	Customer Related Expense	322 & 323.164,171,178.b	53,414,582			
247	Regional Marketing Expenses	322.131.b	5,904,349			
248 249	Transmission TOTAL O&M EXPENSES	321.112.b	64,421,229			
2 4 9 250	Less: Total Account 561	(sum lns 244 to 248) (Note G) (Worksheet F, ln 15.C)	2,131,569,299 10,758,518			
251	Less: Account 565	(Note H) 321.96.b	35,116,817			
252	Less: Regulatory Deferrals & Amortizations	(Note I) (Worksheet F, In 4.C)	(13,282,753)			
253	Total O&M Allocable to Transmission	(Ins 248 - 250 - 251 - 252)	31,828,647	TP	0.97520	31,039,256
254	Administrative and General	323.197.b (Note J)	115,443,349			
255	Less: Acct. 924, Property Insurance	323.185.b	2,893,399			
256	Acct. 9260039 PBOP Expense	PBOP Worksheet O Line 9 & 10, (Note K)	10,321,493			
257	Acct. 9260057 PBOP Medicare Subsidy	PBOP Worksheet O Line 11, (Note K)	-			
258	PBOP Expense Billed From AEPSC	PBOP Worksheet O Line 13, (Note K)	1,038,300			
259	Acct. 928, Reg. Com. Exp.	323.189.b	2,048,123			
260	Acct. 930.1, Gen. Advert. Exp.	323.191.b	1,213,171			
261 262	Acct. 930.2, Misc. Gen. Exp. Balance of A & G	323.192.b	6,334,522	W/S	0.07081	6,485,879
263	Plus: Acct. 924, Property Insurance	(In 254 - sum In 255 to In 261) (In 255)	91,594,341 2,893,399	GP(h)	0.18468	534,345
264	Acct. 928 - Transmission Specific	Worksheet F In 19.(E) (Note L)	-	TP	0.97520	-
265	Acct 930.1 - Only safety related ads -Direct	Worksheet F In 36.(E) (Note L)	-	TP	0.97520	-
266	Acct 930.2 - Misc Gen. Exp Trans	Worksheet F In 44.(E) (Note L)	785,229	DA	1.00000	785,229
267	Settlement Approved PBOP Recovery	PBOP Worksheet O, Col. C, Line 1, (Note M)	13,362,440	W/S	0.07081	946,207
268	A & G Subtotal	(sum Ins 262 to 267)	108,635,409			8,751,660
269	O & M EXPENSE SUBTOTAL	(ln 253 + ln 268)	140,464,056			39,790,916
270	Plus: TEA Settlement in Account 565	Company Records (Note H)	-	DA	1.00000	-
271	Plus: Transmission Lease Payments To Affiliates in A		-	DA	1.00000	-
272	TOTAL O & M EXPENSE	(ln 269 + ln 270 + ln 271)	140,464,056			39,790,916
273	DEPRECIATION AND AMORTIZATION EXPENSE					
274	Production	336.2-6.f	167,860,265	NA	0.00000	-
275	Distribution	336.8.f	101,779,757	NA TD4	0.00000	-
276 277	Transmission Plus: Transmission Plant-in-Service Additions (Works)	336.7.f	32,626,776 N/A	TP1	0.98245	32,054,077 N/A
277 278	General	336.10.f	3,140,253	W/S	0.07081	222,364
279	Intangible	336.1.f	16,715,020	W/S	0.07081	1,183,606
280	TOTAL DEPRECIATION AND AMORTIZATION	(Ln 274+275+	322,122,071			33,460,047
004	TAYES STUED THAN 1000ME	276+277+278+279)				
281 282	TAXES OTHER THAN INCOME Labor Related	(Note N)				
283	Payroll	Worksheet H In 23.(D)	8,830,131	W/S	0.07081	625,270
284	Plant Related	Weineries (11 m 20.(2)	0,000,101	,0	0.07001	020,270
285	Property	Worksheet H In 23.(C) & In 58.(C)	50,923,379	DA		14,495,326
286	Gross Receipts/Sales & Use	Worksheet H In 23.(F)	33,724,260	NA OR(I)	0.00000	-
287 288	Other TOTAL OTHER TAXES	Worksheet H In 23.(E) (sum Ins 283 to 287)	8,137,707	GP(h)	0.18468	1,502,850
200	TOTAL OTHER TAXES	(Sulli IIIS 203 to 201)	101,615,477			16,623,445
289	INCOME TAXES	(Note O)				
290	T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =		39.32%			
291	EIT=(T/(1-T)) * (1-(WCLTD/WACC)) =		42.12%			
292 293	where WCLTD=(In 327) and WACC = (In 330) and FIT, SIT & p are as given in Note O.					
294	GRCF=1 / (1 - T) = (from ln 290)		1.6479			
295	Amortized Investment Tax Credit (enter negative)	(FF1 p.114, ln 19.c)	(397,195)			
000		(la 004 * la 000)	404.004.054			00 000 00 :
296	Income Tax Calculation	(ln 291 * ln 299)	194,321,854	ND(b)	0.10100	38,236,864
297 298	ITC adjustment TOTAL INCOME TAXES	(In 294 * In 295) (sum Ins 296 to 297)	(654,530) 193,667,324	NP(h)	0.19199	(125,661) 38,111,203
200	. J I I I I I J J I I I I I I I I I I I	(33111110 200 to 201)	100,001,027			50,111,200
299	RETURN ON RATE BASE (Rate Base*WACC)	(ln 243 * ln 330)	461,352,545			90,780,703
300	INTEREST ON IPP CONTRIBUTION FOR CONST. (No	te F) (Worksheet D, In 2.(B))	77,897	DA	1.00000	77,897
301	(Gains) / Losses on Sales of Plant Held for Future Use (V	Vorksheet N, In 4, Cols. ((F) & (H))	-			-
302	Tax Impact on Net Loss / (Gain) on Sales of Plant Held	for Future Use (In 301 * In291)	-			-
303	TOTAL REVENUE REQUIREMENT (sum lns 272, 280, 288, 298, 299, 300, 301, 302)		1,219,299,371			218,844,211
	(30111 1113 21 2, 200, 200, 230, 233, 300, 301, 302)					

APPALACHIAN POWER COMPANY

SUPPORTING CALCULATIONS

ln								
No.	TRANSMISSION PLANT INCLUDED IN PJM TARIFF							
304	Total transmission plant	(ln 185)						2,040,266,144
305	Less transmission plant excluded from PJM Tariff (Note	eP)						
306	Less transmission plant included in OATT Ancillary Serv	vices (Worksheet A, In 23, Co	I. (C)) (Note Q)					50,601,219
307	Transmission plant included in PJM Tariff	(In 304 - In 305 - In 306)						1,989,664,925
308	Percent of transmission plant in PJM Tariff	(In 307 / In 304)					TP=	0.97520
				Payroll Billed from				
309	WAGES & SALARY ALLOCATOR (W/S)	(Note R)	Direct Payroll	AEP Service Corp.	Total			
310	Production	354.20.b	57,348,833	· · · · · · · · · · · · · · · · · · ·	78,087,107	NA	0.0000	-
311	Transmission	354.21.b	4,649,255		10,497,652	TP	0.97520	10,237,297
312	Regional Market Expenses	354.22.b	0	0	-	NA	0.0000	-
313	Distribution	354.23.b	34,664,664	4,515,151	39,179,815	NA	0.00000	-
314	Other (Excludes A&G)	354.24,25,26.b	8,613,542	8,194,178	16,807,720	NA	0.00000	-
315	Total	(sum Ins 310 to 314)	105,276,294	39,296,000	144,572,294			10,237,297
			✓	\checkmark				
316	Transmission related amount						W/S=	0.07081
316	Transmission related amount						W/S=	0.07081
							W/S=	0.07081 \$
317	WEIGHTED AVERAGE COST OF CAPITAL (WACC)	(Worksheet L, In. 35, col. (D)))				W/S= _	\$
		(Worksheet L, In. 35, col. (D (Worksheet L, In. 40, col. (D	,,				W/S= _	
317 318	WEIGHTED AVERAGE COST OF CAPITAL (WACC) Long Term Interest		,,				W/S= _	\$
317 318 319	WEIGHTED AVERAGE COST OF CAPITAL (WACC) Long Term Interest Preferred Dividends		,,				W/S= _	\$
317 318 319 320	WEIGHTED AVERAGE COST OF CAPITAL (WACC) Long Term Interest Preferred Dividends Development of Common Stock:	(Worksheet L, In. 40, col. (D	,,				W/S=	\$ 190,506,524 -
317 318 319 320 321	WEIGHTED AVERAGE COST OF CAPITAL (WACC) Long Term Interest Preferred Dividends Development of Common Stock: Proprietary Capital	(Worksheet L, In. 40, col. (D (FF1 p 112, Ln 16.c)	,,				W/S=	\$ 190,506,524 -
317 318 319 320 321 322	WEIGHTED AVERAGE COST OF CAPITAL (WACC) Long Term Interest Preferred Dividends Development of Common Stock: Proprietary Capital Less: Preferred Stock	(Worksheet L, In. 40, col. (D (FF1 p 112, Ln 16.c) (FF1 p 112, Ln 3.c)	,,				W/S=	\$ 190,506,524 - 3,052,563,357 -
317 318 319 320 321 322 323	WEIGHTED AVERAGE COST OF CAPITAL (WACC) Long Term Interest Preferred Dividends Development of Common Stock: Proprietary Capital Less: Preferred Stock Less: Account 216.1	(Worksheet L, In. 40, col. (D (FF1 p 112, Ln 16.c) (FF1 p 112, Ln 3.c) (FF1 p 112, Ln 12.c))))				W/S=	\$ 190,506,524 - 3,052,563,357 - 1,654,344
317 318 319 320 321 322 323 324	WEIGHTED AVERAGE COST OF CAPITAL (WACC) Long Term Interest Preferred Dividends Development of Common Stock: Proprietary Capital Less: Preferred Stock Less: Account 216.1 Less: Account 219	(Worksheet L, In. 40, col. (D (FF1 p 112, Ln 16.c) (FF1 p 112, Ln 3.c) (FF1 p 112, Ln 12.c) (FF1 p 112, Ln 15.c))))				W/S=	\$ 190,506,524 - 3,052,563,357 - 1,654,344 (29,897,592)
317 318 319 320 321 322 323 324 325	WEIGHTED AVERAGE COST OF CAPITAL (WACC) Long Term Interest Preferred Dividends Development of Common Stock: Proprietary Capital Less: Preferred Stock Less: Account 216.1 Less: Account 219	(Worksheet L, In. 40, col. (D (FF1 p 112, Ln 16.c) (FF1 p 112, Ln 3.c) (FF1 p 112, Ln 12.c) (FF1 p 112, Ln 15.c))))	\$	%			\$ 190,506,524 - 3,052,563,357 - 1,654,344 (29,897,592) 3,080,806,605 Weighted
317 318 319 320 321 322 323 324 325	WEIGHTED AVERAGE COST OF CAPITAL (WACC) Long Term Interest Preferred Dividends Development of Common Stock: Proprietary Capital Less: Preferred Stock Less: Account 216.1 Less: Account 219 Common Stock Long Term Debt (Note T) Worksheet L, In 35, col. (B))	(Worksheet L, In. 40, col. (D (FF1 p 112, Ln 16.c) (FF1 p 112, Ln 3.c) (FF1 p 112, Ln 12.c) (FF1 p 112, Ln 15.c) (In 321 - In 322 - In 323 - In 3)))	\$ 3,709,883,415	54.63%		Cost	\$ 190,506,524 - 3,052,563,357 - 1,654,344 (29,897,592) 3,080,806,605 Weighted 0.0281
317 318 319 320 321 322 323 324 325 326 327 328	WEIGHTED AVERAGE COST OF CAPITAL (WACC) Long Term Interest Preferred Dividends Development of Common Stock: Proprietary Capital Less: Preferred Stock Less: Account 216.1 Less: Account 219 Common Stock Long Term Debt (Note T) Worksheet L, In 35, col. (B)) Preferred Stock (In 322)	(Worksheet L, In. 40, col. (D (FF1 p 112, Ln 16.c) (FF1 p 112, Ln 3.c) (FF1 p 112, Ln 12.c) (FF1 p 112, Ln 15.c) (In 321 - In 322 - In 323 - In 3)))	3,709,883,415	54.63% 0.00%		Cost (Note S) 0.0514	\$ 190,506,524 - 3,052,563,357 - 1,654,344 (29,897,592) 3,080,806,605 Weighted 0.0281 0.0000
317 318 319 320 321 322 323 324 325	WEIGHTED AVERAGE COST OF CAPITAL (WACC) Long Term Interest Preferred Dividends Development of Common Stock: Proprietary Capital Less: Preferred Stock Less: Account 216.1 Less: Account 219 Common Stock Long Term Debt (Note T) Worksheet L, In 35, col. (B))	(Worksheet L, In. 40, col. (D (FF1 p 112, Ln 16.c) (FF1 p 112, Ln 3.c) (FF1 p 112, Ln 12.c) (FF1 p 112, Ln 15.c) (In 321 - In 322 - In 323 - In 3)))		54.63%		Cost (Note S)	\$ 190,506,524 - 3,052,563,357 - 1,654,344 (29,897,592) 3,080,806,605 Weighted 0.0281

APPALACHIAN POWER COMPANY

<u>Letter</u> <u>Notes</u>

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

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

See Worksheet E for details.

- B The annual and monthly net plant carrying charges on page 1 are used to compute the revenue requirement for RTEP sponsored upgrades or those projects receiving approved incentive-ROE's.
- Transmission Plant balances in this study are historic as of December 31, 2012.
- The total-company balances shown for Accounts 281, 282, 283, 190 only reflect ADIT that relates to utility operations. The balance of Account 255 is reduced by prior flow throughs and is completely excluded if the utility chose to utilize amortization of tax credits against FIT expense. An exception to this is pre-1971 ITC balances, which are required to be taken as an offset to rate base. Account 281 is not allocated. In compliance with FERC Rulemaking RM02-7-000, Asset Retirement Obligation deferrals have been removed from ratebase. Transmission ADIT allocations are shown on WS B.

The company will not include the ADIT portion of deferred hedge gains and losses in rate base.

- E Cash Working Capital assigned to transmission is one-eighth of O&M allocated to transmission, as shown on line 253. It excludes:
 - 1) Load Scheduling & Dispatch Charges in account 561 that are collected in the OATT Ancilliary Services Revenue, as shown on line 250.
 - 2) AEP transmission equalization transfers, as shown on line 251
 - 3) The impact of state regulatory deferrals and amortizations, as shown on line 252
 - 4) All A&G Expenses, as shown on line 268.
- F Consistent with Paragraph 657 of Order 2003-A, the amount on line 242 is equal to the balance of IPP System Upgrade Credits owed to transmission customers that made contributions toward the construction of System upgrades, and includes accrued interest and unreturned balance of contributions. The annual interest expense is included on line 300.
- Removes from the cost of service the Load Scheduling and Dispatch expenses booked to accounts 561.1 through 561.8. Expenses recorded in these accounts, with the exception of 561.4 & 561.8 (lines 180 & 181 above) are recovered in Schedule 1A, OATT ancillary services rates. See Worksheet F, lines 6 through 15, for descriptions and the Form 1 Source of these accounts' balances.
- H Removes cost of transmission service provided by others to determine the basis of cash working capital on line 253. To the extent such service is incurred to provide the PJM service at issue, e.g. transmission equalization agreement, such costs are added back on lines 270 and 271 to determine the total O&M collected in the formula. The amounts on lines 270 and 271 are also excluded in the calculation of the FCR percentage calculated on lines 170 through 176.

The addbacks on lines 270 and 271 of activity recorded in 565 represents inter-company sales or purchases of transmission capacity necessary to meet each AEP company's transmission load relative to their available transmission capacity.

The company records referenced on lines 270 and 271 is the APPALACHIAN POWER COMPANY general ledger.

- I Removes the impact of state regulatory deferrals or their amortization from O&M expense.
- J General Plant and Administrative & General expenses, other than in accounts 924, 928, and 930, will be functionalized based on the Wages & Salaries "W/S" allocator. The allocation basis for accounts 924, 928 and 930 are separately presented in the formula. A change in the allocation method for an account must be approved via a 205 filing with the FERC.
- K These deductions on lines 256 through 258 are to remove from the cost of service the expenses recorded by the company for Postemployment Benefits Other than Pensions (PBOP). See Note M below for the recoverable PBOP expense.
- Expenses reported for these A&G accounts will be included in the cost of service only to the extent they are directly assignable to transmission service. Worksheet F allocates these expense items. Acct 928 Includes Regulatory Commission expenses itemized in FERC Form-1 at page 351, column H. FERC Assessment Fees and Annual Charges shall not be allocated to transmission. Only safety-related and educational advertising costs in Account 930.1 are included in the TCOS. Account 930.2 includes the expenses incurred by the transmission function for Associated Business Development revenues given as a credit to the TCOS on Worksheet E.
- M See note K above. Per the settlement in Docket ER08-1329, recoverable PBOP expense is based on an annual total for the operating companies that is ratioed to them based on the total of actual annual PBOP costs, including charges from the AEP Service Corportation. The calculation of the recoverable amount for each company is shown on Worksheet O, and the process for updating the annual total is documented on Attachment F, Allowable PBOP Expense Formula.

35.00%

- N Includes only FICA, unemployment, highway, property and other assessments charged in the current year. Gross receipts, sales & use and taxes related to income are excluded.
- The currently effective income tax rate, where FIT is the Federal income tax rate; SIT is the State income tax rate, and p = the percentage of federal income tax deductible for state income taxes. See Worksheet G for the development of the Company's composite SIT. A utility that elected to utilize amortization of tax credits against taxable income, rather than book tax credits to Account No. 255 and reduce rate base, must reduce its income tax expense by the amount of the Amortized Investment Tax Credit (Form 1, 266.8.f)

 (In 295) multiplied by (1/1-T). If the applicable tax rates are zero enter 0.

SIT=

p = 6.64% (State Income Tax Rate or Composite SIT. Worksheet G))

(percent of federal income tax deductible for state purposes)

- P Removes plant excluded from the OATT because it does not meet the PJM's definition of Transmission Facilities or is otherwise ineligible to be recovered under the OATT.
- Q Removes transmission plant (e.g. step-up transformers) included in the development of OATT ancillary service rates and not already removed for reasons indicated in Note P.
- R Includes functional wages & salaries billed by AEP Service Corporation for support of the operating company.

FIT =

S Long Term Debt cost rate = long-term interest (ln 318) / long term debt (ln 327). Preferred Stock cost rate = preferred dividends (ln 319) / preferred outstanding (ln 328). Common Stock cost rate (ROE) = 11.49%, the rate accepted by FERC in Docket No. ER08-1329. It includes an additional 50 basis points for remaining a member of the PJM RTO.

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

- T This note only applies to Indiana Michigan Power Company.
- U This note only applies to the true-up template.

Inputs Required:

APPALACHIAN POWER COMPANY

Line No.						T	ransmission Amount
1	REVENUE REQUIREMENT (w/o incentives)	(In 138)	Total	Δ.II			\$218,162,992
2	REVENUE CREDITS	(Note A) (Worksheet E)	Total 3,618,736	DA	1.00000	\$	3,618,736
3	REVENUE REQUIREMENT For All Company Facilities	(In 1 less In 2)				\$	214,544,256
	The Carrying Charge Calculations on lines 6 to 11 belo smission Enhancement Charges. The total non-incent 3.		-				
4	Revenue Requirement for PJM Schedule 12 Facilities (w	/o incentives) (Worksheet K)	2,261,880	DA	1.00000	\$	2,261,880
5	NET PLANT CARRYING CHARGE w/o intra-AEP charge	s or credits or ROE incentives (Note B)					
6	Annual Rate	((ln 1 - ln 105 - ln 106)/ ln 48 x 100)					16.26%
7	Monthly Rate	(ln 6 / 12)					1.35%
8	NET PLANT CARRYING CHARGE ON LINE 6, w/o depr	eciation or ROE incentives (Note B)					
9	Annual Rate	((ln 1 - ln 105 - ln 106 - ln 111) / ln 48 x 100)					13.87%
10	NET PLANT CARRYING CHARGE ON LINE 9, w/o Retu	rn, income taxes or ROF incentives (Note B)					
11	Annual Rate	((ln 1 - ln 105 - ln 106 - ln 111 - ln 133 - ln 134	4) / In 48 x 100)				4.33%
12	ADDITIONAL REVENUE REQUIREMENT for projects w/	incentive ROE's (Note B) (Worksheet K)					-
13		REVENUE REQUIREMENT FOR SCH	EDULE 1A CHARGES				
14	Total Load Dispatch & Scheduling (Account 561)	Line 85 Below					10,758,518
15	Less: Load Dispatch - Scheduling, System Control and D						5,714,454
16	Less: Load Dispatch - Reliability, Planning & Standards D						1,211,704
17	Total 561 Internally Developed Costs	(Line 14 - Line 15 - Line 16)				_	3,832,360
-	J	, , , , , , , , , , , , , , , , , , , ,					-,-,-,

APPALACHIAN POWER COMPANY

	(1)	(2)	(3)		(4)	(5)
	RATE BASE CALCULATION	Data Sources (See "General Notes")	TO Total	Allo	ocator	Total <u>Transmission</u>
Line No.	GROSS PLANT IN SERVICE		NOTE C			
18	Production	(Worksheet A In 1.E)	5,401,632,776	NA	0.00000	-
19 20	Less: Production ARO (Enter Negative) Transmission	(Worksheet A In 2.E) (Worksheet A In 3.E & Ln 142)	(69,957,445) 1,991,143,960	NA DA	0.00000	- 1,950,233,379
21	Less: Transmission ARO (Enter Negative)	(Worksheet A In 4.E & Ln 143)		TP	0.97945	-
22	Plus: Transmission Plant-in-Service Additions (Works	,	N/A	NA	0.00000	N/A
23 24	Plus: Additional Trans Plant on Transferred Assets (\) Distribution	(Worksheet A In 5.E)	N/A 2,915,443,722	NA NA	0.00000 0.00000	N/A
2 4 25	Less: Distribution ARO (Enter Negative)	(Worksheet A In 6.E)	(3,069)	NA NA	0.00000	- -
26	General Plant	(Worksheet A In 7.E)	192,101,022	W/S	0.07112	13,662,202
27	Less: General Plant ARO (Enter Negative)	(Worksheet A In 8.E)	(811,747)	W/S	0.07112	(57,731)
28	Intangible Plant	(Worksheet A In 9.E)	116,437,753	W/S	0.07112	8,281,039
29	TOTAL GROSS PLANT	(sum Ins 18 to 28)	10,545,986,971	GP(h)= GTD=	0.18700 0.00000	1,972,118,889
30	ACCUMULATED DEPRECIATION AND AMORTIZATION					
31	Production	(Worksheet A In 12.E)	1,950,527,566	NA	0.00000	-
32 33	Less: Production ARO (Enter Negative) Transmission	(Worksheet A In 13.E) (Worksheet A In 14.E & 28.E)	(28,423,680) 618,690,832	NA TP1=	0.00000 0.98317	608,276,893
34	Less: Transmission ARO (Enter Negative)	(Worksheet A In 15.E)	-	TP1=	0.98317	-
35	Plus: Transmission Plant-in-Service Additions (Works	,	N/A	DA	1.00000	N/A
36	Plus: Additional Projected Deprec on Transferred As	•	N/A	DA	1.00000	N/A
37	Plus: Additional Transmission Depreciation for 2013		N/A	TP1	0.98317	N/A
38	Plus: Additional General & Intangible Depreciation fo	,	N/A	W/S	0.07112	N/A
39	Plus: Additional Accum Deprec on Transferred Asse		N/A	DA	1.00000	N/A
40 41	Distribution Less: Distribution ARO (Enter Negative)	(Worksheet A In 16.E) (Worksheet A In 17.E)	892,488,682 (1,482)	NA NA	0.00000 0.00000	-
42	General Plant	(Worksheet A In 18.E)	63,406,955	W/S	0.07112	4,509,495
43	Less: General Plant ARO (Enter Negative)	(Worksheet A In 19.E)	(430,773)	W/S	0.07112	(30,637)
44	Intangible Plant	(Worksheet A In 20.E)	87,125,001	W/S	0.07112	6,196,320
45	TOTAL ACCUMULATED DEPRECIATION	(sum Ins 31 to 44)	3,583,383,100			618,952,071
46	NET PLANT IN SERVICE					
47	Production	(ln 18 + ln 19 - ln 31 - ln 32)	3,409,571,445			4 044 050 400
48 49	Transmission Plus: Transmission Plant-in-Service Additions (In 22)	(ln 20 + ln 21 - ln 33 - ln 34)	1,372,453,128 N/A			1,341,956,486 N/A
5 0	Plus: Additional Trans Plant on Transferred Assets (•	N/A			N/A
51	Plus: Additional Transmission Depreciation for 2013	•	N/A			N/A
52	Plus: Additional General & Intangible Depreciation fo		N/A			N/A
53	Plus: Additional Accum Deprec on Transferred Asset		N/A			N/A
54	Distribution	(ln 24 + ln 25 - ln 40 - ln 41)	2,022,953,454			- 0.405.040
55 56	General Plant Intangible Plant	(In 26 + In 27 - In 42 - In 43) (In 28 - In 44)	128,313,093 29,312,752			9,125,612 2,084,719
57	TOTAL NET PLANT IN SERVICE	(sum Ins 47 to 56)	6,962,603,871	NP(h)=	0.19435	1,353,166,818
		,	, , ,	()		, , ,
58	DEFERRED TAX ADJUSTMENTS TO RATE BASE	(Note D)				
59	Account No. 281.1 (enter negative)	(Worksheet B, In 2 & In 5.E)	(177,921,978)	NA		<u>-</u>
60 61	Account No. 282.1 (enter negative)	(Worksheet B, In 7 & In 10.E)	(1,191,929,058)	DA		(273,611,596)
61 62	Account No. 283.1 (enter negative) Account No. 190.1	(Worksheet B, In 12 & In 15.E) (Worksheet B, In 17 & In 20.E)	(432,760,567) 425,004,947	DA DA		(28,421,459) 49,949,881
63	Account No. 255 (enter negative)	(Worksheet B, In 24 & In 25.E)	(3,244,139)	DA		(778,649)
64	TOTAL ADJUSTMENTS	(sum Ins 59 to 63)	(1,380,850,795)		•	(252,861,822)
65	PLANT HELD FOR FUTURE USE	(Worksheet A In 29.E & In 30.E)	5,583,920	DA		1,912,346
66	REGULATORY ASSETS	(Worksheet A In 36. (E))	-	DA		-
67	WORKING CAPITAL	(Note E)				
68	Cash Working Capital	(1/8 * In 88)	3,978,581			3,896,836
69	Transmission Materials & Supplies	(Worksheet C, In 2.F)	1,134,751	TP	0.97945	1,111,436
70 71	A&G Materials & Supplies	(Worksheet C, In 3.F)	763,694	W/S CP(b)	0.07112	54,314
71 72	Stores Expense Prepayments (Account 165) - Labor Allocated	(Worksheet C, In 4.(D)) (Worksheet C, In 8.G)	- 199,491,970	GP(h) W/S	0.18700 0.07112	- 14,187,845
73	Prepayments (Account 165) - Cross Plant	(Worksheet C, In 8.F)	3,168,302	GP(h)	0.18700	592,478
74	Prepayments (Account 165) - Transmission Only	(Worksheet C, In 8.E)	18,110	DA	1.00000	18,110
75	Prepayments (Account 165) - Unallocable	(Worksheet C, In 8.D)	(197,401,389)	NA	0.00000	-
76	TOTAL WORKING CAPITAL	(sum Ins 68 to 75)	11,154,019			19,861,019
77	IPP CONTRIBUTIONS FOR CONSTRUCTION	(Note F) (Worksheet D, In 8 (B))	(2,406,767)	DA	1.00000	(2,406,767)
78	RATE BASE (sum Ins 57, 64, 65, 66, 76, 77)		5,596,084,248			1,119,671,594

APPALACHIAN POWER COMPANY

(1) (2) (3) (4)

	EXPENSE, TAXES, RETURN & REVENUE	Data Sources				Total
	REQUIREMENTS CALCULATION	(See "General Notes")	TO Total	Allo	<u>ocator</u>	<u>Transmission</u>
Line No.	OPERATION & MAINTENANCE EXPENSE					
79	Production	321.80.b	1,892,122,758			
80	Distribution	322.156.b	115,706,381			
81	Customer Related Expense	322.164,171,178.b	53,414,582			
82	Regional Marketing Expenses	322.131.b	5,904,349			
83	Transmission	321.112.b	64,421,229			
84	TOTAL O&M EXPENSES	(sum Ins 79 to 83)	2,131,569,299			
85 86	Less: Total Account 561	(Note G) (Worksheet F, In 15.C)	10,758,518			
86 87	Less: Account 565 Less: Regulatory Deferrals & Amortizations	(Note H) 321.96.b (Note I) (Worksheet F, In 4.C)	35,116,817 (13,282,753)			
88	Total O&M Allocable to Transmission	(Ins 83 - 85 - 86 - 87)	31,828,647	TP	0.97945	31,174,687
	rotal Cam, modable to Transmission	(30 30 31)	0.,020,0		0.070.0	0.,,00.
89	Administrative and General	323.197.b (Note J)	115,443,349			
90	Less: Acct. 924, Property Insurance	323.185.b	2,893,399			
91	Acct. 9260039 PBOP Expense	PBOP Worksheet O Line 9 & 10, (Note K)	10,321,493			
92	Acct. 9260057 PBOP Medicare Subsidy	PBOP Worksheet O Line 11, (Note K)	4 020 200			
93 94	PBOP Expense Billed From AEPSC Acct. 928, Reg. Com. Exp.	PBOP Worksheet O Line 13, (Note K) 323.189.b	1,038,300 2,048,123			
9 4 95	Acct. 926, Reg. Com. Exp. Acct. 930.1, Gen. Advert. Exp.	323.191.b	1,213,171			
96	Acct. 930.2, Misc. Gen. Exp.	323.192.b	6,334,522			
97	Balance of A & G	(In 89 - sum In 90 to In 96)	91,594,341	W/S	0.07112	6,514,179
98	Plus: Acct. 924, Property Insurance	(In 90)	2,893,399	GP(h)	0.18700	541,071
99	Acct. 928 - Transmission Specific	Worksheet F In 19.(E) (Note L)	· · · · -	TP ´	0.97520	-
100	Acct 930.1 - Only safety related ads -Direct	Worksheet F In 36.(E) (Note L)	-	TP	0.97520	-
101	Acct 930.2 - Misc Gen. Exp Trans	Worksheet F In 44.(E) (Note L)	785,229	DA	1.00000	785,229
102	Settlement Approved PBOP Recovery	PBOP Worksheet O, Col. C, Line 1, (Note M)	13,362,440	W/S	0.07112	950,335
103	A & G Subtotal	(sum Ins 97 to 102)	108,635,409			8,790,814
104	O & M EXPENSE SUBTOTAL	(ln 88 + ln 103)	140,464,056			39,965,501
104	Plus: TEA Settlement in Account 565	Company Records (Note H)	140,404,030	DA	1.00000	39,903,301
106	Plus: Transmission Lease Payments To Affiliates in A		-	DA	1.00000	_
107	TOTAL O & M EXPENSE	(ln 104 + ln 105 + ln 106)	140,464,056			39,965,501
108	DEPRECIATION AND AMORTIZATION EXPENSE	000 0 0 1	407.000.005	.	0.0000	
109	Production Distribution	336.2-6.f	167,860,265	NA	0.00000	-
110 111	Distribution Transmission	336.8.f 336.7.f	101,779,757 32,626,776	NA TP1	0.00000 0.98317	32,077,595
112	Plus: Transmission Plant-in-Service Additions (Works		N/A	1171	0.96517	52,077,595 N/A
113	General	336.10.f	3,140,253	W/S	0.07112	223,334
114	Intangible	336.1.f	16,715,020	W/S	0.07112	1,188,770
115	TOTAL DEPRECIATION AND AMORTIZATION	(Ln 109+110+	322,122,071		•	33,489,700
		111+112+113+114)				
116	TAXES OTHER THAN INCOME	(Note N)				
117	Labor Related	W 1 1 (111 00 (B)	0.000.404	14/10	0.07440	
118 119	Payroll Plant Related	Worksheet H In 23.(D)	8,830,131	W/S	0.07112	627,998
120	Property	Worksheet H In 23.(C) & In 58.(C)	50,923,379	DA		14,495,326
121	Gross Receipts/Sales & Use	Worksheet H In 23.(F)	33,724,260	NA NA	0.00000	-
122	Other	Worksheet H In 23.(E)	8,137,707	GP(h)	0.18700	1,521,766
123	TOTAL OTHER TAXES	(sum Ins 118 to 122)	101,615,477	· /	•	16,645,090
		(A) (A)				
124	INCOME TAXES	(Note O)	00.000/			
125	T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =		39.32%			
126 127	EIT=(T/(1-T)) * (1-(WCLTD/WACC)) = where WCLTD=(In 162) and WACC = (In 165)		41.31%			
128	and FIT, SIT & p are as given in Note O.					
129	GRCF=1 / (1 - T) = (from In 125)		1.6479			
130	Amortized Investment Tax Credit (enter negative)	(FF1 p.114, In 19.c)	(397,195)			
131	Income Tax Calculation	(ln 126 * ln 134)	187,179,555	ND/L	0.40405	37,451,121
132	ITC adjustment	(ln 129 * ln 130)	(654,530)	NP(h)	0.19435	(127,206)
133	TOTAL INCOME TAXES	(sum Ins 131 to 132)	186,525,025			37,323,915
134	RETURN ON RATE BASE (Rate Base*WACC)	(In 78 * In 165)	453,120,343			90,660,890
135	INTEREST ON IPP CONTRIBUTION FOR CONST. (No	te F) (Worksheet D, In 2.(B))	77,897	DA	1.00000	77,897
136	(Gains) / Losses on Sales of Plant Held for Future Use (Worksheet N, In 4, Cols. ((F) & (H))	-			-
137	Tax Impact on Net Loss / (Gain) on Sales of Plant Held	for Future Use (In 136 * In126)	-			-
120	TOTAL REVENUE REQUIREMENT	-	1,203,924,869			218 162 002
138	(sum Ins 107, 115, 123, 133, 134, 135)	-	1,203,324,008		•	218,162,992

APPALACHIAN POWER COMPANY

SUPPORTING CALCULATIONS

ln								
No.	TRANSMISSION PLANT INCLUDED IN PJM TARIFF							
139	Total transmission plant	(In 20)						1,991,143,960
140	Less transmission plant excluded from PJM Tariff (Note	P)						-
141	Less transmission plant included in OATT Ancillary Servi	ices (Worksheet A, In 23, Col.	(C)) (Note Q)					40,910,581
142	Transmission plant included in PJM Tariff	(In 139 - In 140 - In 141)						1,950,233,379
143	Percent of transmission plant in PJM Tariff	(In 142 / In 139)					TP	0.97945
				Payroll Billed from				
144	WAGES & SALARY ALLOCATOR (W/S)	(Note R)	Direct Payroll	AEP Service Corp.	Total			
145	Production	354.20.b	57,348,833	20,738,274	78,087,107	NA	0.00000	-
146	Transmission	354.21.b	4,649,255	5,848,397	10,497,652	TP	0.97945	10,281,964
147	Regional Market Expenses	354.22.b	0	0	-	NA	0.00000	-
148	Distribution	354.23.b	34,664,664	4,515,151	39,179,815	NA	0.00000	-
149	Other (Excludes A&G)	354.24,25,26.b	8,613,542	8,194,178	16,807,720	NA	0.00000	-
150	Total	(sum Ins 145 to 149)	105,276,294	39,296,000	144,572,294			10,281,964
151	Transmission related amount						W/S=	0.07112
152	WEIGHTED AVERAGE COST OF CAPITAL (WACC)							\$
152 153	WEIGHTED AVERAGE COST OF CAPITAL (WACC) Long Term Interest	(Worksheet M. In. 21, col. (E	())					
153	WEIGHTED AVERAGE COST OF CAPITAL (WACC) Long Term Interest Preferred Dividends	(Worksheet M, In. 21, col. (E (Worksheet M, In. 55, col. (E	,,					\$ 198,340,666 -
	Long Term Interest Preferred Dividends	(Worksheet M, In. 21, col. (E (Worksheet M, In. 55, col. (E	,,					198,340,666
153 154 155	Long Term Interest Preferred Dividends Development of Common Stock:	(Worksheet M, In. 55, col. (E	(i))					198,340,666 - Average
153 154	Long Term Interest Preferred Dividends	(Worksheet M, In. 55, col. (E) (Worksheet M, In. 1, col. (E))))					198,340,666
153 154 155 156	Long Term Interest Preferred Dividends Development of Common Stock: Proprietary Capital	(Worksheet M, In. 55, col. (E)))					198,340,666 - Average
153 154 155 156 157	Long Term Interest Preferred Dividends Development of Common Stock: Proprietary Capital Less: Preferred Stock	(Worksheet M, In. 55, col. (E) (Worksheet M, In. 1, col. (E) (Worksheet M, In. 2, col. (E))))					198,340,666 - Average 2,994,488,906
153 154 155 156 157 158	Long Term Interest Preferred Dividends Development of Common Stock: Proprietary Capital Less: Preferred Stock Less: Account 216.1	(Worksheet M, In. 55, col. (E) (Worksheet M, In. 1, col. (E) (Worksheet M, In. 2, col. (E) (Worksheet M, In. 3, col. (E))))))					198,340,666 - Average 2,994,488,906 - 1,632,577
153 154 155 156 157 158 159	Long Term Interest Preferred Dividends Development of Common Stock: Proprietary Capital Less: Preferred Stock Less: Account 216.1 Less: Account 219	(Worksheet M, In. 55, col. (E) (Worksheet M, In. 1, col. (E) (Worksheet M, In. 2, col. (E) (Worksheet M, In. 3, col. (E) (Worksheet M, In. 4, col. (E))))))	<u>Capital Structure</u>	Weighting		Cost	198,340,666 - Average 2,994,488,906 - 1,632,577 (44,220,373)
153 154 155 156 157 158 159	Long Term Interest Preferred Dividends Development of Common Stock: Proprietary Capital Less: Preferred Stock Less: Account 216.1 Less: Account 219	(Worksheet M, In. 55, col. (E) (Worksheet M, In. 1, col. (E) (Worksheet M, In. 2, col. (E) (Worksheet M, In. 3, col. (E) (Worksheet M, In. 4, col. (E))))))	<u>Capital Structure</u> Actual	<u>Weighting</u> Cap Limit		Cost (Note S)	198,340,666 - Average 2,994,488,906 - 1,632,577 (44,220,373)
153 154 155 156 157 158 159 160	Long Term Interest Preferred Dividends Development of Common Stock: Proprietary Capital Less: Preferred Stock Less: Account 216.1 Less: Account 219	(Worksheet M, In. 55, col. (E) (Worksheet M, In. 1, col. (E) (Worksheet M, In. 2, col. (E) (Worksheet M, In. 3, col. (E) (Worksheet M, In. 4, col. (E) (In 156 - In 157 - In 158 - In)))))					198,340,666 Average 2,994,488,906 - 1,632,577 (44,220,373) 3,037,076,702
153 154 155 156 157 158 159 160	Long Term Interest Preferred Dividends Development of Common Stock: Proprietary Capital Less: Preferred Stock Less: Account 216.1 Less: Account 219 Common Stock	(Worksheet M, In. 55, col. (E) (Worksheet M, In. 1, col. (E) (Worksheet M, In. 2, col. (E) (Worksheet M, In. 3, col. (E) (Worksheet M, In. 4, col. (E) (In 156 - In 157 - In 158 - In)))))	Actual	Cap Limit		(Note S)	198,340,666 Average 2,994,488,906 - 1,632,577 (44,220,373) 3,037,076,702 Weighted
153 154 155 156 157 158 159 160	Long Term Interest Preferred Dividends Development of Common Stock: Proprietary Capital Less: Preferred Stock Less: Account 216.1 Less: Account 219 Common Stock Long Term Debt (Note T) W/S M, In 11, In 22, col. (E))	(Worksheet M, In. 55, col. (E) (Worksheet M, In. 1, col. (E) (Worksheet M, In. 2, col. (E) (Worksheet M, In. 3, col. (E) (Worksheet M, In. 4, col. (E) (In 156 - In 157 - In 158 - In)))))	Actual 55.07%	Cap Limit 0.00%		(Note S)	198,340,666
153 154 155 156 157 158 159 160 161 162 163	Long Term Interest Preferred Dividends Development of Common Stock: Proprietary Capital Less: Preferred Stock Less: Account 216.1 Less: Account 219 Common Stock Long Term Debt (Note T) W/S M, In 11, In 22, col. (E)) Preferred Stock (In 157)	(Worksheet M, In. 55, col. (E) (Worksheet M, In. 1, col. (E) (Worksheet M, In. 2, col. (E) (Worksheet M, In. 3, col. (E) (Worksheet M, In. 4, col. (E) (In 156 - In 157 - In 158 - In Average \$ 3,722,145,904)))))	Actual 55.07% 0.00%	Cap Limit 0.00% 0.00%		(Note S) 0.0533	198,340,666 Average 2,994,488,906 - 1,632,577 (44,220,373) 3,037,076,702 Weighted 0.0293 0.0000

APPALACHIAN POWER COMPANY

<u>Notes</u>

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

A Revenue credits include:

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

See Worksheet E for details.

- B The annual and monthly net plant carrying charges on page 1 are used to compute the revenue requirement for RTEP sponsored upgrades or those projects receiving approved incentive-ROE's.
- C Transmission Plant balances in this study reflect the average of the balances at December 31, 2011 and December 31, 2012.
- The total-company balances shown for Accounts 281, 282, 283, 190 only reflect ADIT that relates to utility operations. The balance of Account 255 is reduced by prior flow throughs and is completely excluded if the utility chose to utilize amortization of tax credits against FIT expense. An exception to this is pre-1971 ITC balances, which are required to be taken as an offset to rate base. Account 281 is not allocated. In compliance with FERC Rulemaking RM02-7-000, Asset Retirement Obligation deferrals have been removed from ratebase. Transmission ADIT allocations are shown on WS B.

 The company will not include the ADIT portion of deferred hedge gains and losses in rate base.
- Cash Working Capital assigned to transmission is one-eighth of O&M allocated to transmission, as shown on line 88. It excludes:
 - 1) Load Scheduling & Dispatch Charges in account 561 that are collected in the OATT Ancilliary Services Revenue, as shown on line 85.
 - 2) AEP transmission equalization transfers, as shown on line 86
 - 3) The impact of state regulatory deferrals and amortizations, as shown on line 87
 - 4) All A&G Expenses, as shown on line 103.
- F Consistent with Paragraph 657 of Order 2003-A, the amount on line 77 is equal to the balance of IPP System Upgrade Credits owed to transmission customers that made contributions toward the construction of System upgrades, and includes accrued interest and unreturned balance of contributions. The annual interest expense is included on line 135.
- Removes from the cost of service the Load Scheduling and Dispatch expenses booked to accounts 561.1 through 561.8. Expenses recorded in these accounts, with the exception of 561.4 & 561.8 (lines 15 & 16 above) are recovered in Schedule 1A, OATT ancillary services rates. See Worksheet F, lines 6 through 15, for descriptions and the Form 1 Source of these accounts' balances.
- Removes cost of transmission service provided by others to determine the basis of cash working capital on line 88. To the extent such service is incurred to provide the PJM service at issue, e.g. transmission equalization agreement, such costs are added back on lines 105 and 106 to determine the total O&M collected in the formula. The amounts on lines 105 and 106 are also excluded in the calculation of the FCR percentage calculated on lines 5 through 11.

 The addbacks on lines 105 and 106 of activity recorded in 565 represents inter-company sales or purchases of transmission capacity necessary to meet each AEP company's transmission load relative to their available transmission capacity.
 - The company records referenced on lines 105 and 106 is the APPALACHIAN POWER COMPANY general ledger.
- I Removes the impact of state regulatory deferrals or their amortization from O&M expense.
- J General Plant and Administrative & General expenses, other than in accounts 924, 928, and 930, will be functionalized based on the Wages & Salaries "W/S" allocator. The allocation basis for accounts 924, 928 and 930 are separately presented in the formula. A change in the allocation method for an account must be approved via a 205 filing with the FERC.
- K These deductions on lines 91 through 93 are to remove from the cost of service the expenses recorded by the company for Postemployment Benefits Other than Pensions (PBOP). See Note M below for the recoverable PBOP expense.
- Expenses reported for these A&G accounts will be included in the cost of service only to the extent they are directly assignable to transmission service. Worksheet F allocates these expense items. Acct 928 Includes Regulatory Commission expenses itemized in FERC Form-1 at page 351, column H. FERC Assessment Fees and Annual Charges shall not be allocated to transmission. Only safety-related and educational advertising costs in Account 930.1 are included in the TCOS. Account 930.2 includes the expenses incurred by the transmission function for Associated Business Development revenues given as a credit to the TCOS on Worksheet E.
- M See note K above. Per the settlement in Docket ER08-1329, recoverable PBOP expense is based on an annual total for the operating companies that is ratioed to them based on the total of actual annual PBOP costs, including charges from the AEP Service Corportation. The calculation of the recoverable amount for each company is shown on Worksheet O, and the process for updating the annual total is documented on Attachment F, Allowable PBOP Expense Formula.
- N Includes only FICA, unemployment, highway, property and other assessments charged in the current year. Gross receipts, sales & use and taxes related to income are excluded.
- The currently effective income tax rate, where FIT is the Federal income tax rate; SIT is the State income tax rate, and p = the percentage of federal income tax deductible for state income taxes. See Worksheet G for the development of the Company's composite SIT. A utility that elected to utilize amortization of tax credits against taxable income, rather than book tax credits to Account No. 255 and reduce rate base, must reduce its income tax expense by the amount of the Amortized Investment Tax Credit (Form 1, 266.8.f)

(In 130) multiplied by (1/1-T) . If the applicable tax rates are zero enter 0.

Inputs Required: FIT = 35.00%

SIT= 6.64% (State Income Tax Rate or Composite SIT. Worksheet G))
p = 0.00% (percent of federal income tax deductible for state purposes)

- P Removes plant excluded from the OATT because it does not meet the PJM's definition of Transmission Facilities or is otherwise ineligible to be recovered under the OATT.
- Q Removes transmission plant (e.g. step-up transformers) included in the development of OATT ancillary service rates and not already removed for reasons indicated in Note P.
- R Includes functional wages & salaries billed by AEP Service Corporation for support of the operating company.
- Long Term Debt cost rate = long-term interest (ln 153) /average long term debt (ln 162). Preferred Stock cost rate = preferred dividends (ln 154) / preferred outstanding (ln 163). Common Stock cost rate (ROE) = 11.49%, the rate accepted by FERC in Docket No. ER08-1329. It includes an additional 50 basis points for PJM RTO membership. Interest expense for the true-up WACC is based on actual expenses for the true-up year. The amount of eligible hedging gains or losses included in total interest expense is limited to five basis points of the true-up capital structure. Details and calculations of the true-up weighted average cost of capital are shown on Worksheet M. Eligible Hedging Gains and Losses are defined in the Formula Protocols in the tariff, and on Worksheet M.
- T This note only applies to Indiana Michigan Power Company.
- Per Settlement, equity for APPALACHIAN POWER COMPANY is limited to 100% of Capital Structure. If the percentage of equity exceeds the cap, the excess is included in weighted percentage of long term debt in the capital structure.

 During the period ended December 31, 2011 the equity cap is in effect. During this period, a change in the cap percentage must be approved via a 205 filing with the FERC.

AEP East Companies Cost of Service Formula Rate Using 2012 FF1 Balances Worksheet A Supporting Plant Balances APPALACHIAN POWER COMPANY

<u>Line</u>	(A)	(B)	(C)	(D)	(E)
 Number	Rate Base Item & Supporting Balance	Source of Data	Balance @ December Ba	<u>31, 2011</u>	Average Balance for 2012
NOTE: Fund	tional ARO investment and accumulated depreciation	balances shown below are included in the total fur			
Plant Investr	nent Balances				
1	Production Plant In Service	FF1, page 205 Col.(g) & pg. 204 Col. (b), ln 46	5,620,438,618	5,182,826,934	5,401,632,776
2	Production Asset Retirement Obligation (ARO)	FF1, page 205&204, Col.(g)&(b), Ins 15,24,34,44	71,986,517	67,928,373	69,957,445
3	Transmission Plant In Service	FF1, page 207 Col.(g) & pg. 206 Col. (b), ln 58	2,040,266,144	1,942,021,775	1,991,143,960
4	Transmission Asset Retirement Obligation	FF1, page 207 Col.(g) & pg. 206 Col. (b), ln 57	-	-	-
5	Distribution Plant In Service	FF1, page 207 Col.(g) & pg. 206 Col. (b), ln 75	2,988,920,393	2,841,967,051	2,915,443,722
6	Distribution Asset Retirement Obligation	FF1, page 207 Col.(g) & pg. 206 Col. (b), ln 74	3,069	3,069	3,069
7	General Plant In Service	FF1, page 207 Col.(g) & pg. 206 Col. (b), ln 99	195,239,795	188,962,248	192,101,022
8	General Asset Retirement Obligation	FF1, page 207 Col.(g) & pg. 206 Col. (b), ln 98	811,747	811,747	811,747
9	Intangible Plant In Service	FF1, page 205 Col.(g) & pg. 204 Col. (b), ln 5	123,626,312	109,249,193	116,437,753
10	Total Property Investment Balance	(Sum of Lines: 3, 1, 5, 7, 9)	10,968,491,262	10,265,027,201	10,616,759,232
11	Total ARO Balance (included in total on line 10)	(Sum of Lines: 4, 2, 6, 8)	72,801,333	68,743,189	70,772,261
Accumulated	I Depreciation & Amortization Balances				
12	Production Accumulated Depreciation	FF1, page 219, Ins 20-24, Col. (b)	2,022,105,333	1,878,949,799	1,950,527,566
13	Production ARO Accumulated Depreciation	Company Records - Note 1	30,813,283	26,034,077	28,423,680
14	Transmission Accumulated Depreciation	FF1, page 219, ln 25, Col. (b)	629,801,174	607,580,490	618,690,832
15	Transmission ARO Accumulated Depreciation	Company Records - Note 1	-	-	-
16	Distribution Accumulated Depreciation	FF1, page 219, ln 26, Col. (b)	918,499,290	866,478,073	892,488,682
17	Distribution ARO Accumulated Depreciation	Company Records - Note 1	1,517	1,448	1,482
18	General Accumulated Depreciation	FF1, page 219, ln 28, Col. (b)	63,986,336	62,827,573	63,406,955
19	General ARO Accumulated Depreciation	Company Records - Note 1	594,444	267,102	430,773
20	Intangible Accumulated Amortization	FF1, page 200, ln 21, Col. (b)	91,986,512	82,263,489	87,125,001
21	Total Accumulated Depreciation or Amortization	(Sum of Lines: 14, 12, 16, 18, 20)	3,726,378,645	3,498,099,424	3,612,239,035
22	Total ARO Balance (included in total on line 21)	(Sum of Lines: 15, 13, 17, 19)	31,409,243	26,302,627	28,855,935
Generation S	Step-Up Units				
23	GSU Investment Amount	Company Records - Note 1	50,601,219	31,219,942	40,910,581
24	GSU Accumulated Depreciation	Company Records - Note 1	11,054,926	9,772,952	10,413,939
25	GSU Net Balance	(Line 23 - Line 24)	39,546,292	21,446,990	30,496,641
<u>Transmissio</u>	n Accumulated Depreciation Net of GSU Accumulated	<u>Depreciation</u>			
26	Transmission Accumulated Depreciation	(Line 14 Above)	629,801,174	607,580,490	618,690,832
27	Less: GSU Accumulated Depreciation	(Line 24 Above)	11,054,926	9,772,952	10,413,939
28	Subtotal of Transmission Net of GSU	(Line 26 - Line 27)	618,746,248	597,807,538	608,276,893
Plant Held Fo	or Future Use				
29	Plant Held For Future Use	FF1, page 214, ln 47, Col. (d)	5,319,071	5,848,769	5,583,920
30	Transmission Plant Held For Future	Company Records - Note 1	1,877,675	1,947,017	1,912,346
Regulatory A	Assets and Liabilities Approved for Recovery In Rateba				
31 32 33 34	Trate: Tragalatory / tabata a Elastimas call of thy be interes	ioa in ratozaco paroaani to a 250 milig mili tilo i 2110.			- - - -
35 36	Total Regulatory Deferrals Included in Ratebase		-	-	-

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

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

AEP East Companies Cost of Service Formula Rate Using 2012 FF1 Balances Worksheet B Supporting ADIT and ITC Balances APPALACHIAN POWER COMPANY

	(A)	(B)	(C)	(D)	(E)
<u>Line</u> Number	<u>Description</u>	<u>Source</u>	Balance @ December 31, 2012	Balance @ December 31, 2011	Average Balance for 2012
1	Account 281				
2 3 4	Year End Utility Deferrals Less: ARO Related Deferrals Less: Other Excluded Deferrals	FF1, p. 272 - 273, ln 8, Col. (k) Company Records - Note 1 Company Records - Note 1	197,320,252 - 197,320,252	158,523,703 - 158,523,703	177,921,978 - 177,921,978
5	Transmission Related Deferrals	Ln 2 - ln 3 - ln 4		-	-
6	Account 282				
7 8 9 10	Year End Utility Deferrals Less: ARO Related Deferrals Less: Other Excluded Deferrals Transmission Related Deferrals	FF1, p. 274 - 275, ln 5, Col. (k) Company Records - Note 1 Company Records - Note 1 Ln 7 - ln 8 - ln 9	1,229,418,143 5,314,689 934,642,332 289,461,122	1,154,439,973 15,371,558 881,306,346 257,762,069	1,191,929,058 10,343,124 907,974,339 273,611,596
11	Account 283				
12 13 14 15	Year End Utility Deferrals Less: ARO Related Deferrals Less: Other Excluded Deferrals Transmission Related Deferrals	FF1, p. 276 - 277, ln 9, Col. (k) Company Records - Note 1 Company Records - Note 1 Ln 12 - ln 13 - ln 14	431,851,994 2,971,021 398,636,251 30,244,723	433,669,140 3,683,424 403,387,521 26,598,196	432,760,567 3,327,223 401,011,886 28,421,459
16	Account 190				
17 18 19 20	Year End Utility Deferrals Less: ARO Related Deferrals Less: Other Excluded Deferrals Transmission Related Deferrals	FF1, p. 234, ln 8, Col. (c) Company Records - Note 1 Company Records - Note 1 Ln 17 - ln 18 - ln 19	399,990,470 40,515,848 309,230,321 50,244,301	450,019,423 40,164,641 360,199,321 49,655,461	425,004,947 40,340,245 334,714,821 49,949,881
21	Account 255				
22 23	Year End ITC Balances Less: Balances Not Qualified for Ratebase	FF1, p. 266-267, ln 8, Col. (h) Company Records - Note 1	3,205,027 382,363	4,445,172 779,558	3,825,100 580,961
24 25	ITC Balances Includeable Ratebase Transmission Related Deferrals	Ln 22 - In 23 Company Records - Note 1	2,822,664 641,429	3,665,614 915,869	3,244,139 778,649

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

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

AEP East Companies Cost of Service Formula Rate Using 2012 FF1 Balances Worksheet C Supporting Working Capital Rate Base Adjustments APPALACHIAN POWER COMPANY

(A) (B) (C) (F) (G) (H) (I)

Materials & Supplies

<u>Line</u> Number		<u>Source</u>	Balance @ December 31, 2012	Balance @ December 31, 2011	Average Balance for 2012
1					
2	Transmission Materials & Supplies	FF1, p. 227, In 8, Col. (c) & (b)	1,508,480	761,022	1,134,751
3	General Materials & Supplies	FF1, p. 227, ln 11, Col. (c) & (b)	825,807	701,580	763,694
4	Stores Expense (Undistributed)	FF1, p. 227, ln 16, Col. (c) & (b)	0	0	-

		<u>Prepayment</u>	Balance Summar	У			
5		Average of YE Balance	Excludable <u>Balances</u>	100% Transmission <u>Related</u>	Transmission Plant <u>Related</u>	Transmission Labor <u>Related</u>	Total Included in Ratebase (E)+(F)+(G)
6	Totals as of December 31, 2012	5,331,711	(201,506,924)	12,816	3,057,772	203,768,047	206,838,635
7	Totals as of December 31, 2011	5,222,276	(193,295,853)	23,404	3,278,832	195,215,893	198,518,129
8	Average Balance	5,276,994	(197,401,389)	18,110	3,168,302	199,491,970	202,678,382

Prepayments Account 165 - Balance @ 12/31/2012

9	Acc. No.	<u>Description</u>	2012 YE Balance	Excludable Balances	100% Transmission <u>Related</u>	Transmission Plant <u>Related</u>	Transmission Labor <u>Related</u>	Total Included in Ratebase (E)+(F)+(G)	<u>Explanation</u>
10	1650001	Prepaid Insurance	1,844,047	-		1,844,047		1,844,047	Plant Related Insurance Policies
11	165000212	Prepaid Taxes	1,809,578	1,809,578		-		-	Prepaid Taxes
12	1650003	Prepaid Rents	0	-			-	-	Prepaid Distribution Rent Expense
13	1650004	Prepaid Interest	26,938	26,938				-	
14	1650005	Prepaid Employee Benefits	0	-			-	-	
15	1650006	Other Prepayments	12,816	-	12,816	-		12,816	PPD Sales
16	1650009	Prepaid Carry Cost-Factored AR	62,549	62,549				-	AR Factoring - Retail Only
17	1650010	Prepaid Pension Benefits	203,768,047				203,768,047	203,768,047	Prefunded Pension Expense
18	1650014	FAS 158 Qual Contra Asset	(203,768,047)	(203,768,047)				-	SFAS 158 Offset
19	1650016	FAS 112 ASSETS	0	-			-	-	SFAS 112 Overfunding Asset
20	1650021	Prepaid Insurance - EIS	1,213,725	-		1,213,725		1,213,725	
21	1650023	Prepaid Lease	361,859	361,859				-	
22	165001112	Prepaid Sales Taxes	199	199				-	
									_
		Subtotal - Form 1, p 111.57.c	5,331,711	(201,506,924)	12,816	3,057,772	203,768,047	206,838,635	-

Prepayments Account 165 - Balance @ 12/31/ 2011

22	Acc. No.	<u>Description</u>	2011 <u>YE Balance</u>	Excludable <u>Balances</u>	100% Transmission <u>Related</u>	Transmission Plant <u>Related</u>	Transmission Labor <u>Related</u>	Total Included in Ratebase (E)+(F)+(G)	<u>Explanation</u>
23	1650001	Prepaid Insurance	1,935,794			1,935,794		1,935,794	Plant Related Insurance Policies
24	165000211	Prepaid Taxes	1,637,001	1,637,001		0		-	Prepaid Taxes
25	1650003	Prepaid Rents	0	0				-	Prepaid Distribution Rent Expense
26	1650004	Prepaid Interest	27,220	27,220				-	
27	1650005	Prepaid Employee Benefits	0						
28	1650006	Other Prepayments	23,404		23,404	0		23,404	PPD Sales
29	1650009	Prepaid Carry Cost-Factored AR	49,321	49,321				-	AR Factoring - Retail Only
30	1650010	Prepaid Pension Benefits	195,215,893				195,215,893	195,215,893	Prefunded Pension Expense
31	1650014	FAS 158 Qual Contra Asset	(195,215,893)	(195,215,893)				-	SFAS 158 Offset
32	1650016	FAS 112 ASSETS	0	0				-	SFAS 112 Overfunding Asset
33	1650021	Prepaid Insurance - EIS	1,343,038			1,343,038		1,343,038	
34	1650023	Prepaid Lease	206,498	206,498					
									_
		Subtotal - Form 1, p 111.57.d	5,222,276	(193,295,853)	23,404	3,278,832	195,215,893	198,518,129	-

AEP East Companies Cost of Service Formula Rate Using 2012 FF1 Balances Worksheet D Supporting IPP Credits APPALACHIAN POWER COMPANY

<u>Line</u> <u>Number</u>	(A) <u>Description</u>	(B) <u>2012</u>
1	Net Funds from IPP Customers 12/31/2011 (2012 FORM 1, P269, line 20.b)	(2,367,818.00)
2	Interest Accrual (Company Records - Note 1)	(77,897.00)
3	Revenue Credits to Generators (Company Records - Note 1)	-
4 5 6	Other Adjustments Accounting Adjustment (Company Records - Note 1)	
7	Net Funds from IPP Customers 12/31/2012 (2012 FORM 1, P269, line 23.f)	(2,445,715.00)
8	Average Balance for Year as Indicated in Column ((In 1 + In 7)/2)	(2,406,766.50)
Note 1	On this worksheet Company Records refers to APPALACHIAN	

Note 1 On this worksheet Company Records refers to APPALACHIAN POWER COMPANY's general ledger.

AEP East Companies Cost of Service Formula Rate Using 2012 FF1 Balances Worksheet E Supporting Revenue Credits APPALACHIAN POWER COMPANY

<u>Line</u> Number	<u>Description</u>	<u>Total</u> <u>Company</u>	Non- Transmission	<u>Transmission</u>
1	Account 450, Forfeited Discounts (FF1 p.300.16.(b); Company Records - Note 1)	5,024,400	5,024,400	-
2	Account 451, Miscellaneous Service Revenues (FF1 p.300.17.(b); Company Records - Note 1)	1,833,084	1,470,159	362,925
3	Account 454, Rent from Electric Property (FF1 p.300.19.(b); Company Records - Note 1)	21,091,928	19,091,646	2,000,282
4	Account 4560015, Associated Business Development - (Company Records - Note 1)	7,744,030	6,488,501	1,255,529
5	Account 456 - Other Electric Revenues - (Company Records - Note 1)	59,627,918	59,627,918	-
6	Subtotal - Other Operating Revenues (Company Total equals (FF1 p. 300.26.(b))	95,321,360	91,702,624	3,618,736
7	Accounts 4470004 & 5, Revenues from Grandfathered Transmission Contracts -	-	-	
8	(Company Records - Note 1) Total Other Operating Revenues To Reduce Revenue Requirement	95,321,360	91,702,624	3,618,736

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

AEP East Companies Cost of Service Formula Rate Using 2012 FF1 Balances Worksheet F Supporting Allocation of Specific O&M or A&G Expenses APPALACHIAN POWER COMPANY

	(A)	(B)	(C)	(D)	(E)	(F)
<u>Line</u>			<u>2012</u>	<u>100%</u>	100% Transmission	
<u>Number</u>	<u>ltem No.</u>	<u>Description</u>	<u>Expense</u>	Non-Transmission	<u>Specific</u>	<u>Explanation</u>
		Regulatory O&M Deferrals & Amortizations				
1	5700005	Maint Station-Reliability-Df	15,744			
2	5660007	Virginia T-RAC UnderRecovery	(13,438,947)			
3	5660000	Amortization Severance	140,450			
4 5		Total	\$ (13,282,753)			
3			ψ (13,202,133)			
		Detail of Account 561 Per FERC Form 1				
6	FF1 p 321.84.b	561 - Load Dispatching	0			
7	FF1 p 321.85.b	561.1 - Load Dispatch - Reliability	23,193			
8	FF1 p 321.86.b	561.2 - Load Dispatch - Monitor & Operate Trans System	3,210,973			
9	FF1 p 321.87.b	561.3 - Load Dispatch - Trans Service & Scheduling	(314)			
10	FF1 p 321.88.b	561.4 - Scheduling, System Control & Dispatch	5,714,454			
11 12	FF1 p 321.89.b FF1 p 321.90.b	561.5 - Reliability, Planning and Standards Development 561.6 - Transmission Service Studies	598,508			
13	FF1 p 321.90.b	561.7 - Generation Interconnection Studies	0			
14	FF1 p 321.91.b	561.8 - Reliability, Planning and Standards Development Services	1,211,704			
15	FFT p 321.92.0	Total of Account 561	10,758,518			
10		Total of Acodum oo i	10,700,010			
		Account 928				
16	9280000	Regulatory Commission Exp	2,443	2,443	-	
17 18	9280001	Regulatory Commission Exp-Adm	1,473,176	1,473,176	-	
10	9280002	Regulatory Commission Exp-Case	572,503	572,503	-	
19		Total	2,048,123	2,048,123		
				_,; ; ; ; ; ; ;		
20	0201000	Account 930.1	67.020	67,000		
20 21	9301000 9301001	General Advertising Expenses Newspaper Advertising Space	67,832 244,076	67,832 244,076	-	
22	9301001	Radio Station Advertising Time	4,902	4,902		
23	9301003	TV Station Advertising Time	565,322	565,322	_	
24	9301004	Newspaper Advertising Prod Exp	1,752	1,752		
25	9301005	Radio &TV Advertising Prod Exp	36,525	36,525	-	
26	9301006	Spec Corporate Comm Info Proj	2	2	-	
27	9301007	Special Adv Space & Prod Exp	345	345	-	
28	9301008	Direct Mail and Handouts	-	•	-	
29	9301009	Fairs, Shows, and Exhibits	269	269	-	
30 31	9301010 9301011	Publicity Pedications Tours & Openings	21,223	21,223 5	-	
31 32	9301011	Dedications, Tours, & Openings Public Opinion Surveys	13,839	13,839	-	
33	9301012	Movies Slide Films & Speeches	10,009	10,009	-	
34	9301014	Video Communications	77	77	-	
35	9301015	Other Corporate Comm Exp	257,000	257,000	-	
36		Total	1,213,171	1,213,171		
00			1,210,171	1,210,171		
27	0202000	Account 930.2	000.004	000.004		
37 38	9302000 9302003	Misc General Expenses Corporate & Fiscal Expenses	822,994 132,749			
38 39	9302003	Research, Develop&Demonstr Exp	132,749			
40	9302004	Assoc Bus Dev - Materials Sold	1,970,687			
41	9302007	Assoc Business Development Exp	3,393,929		785,229	
43	9302458	Non Affiliated Expense	638		. 23,220	
44		Total	6,334,522	5,549,293	785,229	
44		I Otal	0,334,322	5,549,293	100,229	

AEP East Companies

Cost of Service Formula Rate Using 2012 FF1 Balances Worksheet G Supporting - Development of Composite State Income Tax Rate APPALACHIAN POWER COMPANY

Tennessee Income Tax Rate Apportionment Factor - Note 2	6.50% 1.98%	
Effective State Tax Rate		0.13%
West Virginia Net Income Tax Rate	7.75%	
Apportionment Factor - Note 2	52.71%	
Effective State Tax Rate		4.08%
Virginia Income Tax Rate	6.00%	
Apportionment Factor - Note 2	37.41%	
Effective State Tax Rate		2.24%
Michigan Business Income Tax Rate	6.00%	
Apportionment Factor - Note 2	0.11%	
Effective State Tax Rate		0.01%
Ohio Franchise Tax Rate	0.00%	
Phase-out Factor Note 1	0.00%	
Apportionment Factor - Note 2	0.00%	/
Effective State Tax Rate		0.00%
Illinios Corporate Income Tax Rate	9.50%	
Apportionment Factor - Note 2	1.94%	
Effective State Tax Rate		0.18%
Total Effective State Income Tax Rate		6.64%

Note 2 Apportionment Factors are determined as part of the Company's annual tax return for that jurisdiction.

Note 1 The Ohio State Income Tax is being phased-out prorata over a 5 year period from 2005 through 2009. The taxable portion of income is 0% 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 Activites Tax that is included in Schedule H and H-1

AEP East Companies Cost of Service Formula Rate Using 2012 FF1 Balances Worksheet H Supporting Taxes Other than Income APPALACHIAN POWER COMPANY

(A) (B) (D) (E) (C) (F) Line Total No. Account Company **Property** Labor Other Non-Allocable NOTE 1 **Revenue Taxes Gross Receipts Tax** 13,315,273 13,315,273 Real Estate and Personal Property Taxes Real and Personal Property - West Virginia 34,549,317 34,549,317 Real and Personal Property - Virginia 15,173,148 15,173,148 Real and Personal Property - Tennessee 734,598 734,598 Real and Personal Property - Other Jurisdictions 466,316 466,316 Payroll Taxes 8 9 Federal Insurance Contribution (FICA) 8,566,234 8,566,234 Federal Unemployment Tax 27,378 27,378 236,519 236,519 State Unemployment Insurance 12 **Production Taxes** 13 State Severance Taxes Miscellaneous Taxes State Business & Occupation Tax 20,401,461 20,401,461 State Public Service Commission Fees 4,616,176 4,616,176 17 State Franchise Taxes 3,519,086 3,519,086 1,899 1,899 State Lic/Registration Fee 546 546 19 Misc. State and Local Tax 20 Sales & Use 540 540 6,986 Federal Excise Tax 6,986 Michigan Single Business Tax 8,830,131 33,724,260 101,615,477 50,923,379 8,137,707 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 **General** <u>Total</u> **Production** <u>Transmsission</u> **Distribution** 7,169,080,727 131,036,156 Functionalized Net Plant (Hist. TCOS, Lns 212 thru 222) 3,557,160,051 1,410,464,970 2,070,419,551 24 VIRGINIA JURISDICTION 14.60% 44.97% 55.78% Percentage of Plant in VIRGINIA JURISDICTION 51.49% Net Plant in VIRGINIA JURISDICTION (Ln 24 * Ln 25) 519,520,961 634,267,997 1,154,977,049 67,468,340 2,376,234,348 Less: Net Value of Exempted Generation Plant 126,497,409 27 393,023,552 634,267,997 1,154,977,049 67,468,340 28 Taxable Property Basis (Ln 26 - Ln 27) 2,249,736,939 29 100% Relative Valuation Factor 100% 100% 100% Weighted Net Plant (Ln 28 * Ln 29) 1,154,977,049 393,023,552 634,267,997 67,468,340 30 -100.00% 31 General Plant Allocator (Ln 30 / (Total - General Plant)) 18.01% 29.06% 52.93% (67,468,340) 12,150,955 19,609,414 Functionalized General Plant (Ln 31 * General Plant) 35,707,971 653,877,412 2,249,736,939 33 Weighted VIRGINIA JURISDICTION Plant (Ln 30 + 32) 405,174,507 1,190,685,020 Functional Percentage (Ln 33/Total Ln 33) 29.06% 18.01% 52.93% 4,410,017 2,732,663 8,030,468 15,173,148 Functionalized Expense in VIRGINIA JURISDICTION **WEST VA JURISDICTION** Percentage of Plant in WEST VA JURISDICTION 85.40% 51.89% 44.21% 48.34% 731,940,783 63,338,743 Net Plant in WEST VA JURISDICTION (Ln 24 * Ln 36) 3,037,639,090 915,410,634 4,748,329,251 38 Less: Net Value of Exempted Generation Plant 1,954,604,153 1,083,034,937 731,940,783 915,410,634 63,338,743 2,793,725,098 Taxable Property Basis (Ln 37 - Ln 38) 100% 100% 100% 100% 40 Relative Valuation Factor 731,940,783 63,338,743 1,083,034,937 915,410,634 41 Weighted Net Plant (Ln 39 * Ln 40) -100.00% General Plant Allocator (Ln 41 / (Total - General Plant)) 39.67% 26.81% 33.53% 25,123,943 16,979,359 21,235,441 (63,338,743)43 Functionalized General Plant (Ln 42 * General Plant) Weighted WEST VA JURISDICTION Plant (Ln 41 + 43) 1,108,158,880 748,920,142 936,646,075 2,793,725,098 39.67% 26.81% 33.53% Functional Percentage (Ln 44/Total Ln 44) 11,583,274 13,704,331 9,261,713 34,549,317 Functionalized Expense in WEST VA JURISDICTION TENNESSEE JURISDICTION Net Plant in TENNESSEE JURISDICTION (Ln 24 - Ln 26 - Ln 37 44,256,189 31,867 229,072 44,517,128 Less: Net Value Exempted Generation Plant 44,256,189 31,867 49 **Taxable Property Basis** 229,072 44,517,128 50 Relative Valuation Factor 100% 100% 100% 100% 44,256,189 229,072 51 Weighted Net Plant (Ln 49 * Ln 50) 31,867 General Plant Allocator (Ln 51 / (Total - General Plant) 0.00% -100.00% 52 99.93% 0.07% (229,072) Functionalized General Plant (Ln 53 * General Plant) 228,907 165 44,485,096 54 32,032 44,517,128 Weighted TENNESSEE JURISDICTION Plant (Ln 51 + 53) 0.07% 55 Functional Percentage (Ln 54/Total Ln 54) 0.00% 99.93% 734,598 734,069 529 Functionalized Expense in TENNESSEE JURISDICTION 466,316 Total Other Jurisdictions: (Line 7 * Net Plant Allocator) 89,526 16,436,994 14,495,326 19,614,270 50,923,379 Total Func. Property Taxes (Sum Lns 35, 46 56, 57)

AEP East Companies Cost of Service Formula Rate Using 2012 FF1 Balances Worksheet H-1 Form 1 Source Reference of Company Amounts on WS H APPALACHIAN POWER COMPANY

	(A)	(B)	(C)	(D)
Line No.	Annual Tax Expenses by Type (Note 1)	Total Company	FERC FORM 1 Tie-Back	FERC FORM 1 Reference
1	Revenue Taxes	Company	Tic-Dack	T ENOT ON THE TRETERIOR
2	Gross Receipts Tax	13,315,273	12,477,550	P.263.1 ln 4 (i)
			145,133	P.263.1 ln 33 (i)
			692,590	P.263.1 In 34 (i)
3 4	Real Estate and Personal Property Taxes Real and Personal Property - West Virginia	34,549,317		
			16,414,766 18,184,510	P.263 ln 34 (i) P.263 ln 35 (i)
			(82,556) (28,406)	P.263 ln 38 (i) P.263 ln 39 (i)
			61,003	P.263 ln 40 (i)
5	Real and Personal Property - Virginia	15,173,148		
			23 191	P.263.2 ln 22 (i) P.263.2 ln 23 (i)
			(29,546) 14,980,441	P.263.2 ln 24 (i) P.263.2 ln 25 (i)
			(2,240)	P.263.2 ln 29 (i)
			(100,722) 325,001	P.263.2 ln 30 (i) P.263.2 ln 31 (i)
6	Real and Personal Property - Tennessee	734,598		
J	real and reporty remiesses	701,000	(64,602)	P.263.3 ln 10 (i)
7	Real and Personal Property - Other Jurisdictions	466,316	799,200	P.263.3 In 11 (i)
			704 465,612	P.263.1 ln 36 (i) P.263.1 ln 37 (i)
8 9	Payroll Taxes Federal Insurance Contribution (FICA)	8,566,234		
10	Federal Unemployment Tax	27,378	8,566,234	P.263 In 6 (i)
11	State Unemployment Insurance	236,519	27,378	P.263 In 9 (i)
		ŕ	111,767 14,244	P.263.1 ln 17 (i) P.263.1 ln 40 (i)
			110,391 117	P.263.2 ln 38 (i) P.263.3 ln 22 (i)
12 13	Production Taxes State Severance Taxes		117	1 .200.3 111 22 (1)
		-	-	
14 15	Miscellaneous Taxes State Business & Occupation Tax	20,401,461		
			390,088 19,769,873	P.263 In 21 (i) P.263 In 22 (i)
16	State Public Service Commission Fees	4,616,176	241,500	P.263 In 23 (i)
10	State Fublic Service Commission rees	4,010,170	1,599,615	P.263 In 26 (i)
			3,016,561	P.263 In 27 (i)
17	State Franchise Taxes	3,519,086	(266,239)	P.263.1 In 20 (i)
			282,774 (322,867)	P.263.1 In 21 (i) P.263.1 In 23 (i)
			(25,537)	P.263.1 In 25 (i)
			89,833	P.263.1 In 26 (i)
			6,672,000 (2,897,155)	P.263.2 In 11 (i) P.263.2 In 10 (i)
			(41,712)	P.263.3 In 5 (i)
			14,876 13,113	P.263.3 In 6 (i) P.263.3 In 7 (i)
18	State Lic/Registration Fee	1,899	,	(1)
10	Cate Lie/Negionanon i GG	1,033	25 1.700	P.263.1 In 10 (i)
			1,700 22	P.263.2 In 13 (i) P.263.3 In 14 (i)
			52 100	P.263.4 In 25 (i)
19	Misc. State and Local Tax	546		P.263.3 In 26 (i)
20	Sales & Use	540	546	P.263.1 ln 8 (i)
			688 1,172	P.263 In 30 (i) P.263 In 31(i)
			(583) 24	P.263.1 In 32(i) P.263.2 In 16 (i)
21	Federal Excise Tax	6,986	(761)	P.263.2 In 17 (i)
		0,980	6,986	P.263 In 14 (i)
22	Michigan Single Business Tax	-	-	
23	Total Taxes by Allocable Basis	101,615,477	101,615,477	
	(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 2012 FF1 Balances Worksheet I Supporting Transmission Plant in Service Additions APPALACHIAN POWER COMPANY

/ A \	/ R \	(C)	(D)	/ E \	/ E \	(G)	(H)	(1)
(Δ)	(0)	(0)	(0)	(-)	(i <i>)</i>	(6)	(11)	(1)

I. Calculation of Composite Depreciation Rate

1	Transmission Plant @ Beginning of Historic Period (2012) (P.206, In 58,(b)):	1,942,021,775
2	Transmission Plant @ End of Historic Period (2012) (P.207, In 58,(g)):	2,040,266,144
3		3,982,287,919
4	Average Balance of Transmission Investment	1,991,143,960
5	Annual Depreciation Expense, Historic TCOS, In 276	32,626,776
6	Composite Depreciation Rate	1.64%
7	Round to 1.64% to Reflect a Composite Life of 61 Years	1.64%

II. Calculation of Property Placed in Service by Month and the Related Depreciation Expense

8	Month in Service	Сар	italized Balance	Composite Annual Depreciation Rate	De	Annual epreciation	Mc	onthly Depreciation	No. Months Depreciation	First Year Depreciation Expense
9	January	\$	71,997,178	1.64%	\$	1,180,754	\$	98,396	11	\$ 1,082,356
10	February	\$	5,649,481	1.64%	•	92,651	\$	7,721	10	77,210
11	March	\$	4,359,926	1.64%	\$	71,503	\$	5,959		\$ 53,631
12	April	\$	3,540,020	1.64%	\$	58,056	\$	4,838		\$ 38,704
13	May	\$	2,897,989	1.64%	\$	47,527	\$	3,961	7	\$ 27,727
14	June	\$	5,135,780	1.64%	\$	84,227	\$	7,019	6	\$ 42,114
15	July	\$	29,357,907	1.64%	\$	481,470	\$	40,122	5	\$ 200,610
16	August	\$	4,600,335	1.64%	\$	75,445	\$	6,287	4	\$ 25,148
17	September	\$	2,149,084	1.64%	\$	35,245	\$	2,937	3	\$ 8,811
18	October	\$	1,559,798	1.64%	\$	25,581	\$	2,132	2	\$ 4,264
19	November	\$	1,547,549	1.64%	\$	25,380	\$	2,115	1	\$ 2,115
20	December	\$	8,029,318	1.64%	\$	131,681	\$	10,973	0	\$ -
21	Investment	\$	140,824,365	•				Depr	eciation Expense	\$ 1,562,690

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 2013

		Estimated Cost	<u>Month in </u>
		(000's)	Service
25 Major Zonal Projects			
26 VIRGINIA SYS REHAB		\$5,558	Aug-13
27 Line Rehab/Replace		\$5,621	Dec-13
27 Line Renab/Replace	Subtotal	\$11,179	DC0 10
	Subiolai	φ11,179	
28 PJM Socialized/Beneficiary Allocated Regional Projects			
29		\$0	
30	Subtotal	\$0	
		T -	

AEP East Companies Cost of Service Formula Rate Using 2012 FF1 Balances Worksheet J Supporting Calculation of PROJECTED PJM RTEP Project Revenue Requirement Billed to Benefiting Zones APPALACHIAN POWER COMPANY

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

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

ROE w/o incentives (Projected TCOS, In 164)	11.49%
Project ROE Incentive Adder	<==ROE Adder Cannot Exceed 125 Basis Points
ROE with additional basis point incentive	11.49% <== ROE Including Incentives Cannot Exceed 12.74% Until July 1, 2012
Determine R (cost of long term debt, cost of preferred stock and equi	uity percentage is from the Projected TCOS, Ins 162 through164)

	<u>%</u>	<u>Cost</u>	Weighted cost
Long Term Debt	54.63%	5.14%	2.805%
Preferred Stock	0.00%	0.00%	0.000%
Common Stock	45.37%	11.49%	<u>5.213%</u>
		R =	8.018%

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

Rate Base (Projected TCOS, In 78)	1,237,984,496
R (from A. above)	8.018%
Return (Rate Base x R)	99,264,090

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

Return (from B. above)	99,264,090
Effective Tax Rate (Projected TCOS, In 126)	42.12%
Income Tax Calculation (Return x CIT)	41,810,070
ITC Adjustment	(125,661
Income Taxes	41,684,409

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, In 1)	232,463,494
T.E.A. & Lease Payments (Projected TCOS, Lns 105 & 106)	-
Return (Projected TCOS, In 134)	99,264,090
Income Taxes (Projected TCOS, In 133)	41,684,409
Annual Revenue Requirement, Less TEA Charges, Return and	Taxes 91,514,995

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

Annual Revenue Requirement, Less TEA Charges, Return and Taxes	91,514,995
Return (from I.B. above)	99,264,090
Income Taxes (from I.C. above)	41,684,409
Annual Revenue Requirement, with Basis Point ROE increase	232,463,494
Depreciation (Projected TCOS, In 111)	32,054,077
Annual Rev. Req, w/ Basis Point ROE increase, less Depreciation	200,409,417

C. Determine FCR with hypothetical basis point ROE increase.

Net Transmission Plant (Projected TCOS, In 48)	1,370,918,678
Annual Revenue Requirement, with Basis Point ROE increase	232,463,494
FCR with Basis Point increase in ROE	16.96%
Annual Rev. Req, w / Basis Point ROE increase, less Dep.	200,409,417
FCR with Basis Point ROE increase, less Depreciation	14.62%
FCR less Depreciation (Projected TCOS, In 9)	<u>13.45%</u>
Incremental FCR with Basis Point ROE increase, less Depreciation	1.17%

III. Calculation of Composite Depreciation Rate

Transmission Plant @ Beginning of Historic Period (2012) (P.206, In 58,(b)):	1,942,021,775
Transmission Plant @ End of Historic Period (2012) (P.207, In 58,(g)):	2,040,266,144
Subtotal	3,982,287,919
Average Transmission Plant Balance for 2012	1,991,143,960
Annual Depreciation Rate (Projected TCOS, In 111)	32,626,776
Composite Depreciation Rate	1.64%
Depreciable Life for Composite Depreciation Rate	61.03
Round to nearest whole year	61

SUMMARY OF PROJECTED ANNUAL RTEP REVENUE REQUIREMENTS								
		Rev Require	W Incentives	Incentive Amount	s			
PROJECTED YEAR	2013	1 956 928	1 956 928	\$ -				

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

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

A. Base Plan Facilities

Facilities receiving incentives accepted by FERC in Docket No.

(e.g. ER05-925-000)

Current Projected Year ARR

Current Projected Year ARR w/ Incentive

1,915,150

Current Projected Year ARR w/ Incentive

Current Projected Year ARR w/ Incentive

Current Projected Year Incentive ARR

DetailsInvestment13,798,879Current Year2013Service Year (yyyy)2008
Service Month (1-12)ROE increase accepted by FERC (Basis Points)-Service Month (1-12)6
FCR w/o incentives, less depreciation13.45%Useful life61
CIAC (Yes or No)FCR w/incentives approved for these facilities, less dep.13.45%CIAC (Yes or No)NoAnnual Depreciation Expense226,211

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.

CIAC (Yes or No)	INO	Annual Depreciation E	лрепве			226,211		LIFE OF THE P	NOSECT.		
Investment Year	Beginning Balance	Depreciation Expense	Ending Balance	RTEP Rev. Req't. w/o Incentives	RTEP Rev. Req't. with Incentives **	Incentive Rev. Requirement ##	Rev Prior	EP Projected v. Req't.From Year Template o Incentives		RTEP Projected Rev. Req't.From Prior Year Template with Incentives **	
2008	13,798,879	113,106	13,685,773	1,954,201	1,954,201	\$ -					
2009	13,685,773	226,211	13,459,562	2,036,875	2,036,875	\$ -	\$	1,124,469		\$ 1,124,469	
2010	13,459,562	226,211	13,233,351		2,006,444		•	2,027,403		\$ 2,027,403	
		-		2,006,444			Φ Φ				
2011	13,233,351	226,211	13,007,140	1,976,012			\$	2,050,107		\$ 2,050,107	
2012	13,007,140	226,211	12,780,929	1,945,581	1,945,581	\$ -	\$	1,906,118		\$ 1,906,118	
2013	12,780,929	226,211	12,554,718	1,915,150	1,915,150	\$ -					
2014	12,554,718	226,211	12,328,507	1,884,718	1,884,718						
		-									
2015	12,328,507	226,211	12,102,296	1,854,287	1,854,287						
2016	12,102,296	226,211	11,876,084	1,823,856	1,823,856	\$ -					
2017	11,876,084	226,211	11,649,873	1,793,424	1,793,424	\$ -					
2018	11,649,873	226,211	11,423,662	1,762,993	1,762,993						
2019	11,423,662	226,211	11,197,451	1,732,562	1,732,562						
2020	11,197,451	226,211	10,971,240	1,702,130							
2021	10,971,240	226,211	10,745,029	1,671,699	1,671,699	\$ -					
2022	10,745,029	226,211	10,518,818	1,641,268	1,641,268	\$ -					
2023	10,518,818	-	10,292,606	1,610,836	1,610,836						
2024	10,292,606	226,211	10,066,395	1,580,405	1,580,405						
2025	10,066,395	226,211	9,840,184	1,549,974	1,549,974	\$ -					
2026	9,840,184	226,211	9,613,973	1,519,543	1,519,543						
2027	9,613,973	226,211	9,387,762	1,489,111	1,489,111						
2028	9,387,762	226,211	9,161,551	1,458,680	1,458,680						
2029	9,161,551	226,211	8,935,340	1,428,249	1,428,249	\$ -					
2030	8,935,340	226,211	8,709,129	1,397,817	1,397,817	\$ -					
2031	8,709,129	226,211	8,482,917	1,367,386	1,367,386						
2032			8,256,706		1,336,955						
	8,482,917	226,211		1,336,955							
2033	8,256,706	226,211	8,030,495	1,306,523	1,306,523						
2034	8,030,495	226,211	7,804,284	1,276,092	1,276,092	\$ -					
2035	7,804,284	226,211	7,578,073	1,245,661	1,245,661						
2036	7,578,073	226,211	7,351,862	1,215,229	1,215,229						
2037	7,351,862	226,211									
2038	7,125,651	226,211	6,899,440	1,154,367	1,154,367	\$ -					
2039	6,899,440	226,211	6,673,228	1,123,935	1,123,935	\$ -					
2040	6,673,228	226,211	6,447,017	1,093,504	1,093,504						
2041	6,447,017	226,211	6,220,806	1,063,073	1,063,073						
2042	6,220,806	226,211	5,994,595	1,032,641	1,032,641						
2043	5,994,595	226,211	5,768,384	1,002,210	1,002,210	\$ -					
2044	5,768,384	226,211	5,542,173	971,779	971,779	\$ -					
2045	5,542,173		5,315,962	941,347	941,347						
2046	5,315,962	226,211	5,089,750	910,916	910,916						
2047	5,089,750	226,211	4,863,539	880,485	880,485						
2048	4,863,539	226,211	4,637,328	850,053	850,053	\$ -					
2049	4,637,328	226,211	4,411,117	819,622	819,622						
2050	4,411,117	226,211	4,184,906	789,191	789,191						
2051	4,184,906	226,211	3,958,695	758,759	758,759						
2052	3,958,695		3,732,484	728,328	728,328						
2053	3,732,484	226,211	3,506,273	697,897	697,897	\$ -					
2054	3,506,273		3,280,061	667,465	667,465						
2055	3,280,061	226,211	3,053,850	637,034	637,034						
2056	3,053,850	226,211	2,827,639	606,603	606,603						
2057	2,827,639	226,211	2,601,428	576,171	576,171	\$ -					
2058	2,601,428	226,211	2,375,217	545,740	545,740						
2059	2,375,217		2,149,006	515,309	515,309						
2060	2,149,006	226,211	1,922,795	484,877	484,877						
2061	1,922,795	226,211	1,696,583	454,446	454,446						
2062	1,696,583	226,211	1,470,372	424,015	424,015						
2063	1,470,372	226,211	1,244,161	393,583	393,583						
2064	1,244,161	226,211	1,017,950	363,152	363,152						
2065	1,017,950		791,739	332,721	332,721						
2066	791,739	226,211	565,528	302,289	302,289	\$ -					
2067	565,528	226,211	339,317	271,858	271,858						
Project Totals	555,520	13,459,562	220,017	70,061,829	70,061,829	•					
i ioject iotais		13,438,362		70,001,629	70,001,629	-					

** 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.

APCo 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

Details

Facilities receiving incentives accepted by FERC in Docket No.

(e.g. ER05-925-000)

Current Projected Year ARR

Current Projected Year ARR w/ Incentive
41,778

Project Description: RTEP ID: b1712.2 (Altavista-Leesville 138kV line)

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

CUMULATIVE HISTORY OF PROJECTED ANNUAL REVENUE REQUIREMENTS:

Investment	267,989	Current Year				201	3	CUMUL	ATIVE HISTORY OF P	ROJECTED ANNUAL	REVENUE REQUIREM	IENTS:
Service Year (yyyy)		ROE increase accepte		nts)			-			ANNUAL REVENUE R		
Service Month (1-12)	12	FCR w/o incentives, le	ss depreciation				13.45%			ITHOUT INCENTIVES		
Useful life	61	FCR w/incentives appr	oved for these facilities	s, less dep.			13.45%			ISTORY OF PROJECT	TED ARRS OVER THE	
CIAC (Yes or No)	No	Annual Depreciation E	xpense				4,393	LIFE OF THE P	ROJECT.			
								DTED Drainated		DTED Drainated		
								RTEP Projected Rev. Req't.From		RTEP Projected Rev. Req't.From		
Investment	Beginning	Depreciation	Ending	RTEP Rev. Req't.	RTEP Rev. Req't.	Incentive	Rev	Prior Year Template		Prior Year Template		
Year	Balance	Expense	Balance	w/o Incentives	with Incentives **	Requirem		w/o Incentives		with Incentives **		
2011	267,989	-	267,989	36,052	36,052	_	-	\$ -				
2012	267,989	226,211	41,778	231,831	231,831	\$	_	\$ -				
2013	41,778		-	41,778		\$	-	\$ -				
2014	, -	-	-	-	-	\$	-					
2015	-	-	-	-	-	\$	-					
2016	-	-	-	-	-	\$	-					
2017	-	-	-	-	-	\$	-					
2018	-	-	-	-	-	\$	-					
2019	-	-	-	-	-	\$	-					
2020	-	-	-	-	-	\$	-					
2021	-	·	-	-	-	Ф Ф	-					
2022 2023	_	·	-	-		φ ¢						
2023	<u> </u>	<u> </u>			<u> </u>	\$						
2025	_	_	_	<u>-</u>	_	\$	_					
2026	-		-	_		\$	-					
2027	-	-	-	-	-	\$	-					
2028	-	-	-	-	-	\$	-					
2029	-	-	-	-	-	\$	-					
2030	-	-	-	-	-	\$	-					
2031	-	-	-	-	-	\$	-					
2032	-	-	-	-	-	\$	-					
2033	-	-	-	-	-	\$	-					
2034 2035		-	-	-	-	\$	-					
2036			_	_		Φ ¢						
2037	_	_	_	_	_	\$	_					
2038	-	-	-	-	-	\$	-					
2039	-	-	-	-	-	\$	-					
2040	-	-	-	-	-	\$	-					
2041	-	-	-	-	-	\$	-					
2042	-	-	-	-	-	\$	-					
2043	-	-	-	-	-	\$	-					
2044 2045	_	-	-	-	-	Ф Ф	-					
2046			_	_		\$						
2047	_	_	_	_	_	\$	_					
2048	-	-	-	-	-	\$	-					
2049	-	-	-	-	-	\$	-					
2050	-	-	-	-	-	\$	-					
2051	-	-	-	-	-	\$	-					
2052	-	-	-	-	-	\$	-					
2053	-	-	-	-	-	\$	-					
2054	-	-	-	-	-	\$ ¢	-					
2055 2056	_	-	<u> </u>	<u>-</u>		φ \$	-					
2057	_		_			\$						
2058	_	_	_	_	_	\$	-					
2059	-	-	-	-	-	\$	-					
2060	-	-	-	-	-	\$	-					
2061	-	-	-	-	-	\$	-					
2062	-	-	-	-	-	\$	-					
2063	-	-	-	-	-	\$	-					
2064	-	-	-	-	-	\$	-					
2065	-	-	-	-	-	\$	-					
2066	-	-	-	-	-	\$ ¢	-					
2067	-	-	-	-	-	Φ Φ	-					
2068	-	-	-	-	-	Ф Ф	-					

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

2070

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 2012 FF1 Balances
Worksheet K Supporting Calculation of TRUE-UP PJM RTEP Project Revenue Requirement Billed to Benefiting Zones
APPALACHIAN POWER COMPANY

Formula Rate APCo WS K TRUE-UP RTEP RR Page 29 of 36

Page 1 of 2

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

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

ROE w/o incentives (True-L	Jp TCOS, In 164	4)	11.49%	
Project ROE Incentive Adde	r		0 <==ROE Adder Cannot Exceed 100 Basis Points	
ROE with additional 0 basis	point incentive		11.49% <== ROE Including Incentives Cannot Exceed 12.5% Until July 1, 201	12
Determine R (cost of long to	erm debt, cost o	f preferred stock and equit	uity percentage is from the True-Up TCOS, Ins 162 through164)	
	<u>%</u>	<u>Cost</u>	Weighted cost	
Long Term Debt	55.07%	5.33%	2.934%	
Preferred Stock	0.00%	0.00%	0.000%	
Common Stock	44.93%	11.49%	<u>5.163%</u>	
		R =	8.097%	

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

Rate Base (True-Up TCOS, In 78)	1,119,671,594
R (fom A. above)	8.097%
Return (Rate Base x R)	90,660,890

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

Return (from B. above)	90,660,890
Effective Tax Rate (True-Up TCOS, In 126)	41.31%
Income Tax Calculation (Return x CIT)	37,451,121
ITC Adjustment	(127,206)
Income Taxes	37.323.915

II. Calculate Net Plant Carrying Charge Rate (Fixed Charge Rate or FCR) with hypothetical 0 basis point ROE increase.

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

Annual Revenue Requirement (True-Up TCOS, In 1)	218,162,992
T.E.A. & Lease Payments (True-Up TCOS, Lns 105 & 106)	-
Return (True-Up TCOS, In 134)	90,660,890
Income Taxes (True-Up TCOS, In 133)	37,323,915
Annual Revenue Requirement, Less TEA	90,178,187
Charges Return and Tayes	

B. Determine Annual Revenue Requirement with hypothetical 0 basis point increase in ROE.

Annual Revenue Requirement, Less TEA Charges, Return and Taxes	90,178,187
Return (from I.B. above)	90,660,890
Income Taxes (from I.C. above)	37,323,915
Annual Revenue Requirement, with 0 Basis Point ROE increase	218,162,992
Depreciation (True-Up TCOS, In 111)	32,077,595
Annual Rev. Req, w/ 0 Basis Point ROE	186,085,397
increase, less Depreciation	

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

Net Transmission Plant (True-Up TCOS, In 48) Annual Revenue Requirement, with 0 Basis Point ROE increase FCR with 0 Basis Point increase in ROE	1,341,956,486 218,162,992 16.26%
Annual Rev. Req, w / 0 Basis Point ROE increase, less Dep.	186,085,397
FCR with 0 Basis Point ROE increase, less Depreciation	13.87%
FCR less Depreciation (True-Up TCOS, In 9)	13.87%
Incremental FCR with 0 Basis Point ROE increase, less Depreciation	0.00%

III. Calculation of Composite Depreciation Rate

Transmission Plant @ Beginning of Historic Period () (P.206, In 58,(b)):	1,942,021,775
Transmission Plant @ End of Historic Period () (P.207, In 58,(g)):	2,040,266,144_
Subtotal	3,982,287,919
Average Transmission Plant Balance for	1,991,143,960
Annual Depreciation Rate (True-Up TCOS, In 111)	32,626,776
Composite Depreciation Rate	1.64%
Depreciable Life for Composite Depreciation Rate	61.03
Round to nearest whole year	61

SUMMARY OF TRUED-UP ANNUAL REVENUE REQUIREMENTS FOR RTEPPROJECTS Rev Require W Incentives Incentive Amounts								
TRUE-UP YEAR	2012							
As Projecte	ed in Prior Year WS J	\$	1,906,118	\$	1,906,118	\$	-	
	Actual after True-up	\$	2,261,880	\$	2,261,880	\$	-	
True-	-up of ARR For 2012		355,762		355,762		-	

Page 2 of 2

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

A. Base Plan Facilities

Facilities receiving incentives accepted by FERC in Docket No.

Project Description: RTEP ID: b0318 (Amos 765/138 kV Transformer)

(e.g. ER05-925-000)

2012 Rev Require W Incentives Incentive Amounts Prior Yr Projected 1,906,118 1,906,118 Prior Yr True-Up 2,014,191 2,014,191 True-Up Adjustment 108,073 108,073

TRUE UP OF PROJECT REVENUE REQUIREMENT FOR PRIOR YEAR:

INPUT TRUE-UP ARR (WITH & WITHOUT INCENTIVES) FROM EACH PRIOR YEAR

CUMULATIVE HISTORY OF TRUED-UP ANNUAL REVENUE REQUIREMENTS:

Details			
Investment	13,798,879	Current Year	2012
Service Year (yyyy)	2008	ROE increase accepted by FERC (Basis Points)	-
Service Month (1-12)	6	FCR w/o incentives, less depreciation	13.87%
Useful life	61	FCR w/incentives approved for these facilities, less dep.	13.87%
CIAC (Voc or No)	No	Appual Depreciation Expanse	226 211

Service Month (1-12)		FCR w/o incentives, le	•	land to			13.87%		`	,	FROM EACH PRIOR Y	EAR
Useful life			roved for these facilities,	less dep.			13.87%	LIFE OF THE F	LOW TO MAINTAIN F	HISTORY OF TRUED-	UP ARRS OVER THE	
CIAC (Yes or No)	INC	Annual Depreciation E	xpense		1	T	226,211		ROJECT.	DTED Projected	1	1
								RTEP Projected	DTED Day Boalt	RTEP Projected	DTED Day Dogle	True up of
Investment	Baginning	Donrociation	Ending	Avaraga	DTED Day Dog!	DTED Day Dogle	Incentive Rev.	Rev. Req't.From Prior Year WS J	RTEP Rev Req't	Rev. Req't.From Prior Year WS J	RTEP Rev Req't	True-up of
Investment Year	Beginning Balance	Depreciation Expense	Ending Balance	Average Balance	RTEP Rev. Req't. w/o Incentives	RTEP Rev. Req't. with Incentives **	Requirement ##	w/o Incentives	True-up w/o Incentives	with Incentives **	True-up with Incentives **	Incentive with Incentives *
2008	13,798,879	•	13,685,773	13,742,326	2,018,716	2,018,716		¢ _	¢ _	¢ _	¢	©
2009	13,685,773		13,459,562	13,572,668	2,108,295	2,108,295		\$ 1,124,469	\$ 983,826	\$ 1,124,469	\$ 983,826	\$ -
2010	13,459,562		13,233,351	13,346,457	2,076,927	2,076,927		\$ 2,027,403				
2011	13,233,351	226,211	13,007,140	13,120,246	2,045,559	2,045,559		\$ 2,050,107				
2012	13,007,140		12,780,929	12,894,034	2,014,191	2,014,191		\$ 1,906,118				
2013	12,780,929	-	12,554,718	12,667,823	1,982,823	1,982,823		Ψ 1,000,110	\$ -	Ψ 1,000,110	\$ -	-
2014	12,554,718		12,328,507	12,441,612	1,951,455	1,951,455			\$ -		-	\$ -
2015	12,328,507		12,102,296	12,215,401	1,920,087	1,920,087			\$ -		\$ -	\$ -
2016	12,102,296		11,876,084	11,989,190	1,888,719	1,888,719			\$ -		\$ -	\$ -
2017	11,876,084		11,649,873	11,762,979	1,857,351	1,857,351			\$ -		\$ -	\$ -
2018	11,649,873	-	11,423,662	11,536,768	1,825,983	1,825,983			\$ -		\$ -	\$ -
2019	11,423,662		11,197,451	11,310,557	1,794,615	1,794,615			\$ -		\$ -	\$ -
2020	11,197,451	226,211	10,971,240	11,084,345	1,763,247	1,763,247	\$ -		\$ -		\$ -	\$ -
2021	10,971,240	226,211	10,745,029	10,858,134	1,731,879	1,731,879	\$ -		\$ -		\$ -	\$ -
2022	10,745,029	226,211	10,518,818	10,631,923	1,700,511	1,700,511	\$ -		\$ -		\$ -	\$ -
2023	10,518,818		10,292,606	10,405,712	1,669,142	1,669,142			\$ -		\$ -	\$ -
2024	10,292,606		10,066,395	10,179,501	1,637,774	1,637,774			\$ -		\$ -	\$ -
2025	10,066,395		9,840,184	9,953,290	1,606,406	1,606,406			\$ -		\$ -	\$ -
2026	9,840,184		9,613,973	9,727,079	1,575,038	1,575,038			\$ -		\$ -	\$ -
2027	9,613,973		9,387,762	9,500,868	1,543,670	1,543,670			\$ -		\$ -	\$ -
2028	9,387,762		9,161,551	9,274,656	1,512,302	1,512,302			\$ -		\$ -	\$ -
2029	9,161,551	226,211	8,935,340	9,048,445	1,480,934	1,480,934			-		-	\$ -
2030	8,935,340	-	8,709,129	8,822,234	1,449,566	1,449,566			-		-	\$ -
2031	8,709,129		8,482,917	8,596,023	1,418,198	1,418,198			-		-	-
2032	8,482,917		8,256,706	8,369,812	1,386,830	1,386,830			-		-	-
2033	8,256,706		8,030,495	8,143,601	1,355,462	1,355,462			-		-	-
2034	8,030,495		7,804,284	7,917,390	1,324,094	1,324,094			-		-	-
2035	7,804,284		7,578,073	7,691,178	1,292,726	1,292,726			-		-	-
2036	7,578,073		7,351,862	7,464,967		1,261,358			-			
2037	7,351,862		7,125,651	7,238,756	1,229,989	1,229,989			- -		-	ф -
2038 2039	7,125,651 6,899,440	226,211 226,211	6,899,440 6,673,228	7,012,545 6,786,334	1,198,621 1,167,253	1,198,621 1,167,253			- С		φ -	ф <u>-</u>
2040	6,673,228		6,447,017	6,560,123	1,135,885	1,135,885			- •		φ - ¢ -	φ - ¢ -
2040	6,447,017		6,220,806	6,333,912	1,104,517	1,104,517			- - -		1	\$ -
2042	6,220,806		5,994,595	6,107,701	1,073,149	1,073,149			φ •		\$	\$ -
2043	5,994,595		5,768,384	5,881,489	1,041,781	1,041,781			\$ -		S -	\$ -
2044	5,768,384		5,542,173	5,655,278	1,010,413	1,010,413			- ·		\$ -	\$ -
2045	5,542,173		5,315,962	5,429,067	979,045	979,045			\$ -		-	-
2046	5,315,962		5,089,750	5,202,856	947,677	947,677			\$ -		-	\$ -
2047	5,089,750		4,863,539	4,976,645	916,309	916,309			\$ -		-	\$ -
2048	4,863,539		4,637,328	4,750,434	884,941	884,941			\$ -		\$ -	\$ -
2049	4,637,328		4,411,117	4,524,223	853,573	853,573			\$ -		\$ -	\$ -
2050	4,411,117		4,184,906	4,298,011	822,205	822,205			\$ -		\$ -	\$ -
2051	4,184,906		3,958,695	4,071,800	790,836	790,836			\$ -		\$ -	\$ -
2052	3,958,695	226,211	3,732,484	3,845,589	759,468	759,468	\$ -		\$ -		\$ -	\$ -
2053	3,732,484	226,211	3,506,273	3,619,378	728,100	728,100	\$ -		\$ -		\$ -	\$ -
2054	3,506,273		3,280,061	3,393,167	696,732	696,732			\$ -		\$ -	\$ -
2055	3,280,061		3,053,850	3,166,956	665,364	665,364			\$ -		\$ -	\$ -
2056	3,053,850		2,827,639	2,940,745	633,996	633,996			\$ -		\$ -	\$ -
2057	2,827,639		2,601,428	2,714,534	602,628	602,628			-		-	\$ -
2058	2,601,428		2,375,217	2,488,322	571,260	571,260			-		-	\$ -
2059	2,375,217		2,149,006	2,262,111	539,892	539,892			-		-	\$ -
2060	2,149,006		1,922,795	2,035,900	508,524	508,524			-		-	\$ -
2061	1,922,795		1,696,583	1,809,689	477,156	477,156			-		-	-
2062	1,696,583		1,470,372	1,583,478	445,788	445,788			-			-
2063	1,470,372		1,244,161	1,357,267	414,420	414,420			-			\$ -
2064	1,244,161		1,017,950	1,131,056	383,051	383,051			-		- -	\$ -
2065	1,017,950		791,739	904,845	351,683	351,683			ф -		- -	5
2066 2067	791,739		565,528	678,633	320,315 288,947	320,315 288,947			ф •		ф Ф	Φ -
Project Totals	565,528	12 450 562	339,317	452,422	288,94 <i>1</i>	288,947 72 727 277	Ψ -		Ψ -		Ψ -	φ -

72,737,377

72,737,377

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

Project Totals

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

13,459,562

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

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)

Prior Yr Projected
Prior Yr True-Up
Prior Yr True-Up
Prior Yr True-Up Adjustment
Prior Yr Docket No.

(e.g. ER05-925-000)

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

Details									
Investment	267,989	Current Year	t Year						
Service Year (yyyy)	2011	ROE increase accepte	ncrease accepted by FERC (Basis Points)						
Service Month (1-12)	12	FCR w/o incentives, les	w/o incentives, less depreciation						
Useful life	61	FCR w/incentives appr	w/incentives approved for these facilities, less dep.						
CIAC (Yes or No)	No	Annual Depreciation E	I Depreciation Expense						

CIAC (Yes or No)	No .	Annual Depreciation Ex	pense				4,393	LIFE OF THE P	ROJECT.			
								RTEP Projected		RTEP Projected		
								Rev. Req't.From	RTEP Rev Req't	Rev. Req't.From	RTEP Rev Req't	True-up of
Investment	Beginning	Depreciation	Ending	Average	RTEP Rev. Req't.	RTEP Rev. Req't.	Incentive Rev.	Prior Year WS J	True-up	Prior Year WS J	True-up	Incentive
Year	Balance	Expense	Balance	Balance	w/o Incentives	with Incentives **	Requirement ##	w/o Incentives	w/o Incentives	with Incentives **	with Incentives **	
2011	267,989	-	267,989	267,989	37,161	37,161		•	\$ -	\$ -	¢ _	¢ _
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2012	267,989	226,211	41,778	154,883	247,688	247,688	5 -	-	5 -	-	ф -	-
2013	41,778	41,778	-	20,889	44,674	44,674	\$ -	-	5 -	5 -	\$ -	5 -
2014	-	-	-	-	-	-	\$ -	-	\$ -	-	\$ -	-
2015	-	-	-	-	-	-	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
2016	-	-	-	-	-	-	\$ -		\$ -		\$ -	\$ -
2017	-	-	-	-	-	-	\$ -		\$ -		\$ -	\$ -
2018	-	-	-	-	-	-	\$ -		\$ -		\$ -	\$ -
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		267 090			330 E34	320 E24	_		т		T	т
Project Totals		267,989			329,524	329,524	-					

^{**} 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 2012 FF1 Balances Worksheet L Supporting Projected Cost of Debt APPALACHIAN POWER COMPANY

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

Lina	(A)	(B)	(C)	(D)	(E)
<u>Line</u> Number	<u>Issuance</u>	Principle Outstanding	Interest Rate	Annual Expense (See Note S on Projected Template)	<u>Notes</u>
1	Long Term Debt (FF1.p. 256-257.h)			Trojected Template)	
2	Advances From Associated Co.	-	4.708%	-	
3					
4	Installment Purchase Contracts (FF1.p. 256-257.	h a)			
5	WV EDA Amos Project, Series 2009A	54,375,000	0.150%	81,563	
6	WV EDA Amos Project, Series 2009B	50,000,000	0.500%	250,000	
7	IPC Mason Series L	100,000,000	2.000%	2,000,000	
8	WV EDA IPC Mountaineer Project, Series 2008A	75,000,000	0.120%	90,000	
9	WV EDA IPC Mountaineer Project, Series 2008B	50,275,000	0.160%	80,440	
10	IPC Putnam County, WV, Series 2008C	30,000,000	4.850%	1,455,000	
11	IPC Putnam County, WV, Series 2008D	40,000,000	4.850%	1,940,000	
12	Russell County, Va Series K	17,500,000	4.625%	809,375	
13	Amos Project, Series 2010A	50,000,000	5.375%	2,687,500	
14	Amos Project, Series 2011A	65,350,000	2.250%	1,470,375	
15	Senior Unsecured Notes - Series S	300,000,000	3.400%	10,200,000	
16	Senior Unsecured Notes - Series T	350,000,000	4.600%	16,100,000	
17 18	Senior Unsecured Notes - Series I Senior Unsecured Notes - Series K	200,000,000 250,000,000	4.950% 5.000%	9,900,000 12,500,000	
19	Senior Unsecured Notes - Series L	250,000,000	5.800%	14,500,000	
20	Senior Unsecured Notes - Series H	200,000,000	5.950%	11,900,000	
21	Senior Unsecured Notes - Series N	250,000,000	6.375%	15,937,500	
22	Senior Unsecured Notes - Series P	250,000,000	6.700%	16,750,000	
23	Senior Unsecured Notes - Series Q	500,000,000	7.000%	35,000,000	
24	Senior Unsecured Notes - Series R	350,000,000	7.950%	27,825,000	
25 26	Floating Rate Senior Unsecured Notes - Series D Sale/Leaseback	275,000,000 2,383,415	0.685% 13.641%	1,883,750 325,126	
20	Sale/Leaseback	2,363,413	13.041%	323,120	
27	Issuance Discount, Premium, & Expenses:				
28	Auction Fees	FF1.p. 256 & 257.Lines Described as Fe	ees	-	
29	Allowable Hedge Amortization (See Ln 45 Below)			1,619,222	
30	Amort of Debt Discount and Expenses	FF1.p. 117.63.c		3,859,577	
31	Amort of Debt Premimums (Enter Negative)	FF1.p. 117.65.c		-	
32	Reacquired Debt:				
33	Amortization of Loss	FF1.p. 117.64.c		1,342,096	
34	Amortization of Gain	FF1.p. 117.66.c		-	
35	Total Interest on Long Term Debt	3,709,883,415	5.14%	190,506,524	
36	Preferred Stock (FF1.p. 250-251)	Preferred Shares Outstanding			
37	4.5% Series - \$100 - 177,465 Shares O/S	r totorioù difered datotarianig	4.50%	_	
38	, ,			-	
39				-	
40	Philippide on Park 1997		2 222		
40	Dividends on Preferred Stock		0.00%	-	
41	Eligible Hedging Gains and Losses (WS M, Ln 34, (E))		1,619,222	
42	Total Projected Capital Structure Balance for 2013 (• • •		6,790,690,020	
43	Financial Hedge Recovery Limit - Five Basis Points			0.0005	
44	Limit of Recoverable Amount	•		3,395,345	
45	Recoverable Hedge Amortization (Lesser of Ln 4	11 or Ln 44)		1,619,222	

AEP East Companies Transmission Cost of Service Formula Rate APPALACHIAN POWER COMPANY

Worksheet M Supporting Calculation of Capital Structure and Weighted Average Cost of Capital Based on Average of Balances At 12/31/2011 & 12/31/2012

(A)	(B)	(C)	(D)	(E)
		Balances @	Balances @	
<u>Line</u>		12/31/2012	12/31/2011	Average
Deve	elopment of Average Balance of Common Equity	· · · · · · · · · · · · · · · · · · ·		
	D	0.050.500.057	0.000 444 454	0.004.400.000
	Proprietary Capital (112.16.c&d)	3,052,563,357	2,936,414,454	2,994,488,906
	Less Preferred Stock (Ln 54 Below)	0	0	4 022 577
	Less Account 216.1 (112.12.c&d)	1,654,344	1,610,810	1,632,577
	Less Account 219.1 (112.15.c&d)	(29,897,592)	(58,543,154)	(44,220,373)
a a	Average Balance of Common Equity	3,080,806,605	2,993,346,798	3,037,076,702
Deve	elopment of Cost of Long Term Debt Based on A	verage Outstanding Ba	alance	
		Torugo Guiotaniunig Di		
6	Bonds (112.18.c&d)	-	-	-
	Less: Reacquired Bonds (112.19.c&d)	-	-	-
8	LT Advances from Assoc. Companies (112.20.c&d)	-	-	-
9	Senior Unsecured Notes (112.21.c&d)	3,709,883,415	3,734,408,392	3,722,145,904
10	Less: Fair Value Hedges (See Note on Ln 12 below)	-	-	-
11	Total Average Debt	3,709,883,415	3,734,408,392	3,722,145,904
10	NOTE: The belonce of fair value hadron on cutatonding la	una taum daht ara ta ha awa	luded from the bele	waa af lawa tawa dabt
12	NOTE: The balance of fair value hedges on outstanding lo included in the formula's capital structure. (Column H of the	_	luded from the bala	ince of long term debt
	included in the formula's capital structure. (Column 11 of the	ie 11 1 <i>)</i>		
13	Annual Interest Expense for 2012			
	Interest on Long Term Debt (256-257.33.i)			193,138,993
	Less: Total Hedge Gain/Expense Accumulated from p 256-25	7. col. (i) of FERC Form 1		, ,
15	included in Ln 14 and shown in Ln 33 below.	, , , , , , , , , , , , , , , , , , , ,		1,619,222
16	Plus: Allowed Hedge Recovery From Ln 38 below.			1,619,222
	Amort of Debt Discount & Expense (117.63.c)			3,859,577
	Amort of Loss on Reacquired Debt (117.64.c)			1,342,096
	Less: Amort of Premium on Debt (117.65.c)			-
	Less: Amort of Gain on Reacquired Debt (117.66.c)			_

CALCULATION OF RECOVERABLE HEDGE GAINS/LOSSES

21 Total Interest Expense (Ln 14 + Ln 17 + Ln 18 - Ln 19 - Ln 20)

22 Average Cost of Debt for 2012 (Ln 21/Ln 11)

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

HEDGE AMOUNTS BY ISSUANCE (FROM p. 256-25 the FERC Form 1)	7 (i) of Total Hedge (Gain)/Loss for 2012	Less Excludable Amounts (See NOTE on Line 23)	Net Includable Hedge Amount	Remaining Unamortized Balance	Beginning	Ending
24 Senior Unsecured Notes - Series I	764,169		764,169	1,209,935	Jan-05	Feb-15
25 Senior Unsecured Notes - Series K	1,336,324		1,336,324	3,229,451	Jun-05	Jun-17
26 Senior Unsecured Notes - Series O	60,287		60,287	(0)	Aug-07	Aug-12
27 Senior Unsecured Notes - Series L	(238,880)		(238,880)	(656,918)	Sep-05	Oct-35
28 Senior Unsecured Notes - Series H	37,068		37,068	753,816	May-03	May-33
29 Senior Unsecured Notes - Series N	(194,198)		(194,198)	(4,515,114)	Apr-06	Apr-36
30 Senior Unsecured Notes - Series Q	159,672		159,672	4,025,043	Mar-08	Apr-38
31 Senior Unsecured Notes - Series S	826,212	-	826,212	1,981,131	May-10	May-15
32 Senior Unsecured Notes - Series T	(1,131,432)	-	(1,131,432)	(9,302,888)	Mar-11	Mar-21
	,		- 1			
33 Total Hedge Amortization	1,619,222	-				
34 Hedge Gain or Loss Prior to Application of Recovery L 35 Total Average Capital Structure Balance for 2012 (True 36 Financial Hedge Recovery Limit - Five Basis Points of	e-UP TCOS, Ln 165)		1,619,222 6,759,222,605 0.0005			

198,340,666

3,379,611

1,619,222

5.33%

Amortization Period

Development of Cost of Preferred Stock

38 Recoverable Hedge Amortization (Lesser of Ln 34 or Ln 37)

37 Limit of Recoverable Amount

Drafarra d Ctante			A	
Preferred Stock 39 4.5% Series - 100 - Dividend Rate (p. 250-251. 7 & 10.a) 40 4.5% Series - 100 - Par Value (p. 250-251. 8.c) 41 4.5% Series - 100 - Shares O/S (p.250-251. 8 & 11.e)	\$ 4.50% 100.00 \$ -	4.50% 100.00	<u>Average</u>	
42 4.5% Series - 100 - Monetary Value (Ln 40 * Ln 41) 43 4.5% Series - 100 - Dividend Amount (Ln 39 * Ln 42)	- -	- -	-	
44 0% Series Dividend Rate (p. 250-251.a) 45 0% Series Par Value (p. 250-251.c) 46 0% Series Shares O/S (p.250-251. e)				
47 4.5% Series - 100 - Monetary Value (Ln 45 * Ln 46) 48 0% Series Dividend Amount (Ln 44 * Ln 47)	- -	-	-	
49 0% Series Dividend Rate (p. 250-251.a) 50 0% Series Par Value (p. 250-251.c) 51 0% Series Shares O/S (p.250-251.e)				
52 4.5% Series - 100 - Monetary Value (Ln * Ln 49) 53 0% Series Dividend Amount (Ln 49 * Ln 52)	- -	-	-	
54 Balance of Preferred Stock (Lns 42, 47, 52) 55 Dividends on Preferred Stock (Lns 43, 48, 53) 56 Average Cost of Preferred Stock (Ln 55/54)	- - 0.00%	0.00%	- - 0.00%	Year End Total Agrees to FF1 p.112, Ln 3, col (c) & (d)

AEP East Companies Cost of Service Formula Rate Using 2012 FF1 Balances Worksheet N - Gains (Losses) on Sales of Plant Held For Future Use APPALACHIAN POWER COMPANY

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

	(A)	(B)	(C) (D) Function	(E)	(F)	(G) Functional	(H) Functionalized	(I) FERC
Line	Date	Property Description	(T) or (G) Basis T = Transmission G = General	Proceeds	(Gain) / Loss	Allocator	Proceeds (Gain) / Loss	Account
1					-	0.000%	-	
2					-	0.000%	-	
3					-	0.000%	-	
4			Net (Gain) or	Loss for 2012			-	

AEP East Companies Cost of Service Formula Rate Using 2012 FF1 Balances Worksheet O - Calculation of Postemployment Benefits Other than Pensions Expenses Allocable to Transmission Service APPALACHIAN POWER COMPANY

Total AEP East Operating Company PBOP Settlement Amount

48,100,000

Allocation of PBOP Settlement Amount for 2012:

			otal company / uncum	•				
Line#	Company	Actual Expense (Including AEPSC Billed OPEB)	Ratio of Company Actual to Total	Allocation of PBOB Recovery Allowance	Labor Allocator for 2012	Actual Expense	Allowable Expense	One Year Functional Expense (Over)/Under
		(A) (Line 14)	(B)=(A)/Total (A)	(C)=(B) * 48100000	(D)	(E)=(A) * (D)	(F)=(C) * (D)	(G)=(E) - (F)
1 APC	Co	11,359,793	27.78%	13,362,440	7.081%	804,397	946,207	(141,809)
2								
3 I&M		10,586,657	25.89%	12,453,006	4.206%	445,250	523,744	(78,494)
4 KPC	Co	2,188,039	5.35%	2,573,774	9.694%	212,116	249,511	(37,394)
5 KNG	SP .	277,875	0.68%	326,862	13.137%	36,506	42,941	(6,436)
6 OPC	Co	16,164,303	39.53%	19,013,950	6.771%	1,094,477	1,287,425	(192,948)
7 WPG	Co	314,520	0.77%	369,968	7.846%	24,676	29,026	(4,350)
8	Sum of Lines 1 to 7	40,891,187	•	48,100,000		2,617,422	3,078,853	(461,432)

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

	APCo	<u>I&M</u>	<u>KPCo</u>	KNGSPT	<u>OPCo</u>	<u>WPCo</u>	AEP East Total
9 Direct Charged PBOP Expense per Actuarial Report *	10,991,074	9,836,923	1,994,927	247,734	13,628,228	282,183	36,981,069
10 Additional PBOP Ledger Entries (from Company Records)	(669,581)	(45,394)	-	-	1,105,077	-	
11 Medicare Subsidy *	-	-	-	-	-	-	-
12 Net Company Expense (Ln 9 + Ln 10 + Ln 11)	10,321,493	9,791,529	1,994,927	247,734	14,733,305	282,183	37,371,171
13 PBOP Expenses From AEP Service Corporation (from Company Records)	1,038,300	795,128	193,112	30,141	1,430,998	32,337	3,520,016
14 Company PBOP Expense (Ln 12 + Ln 13)	11,359,793	10,586,657	2,188,039	277,875	16,164,303	314,520	40,891,187

^{*} Sourced from Actuarial Report

AEP EAST COMPANIES

Worksheet - P CALCULATION OF

TOTAL WEIGHTED AVERAGE DEPRECIATION RATES FOR TRANSMISSION PLANT PROPERTY ACCOUNT

EFFECTIVE AS OF 2/1/2012

FOR MULTIPLE JURISDICTION COMPANIES

APPALACHIAN POWER COMPANY

	VIRGINIA			WEST VIRGINIA		FERC WHOLESALE			FERC KINGSPORT			COMPANY		
	_	(1)		WTD AVG.	(2) PSC OF WV		WTD AVG.	(3)		WTD AVG.	(4)		WTD AVG.	WTD AVG.
	PLANT ACCT.	VA SCC RATES	ALLOCATION FACTOR (5)	DEPREC. RATE	APPROVED RATES	ALLOCATION FACTOR (5)	DEPREC. RATE	FERC RATES	ALLOCATION FACTOR (5)	DEPREC. RATE	FERC RATES	ALLOCATION FACTOR (5)	DEPREC. RATE	DEPREC. RATE
TRANSMISSION PLANT														
Land Rights - Va.	350.1	0.66%	1.000000	0.66%										0.66%
Structures & Improvements	352.0	1.55%	0.455791	0.71%	1.55%	0.444609	0.69%	2.19%	0.039062	0.09%	2.19%	0.060538	0.13%	1.62%
Station Equipment	353.0	1.95%	0.455791	0.89%	1.95%	0.444609	0.87%	2.19%	0.039062	0.09%	2.19%	0.060538	0.13%	1.98%
Towers & Fixtures	354.0	1.14%	0.455791	0.52%	1.14%	0.444609	0.51%	2.19%	0.039062	0.09%	2.19%	0.060538	0.13%	1.25%
Poles & Fixtures	355.0	2.77%	0.455791	1.26%	2.77%	0.444609	1.23%	2.19%	0.039062	0.09%	2.19%	0.060538	0.13%	2.71%
Overhead Conductor	356.0	1.01%	0.455791	0.46%	1.01%	0.444609	0.45%	2.19%	0.039062	0.09%	2.19%	0.060538	0.13%	1.13%
Underground Conduit	357.0	1.23%	0.455791	0.56%	1.24%	0.444609	0.55%	2.19%	0.039062	0.09%	2.19%	0.060538	0.13%	1.33%
Underground Conductors	358.0	3.18%	0.455791	1.45%	3.18%	0.444609	1.41%	2.19%	0.039062	0.09%	2.19%	0.060538	0.13%	3.08%

- (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.

INDIANA MICHIGAN POWER COMPANY

Line No.						Tr	ansmission Amount
1	REVENUE REQUIREMENT (w/o incentives)	(In 138)	+	• 11		(\$125,959,874
2	REVENUE CREDITS	(Note A) (Worksheet E)	Total 947,294	DA	1.00000	\$	947,294
3	REVENUE REQUIREMENT For All Company Facilities	(In 1 less In 2)				\$	125,012,580
	The Carrying Charge Calculations on lines 6 to 11 belons in the second second second control of the second con						
4	Revenue Requirement for PJM Schedule 12 Facilities (v	w/o incentives) (Worksheet J)	2,666,168	DA	1.00000	\$	2,666,168
5 6 7	NET PLANT CARRYING CHARGE w/o intra-AEP charge Annual Rate Monthly Rate	es or credits or ROE incentives (Note B) ((In 1 - In 105 - In 106)/((In 48 + In 49 + In 50 (In 6 / 12)	+ In 51 + In 53) x 100))				17.38% 1.45%
8 9	NET PLANT CARRYING CHARGE ON LINE 6, w/o dep Annual Rate	reciation or ROE incentives (Note B) ((In 1 - In 105 - In 106 - In 111 - In 112) /((In 4	8 + ln 49 + ln 50 + ln 51 + ln 5	3) x 100))			14.80%
10 11	NET PLANT CARRYING CHARGE ON LINE 9, w/o Retu Annual Rate	rn, income taxes or ROE incentives (Note B) ((In 1 - In 105 - In 106 - In 111 - In 112 - In 13	3 - In 134) /((In 48 + In 49 + In	50 + ln 51 + ln 53)	x 100))		4.58%
12	ADDITIONAL REVENUE REQUIREMENT for projects w	/ incentive ROE's (Note B) (Worksheet J)					-
13		REVENUE REQUIREMENT FOR SCHED	ULE 1A CHARGES				
14 15 16	Total Load Dispatch & Scheduling (Account 561) Less: Load Dispatch - Scheduling, System Control and Less: Load Dispatch - Reliability, Planning & Standards	. , ,					8,132,792 5,531,795 1,083,397
17	Total 561 Internally Developed Costs	(Line 14 - Line 15 - Line 16)					1,517,600

INDIANA MICHIGAN POWER COMPANY

	(1)	(2)	(3)	(4)	(5)
	RATE BASE CALCULATION	Data Sources (See "General Notes")	TO Total	Allo	<u>cator</u>	Total <u>Transmission</u>
Line No.	GROSS PLANT IN SERVICE		NOTE C			
18	Production	(Worksheet A In 1.C)	4,037,746,725	NA	0.00000	_
19	Less: Production ARO (Enter Negative)	(Worksheet A In 2.C)	(303,665,963)	NA	0.00000	-
20	Transmission	(Worksheet A In 3.C & Ln 142)	1,278,027,455	DA	0.00000	1,207,351,314
21	Less: Transmission ARO (Enter Negative)	(Worksheet A In 4.C& Ln 143)	-	TP	0.94470	-
22	Plus: Transmission Plant-in-Service Additions (Wo	,	56,854,607	DA	1.00000	56,854,607
23	Plus: Additional Trans Plant on Transferred Assets		-	DA	1.00000	-
24	Distribution	(Worksheet A In 5.C)	1,553,155,453	NA	0.00000	-
25	Less: Distribution ARO (Enter Negative)	(Worksheet A In 6.C)	-	NA	0.00000	-
26	General Plant	(Worksheet A In 7.C)	107,811,687	W/S	0.04206	4,534,307
27	Less: General Plant ARO (Enter Negative)	(Worksheet A In 8.C)	(172,922)	W/S	0.04206	(7,273)
28	Intangible Plant	(Worksheet A In 9.C)	139,775,289	W/S	0.04206	5,878,622
29	TOTAL GROSS PLANT (sum Ins 18 to 28)		6,869,532,331			1,274,611,577
30	ACCUMULATED DEPRECIATION AND AMORTIZATI	ON				
31	Production	(Worksheet A In 12.C)	2,318,062,105	NA	0.00000	-
32	Less: Production ARO (Enter Negative)	(Worksheet A In 13.C)	(84,627,053)	NA	0.00000	-
33	Transmission	(Worksheet A In 14.C & 28.C)	537,188,312	TP1=	0.96948	520,792,956
34	Less: Transmission ARO (Enter Negative)	(Worksheet A In 15.C)	-	TP1=	0.96948	-
35	Plus: Transmission Plant-in-Service Additions (Wo	•	544,141	DA	1.00000	544,141
36	Plus: Additional Projected Deprec on Transferred A	,	-	DA	1.00000	<u>-</u>
37	Plus: Additional Transmission Depreciation for 201		18,714,918	TP1	0.96948	18,143,726
38	Plus: Additional General & Intangible Depreciation	·	18,589,864	W/S	0.04206	781,846
39	Plus: Additional Accum Deprec on Transferred Ass		470 225 470	DA	1.00000	-
40 41		(Worksheet A In 16.C) (Worksheet A In 17.C)	479,335,470	NA NA	0.00000 0.00000	-
42	Less: Distribution ARO (Enter Negative) General Plant	(Worksheet A In 18.C)	27,301,514	W/S	0.00000	- 1,148,238
43	Less: General Plant ARO (Enter Negative)	(Worksheet A In 19.C)	(138,294)	W/S	0.04206	(5,816)
44	Intangible Plant	(Worksheet A In 20.C)	132,615,751	W/S	0.04206	5,577,508
45	TOTAL ACCUMULATED DEPRECIATION	(sum Ins 31 to 44)	3,447,586,728		0.0.200	546,982,599
40	NET DI ANT IN CEDI (ICE					
46 47	NET PLANT IN SERVICE Production	(ln 18 + ln 19 - ln 31 - ln 32)	1,500,645,710			
47 48	Transmission	(ln 20 + ln 21 - ln 33 - ln 34)	740,839,143			- 686,558,358
49	Plus: Transmission Plant-in-Service Additions (In 2	,	56,310,466			56,310,466
50	Plus: Additional Trans Plant on Transferred Assets	,	-			-
51	Plus: Additional Transmission Depreciation for 201	,	(18,714,918)			(18,143,726)
52	Plus: Additional General & Intangible Depreciation	· ·	(18,589,864)			(781,846)
53	Plus: Additional Accum Deprec on Transferred Ass		-			-
54	Distribution	(ln 24 + ln 25 - ln 40 - ln 41)	1,073,819,983			-
55	General Plant	(ln 26 + ln 27 - ln 42 - ln 43)	80,475,545			3,384,613
56	Intangible Plant	(In 28 - In 44)	7,159,538			301,113
57	TOTAL NET PLANT IN SERVICE	(sum Ins 47 to 56)	3,421,945,603			727,628,978
58	DEFERRED TAX ADJUSTMENTS TO RATE BASE	(Note D)				
59	Account No. 281.1 (enter negative)	(Worksheet B, In 2 & In 5.C)	(246,285)	NA		-
60	Account No. 282.1 (enter negative)	(Worksheet B, In 7 & In 10.C)	(920,003,284)	DA		(151,405,593)
61	Account No. 283.1 (enter negative)	(Worksheet B, In 12 & In 15.C)	(664,464,895)	DA		(9,424,522)
62 63	Account No. 190.1 Account No. 255 (enter negative)	(Worksheet B, In 17 & In 20.C) (Worksheet B, In 24 & In 25.C)	755,767,692	DA DA		15,048,413
63 64	TOTAL ADJUSTMENTS	(sum Ins 59 to 63)	(828,946,772)	DA		(145,781,702)
04	TOTAL ADJUSTIMENTS	(Sulli ilis 39 to 63)	(020,940,772)			(145,761,702)
65	PLANT HELD FOR FUTURE USE	(Worksheet A In 29.C & In 30.C)	6,294,968	DA		208,360
66	REGULATORY ASSETS	(Worksheet A In 36. (C))	-	DA		-
67	WORKING CAPITAL	(Note E)				
68	Cash Working Capital	(1/8 * In 88)	2,257,790			2,132,932
69	Transmission Materials & Supplies	(Worksheet C, In 2.(D))	1,954,137	TP	0.94470	1,846,071
70	A&G Materials & Supplies	(Worksheet C, In 3.(D))	52,111	W/S	0.04206	2,192
71	Stores Expense	(Worksheet C, In 4.(D))	- -	GP(h)	0.17875	-
72	Prepayments (Account 165) - Labor Allocated	(Worksheet C, In 6.G)	144,686,210	W/S	0.04206	6,085,164
73	Prepayments (Account 165) - Gross Plant	(Worksheet C, In 6.F)	5,571,844	GP(h)	0.17875	995,960
74	Prepayments (Account 165) - Transmission Only	(Worksheet C, In 6.E)	-	DA	1.00000	-
75	Prepayments (Account 165) - Unallocable	(Worksheet C, In 6.D)	(139,407,819)	NA	0.00000	
76	TOTAL WORKING CAPITAL	(sum Ins 68 to 75)	15,114,273		11,062,318	
77	IPP CONTRIBUTIONS FOR CONSTRUCTION	(Note F) (Worksheet D, In 7.B)	(2,810,348)	DA	1.00000	(2,810,348)
78	RATE BASE (sum Ins 57, 64, 65, 66, 76, 77)		2,611,597,724			590,307,606
, 0	= = (0		2,011,001,127			333,337,300

INDIANA MICHIGAN POWER COMPANY

(1) (2) (3) (4) (5)

	EXPENSE, TAXES, RETURN & REVENUE REQUIREMENTS CALCULATION	Data Sources (See "General Notes")	TO Total	Allo	<u>cator</u>	Total <u>Transmission</u>
Line						
No.	OPERATION & MAINTENANCE EXPENSE					
79	Production	321.80.b	1,354,855,751			
80	Distribution	322.156.b	54,052,769			
81	Customer Related Expense	322.164,171,178.b	39,354,797			
82	Regional Marketing Expenses	322.131.b	5,602,674			
83	Transmission	321.112.b	40,026,099			
84	TOTAL O&M EXPENSES	(sum Ins 79 to 83)	1,493,892,090			
85	Less: Total Account 561	(Note G) (Worksheet F, In 12.C)	8,132,792			
86	Less: Account 565	(Note H) 321.96.b	13,667,883			
87	Less: State Regulatory Deferrals & Amortizations	(Note I) (Worksheet F, In 4.C)	163,108			
88	Total O&M Allocable to Transmission	(Ins 83 - 85 - 86 - 87)	18,062,316	TP	0.94470	17,063,453
89	Administrative and General	323.197.b (Note J)	127,509,877			
90	Less: Acct. 924, Property Insurance	323.185.b	4,407,050			
91	Acct. 9260039 PBOP Expense	PBOP Worksheet O Line 9 & 10, (Note K)	9,791,529			
92	Acct. 9260057 PBOP Medicare Subsidy	PBOP Worksheet O Line 11, (Note K)	· · -			
93	PBOP Expense Billed From AEPSC	PBOP Worksheet O Line 13, (Note K)	795,128			
94	Acct. 928, Reg. Com. Exp.	323.189.b	13,085,376			
95	Acct. 930.1, Gen. Advert. Exp.	323.191.b	276,915			
96	Acct. 930.2, Misc. Gen. Exp.	323.192.b	5,318,780			
97	Balance of A & G	(In 89 - sum In 90 to In 96)	93,835,099	W/S	0.04206	3,946,485
98	Plus: Acct. 924, Property Insurance	(In 90)	4,407,050	GP(h)	0.17875	787,754
99	Acct. 928 - Transmission Specific	Worksheet F In 17.(E) (Note L)	-,407,000	TP	0.94470	707,704
100	Acct 930.1 - Only safety related ads -Direct	Worksheet F In 32.(E) (Note L)	_	TP	0.94470	_
101	Acct 930.2 - Misc Gen. Exp Trans	Worksheet F In 40.(E) (Note L)	184,289	DA	1.00000	184,289
102	Settlement Approved PBOP Recovery	PBOP Worksheet O, Col. C, Line 3, (Note M)	12,453,006	W/S	0.04206	523,744
103	A & G Subtotal	(sum Ins 97 to 102)	110,879,444	VV/O	0.04200	5,442,272
103	A & G Subiolai	(Sull ills 97 to 102)				
104	O & M EXPENSE SUBTOTAL	(In 88 + In 103)	128,941,760			22,505,725
105	Plus: TEA Settlement in Account 565	Company Records (Note H)	-	DA	1.00000	-
106	Plus: Transmission Lease Payments To Affiliates in A	cct 565 (Company Records) (Note H)	<u>-</u>	DA	1.00000	
107	TOTAL O & M EXPENSE	(ln 104 + ln 105 + ln 106)	128,941,760			22,505,725
108	DEPRECIATION AND AMORTIZATION EXPENSE					
109	Production	336.2-6.f	67,479,165	NA	0.00000	-
110	Distribution	336.8.f	38,889,909	NA	0.00000	-
111	Transmission	336.7.f	18,714,918	TP1	0.96948	18,143,726
112	Plus: Transmission Plant-in-Service Additions (Works	sheet I In 21.I)	544,141	DA	1.00000	544,141
113	General	336.10.f	3,466,837	W/S	0.04206	145,807
114	Intangible	336.1.f	15,123,027	W/S	0.04206	636,039
115	TOTAL DEPRECIATION AND AMORTIZATION	(Lns 109+110+111	144,217,997			19,469,713
		+112+113+114)				
116	TAXES OTHER THAN INCOME	(Note N)				
117	Labor Related					
118	Payroll	Worksheet H In 22.(D)	12,399,142	W/S	0.04206	521,479
119	Plant Related	()	, = = = ,			,
120	Property	Worksheet H In 22.(C) & In 47.(C)	46,385,973	DA		8,974,114
121	Gross Receipts/Sales & Use	Worksheet H In 22.(F)	12,850,498	NA	0.00000	-
122	Other	Worksheet H In 22.(E)	1,628,831	GP(h)	0.17875	291,151
123	TOTAL OTHER TAXES	(sum Ins 118 to 122)	73,264,444	J. ()		9,786,744
120	TOTAL OTTLER TAKES	(04111110 110 10 122)	70,201,111			0,700,711
124	INCOME TAXES	(Note O)				
125	T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =	(11010-0)	38.80%			
126	EIT=(T/(1-T)) * (1-(WCLTD/WACC)) =		44.13%			
127	where WCLTD=(In 162) and WACC = (In 165)		11.1070			
128	and FIT, SIT & p are as given in Note O.					
129	GRCF=1 / (1 - T) = (from In 125)		1.6341			
130	Amortized Investment Tax Credit (enter negative)	(FF1 p.114, In 19.c)	(4,502,458)			
100	Amortized investment rax orealt (enter negative)	(11 1 p.114, iii 10.0)	(4,302,430)			
131	Income Tax Calculation	(In 126 * In 134)	102,404,032			23,146,704
132	ITC adjustment	(ln 129 * ln 130)	(7,357,258)	NP(h)	0.20284	(1,492,328)
133	TOTAL INCOME TAXES	(sum Ins 131 to 132)	95,046,774	(11)	JU_U T	21,654,375
		,				
134	RETURN ON RATE BASE (Rate Base * WACC)	(In 78 * In 165)	232,062,470			52,453,806
135	INTEREST ON IPP CONTRIBUTION FOR CONST. (Not	e F) (Worksheet D, In 2.(B))	89,510	DA	1.00000	89,510
136	(Gains) / Losses on Sales of Plant Held for Future Use (Worksheet N, In 4, Cols. ((F) & (H))	-			-
137	Tax Impact on (Gains) / Losses on Sales of Plant Held for	or Future Use (In 136 * In126)	-			-
138	TOTAL REVENUE REQUIREMENT	-	673,622,955			125,959,874
100	(cum loc 107 115 122 123 124 125 126 127)	-	37 3,322,333			120,000,017

(sum Ins 107, 115, 123, 133, 134, 135, 136, 137)

INDIANA MICHIGAN POWER COMPANY

SUPPORTING CALCULATIONS

ln								
No.	TRANSMISSION PLANT INCLUDED IN PJM TARIFF							
139	Total transmission plant	(In 20)						1,278,027,455
140	Less transmission plant excluded from PJM Tariff (Note	eP)						-
141	Less transmission plant included in OATT Ancillary Ser	vices (Worksheet A, In 23, Col.	(C)) (Note Q)				_	70,676,141
142	Transmission plant included in PJM Tariff	(In 139 - In 140 - In 141)					_	1,207,351,314
143	Percent of transmission plant in PJM Tariff	(ln 142 / ln 139)					TP	0.94470
				Payroll Billed from				
144	WAGES & SALARY ALLOCATOR (W/S)	(Note R)	Direct Payroll	AEP Service Corp.	Total			
145	Production	354.20.b	129,153,471	10,365,139	139,518,610	NA	0.00000	-
146	Transmission	354.21.b	4,770,177	3,227,159	7,997,336	TP	0.94470	7,555,076
147	Regional Market Expenses	354.22.b	0	0	-	NA	0.00000	-
148	Distribution	354.23.b	19,070,176	2,341,225	21,411,401	NA	0.00000	-
149	Other (Excludes A&G)	354.24,25,26.b	5,951,661	4,757,127	10,708,788	NA	0.00000	
150	Total	(sum Ins 145 to 149)	158,945,485	20,690,650	179,636,135			7,555,076
151	Transmission related amount						W/S=	0.04206
152	WEIGHTED AVERAGE COST OF CAPITAL (WACC)							\$
153	Long Term Interest	(Worksheet L, In. 26, col. (D))					_	91,995,574
154	Preferred Dividends	(Worksheet L, In. 31, col. (D))						-
155	Development of Common Stock:	(
156	Proprietary Capital	(FF1 p 112, Ln 16.c)						1,803,774,755
157	Less: Preferred Stock	(FF1 p 112, Ln 3.c)						-
158	Less: Account 216.1	(FF1 p 112, Ln 12.c)						(104,879)
159	Less: Account 219	(FF1 p 112, Ln 15.c)						(28,884,204)
160	Common Stock	(In 156 - In 157 - In 158 - In 15	i9)				0	1,832,763,838
161				\$	%		Cost (Note S)	Weighted
162	Long Term Debt (Note T) Worksheet L, In 26, col. (B))			1,572,429,608	46.18%		0.0585	0.0270
163	Preferred Stock (In 157)			-	0.00%		-	0.0000
164	Common Stock (In 160)			1,832,763,838	53.82%		11.49%	0.0618
165	,			3,405,193,446			WACC=	0.0889

Transmission Cost of Service Formula Rate
Utilizing Historic Cost Data for 2012 and Projected Net Plant at Year-End 2013

INDIANA MICHIGAN POWER COMPANY

<u>Letter</u> <u>Notes</u>

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

Revenue credits include:

1) Forfeited Discounts.

Α

- 2) Miscellaneous Service Revenues.
- 3) Rental revenues earned on assets included in the rate base.
- 4) Revenues for associated business projects provided by employees whose labor and overhead costs are in the transmission cost of service.
- 5) Other electric revenues.
- 6) Revenues for grandfathered PTP contracts included in the load divisor.

See Worksheet E for details.

- B The annual and monthly net plant carrying charges on page 1 are used to compute the revenue requirement for RTEP sponsored upgrades or those projects receiving approved incentive-ROE's.
- C Transmission Plant balances in this study are projected as of December 31, 2013. Other ratebase amounts are as of December 31, 2012.
- The total-company balances shown for Accounts 281, 282, 283, 190 only reflect ADIT that relates to utility operations. The balance of Account 255 is reduced by prior flow throughs and is completely excluded if the utility chose to utilize amortization of tax credits against FIT expense. An exception to this is pre-1971 ITC balances, which are required to be taken as an offset to rate base. Account 281 is not allocated. In compliance with FERC Rulemaking RM02-7-000, Asset Retirement Obligation deferrals have been removed from ratebase. Transmission ADIT allocations are shown on WS B.

The company will not include the ADIT portion of deferred hedge gains and losses in rate base.

- E Cash Working Capital assigned to transmission is one-eighth of O&M allocated to transmission, as shown on line 88. It excludes:
 - 1) Load Scheduling & Dispatch Charges in account 561 that are collected in the OATT Ancilliary Services Revenue, as shown on line 85.
 - 2) AEP transmission equalization transfers, as shown on line 86
 - 3) The impact of state regulatory deferrals and amortizations, as shown on line 87
 - 4) All A&G Expenses, as shown on line 103.
- Consistent with Paragraph 657 of Order 2003-A, the amount on line 77 is equal to the balance of IPP System Upgrade Credits owed to transmission customers that made contributions toward the construction of System upgrades, and includes accrued interest and unreturned balance of contributions. The annual interest expense is included on line 135.
- Removes from the cost of service the Load Scheduling and Dispatch expenses booked to accounts 561.1 through 561.8. Expenses recorded in these accounts, with the exception of 561.4 & 561.8 (lines 15 & 16 above) are recovered in Schedule 1A, OATT ancillary services rates. See Worksheet F, lines 3 through 12, for descriptions and the Form 1 Source of these accounts' balances.
- Removes cost of transmission service provided by others to determine the basis of cash working capital on line 88. To the extent such service is incurred to provide the PJM service at issue, e.g. transmission equalization agreement, such costs are added back on lines 105 and 106 to determine the total O&M collected in the formula. The amounts on lines 105 and 106 are also excluded in the calculation of the FCR percentage calculated on lines 5 through 11. The addbacks on lines 105 and 106 of activity recorded in 565 represents inter-company sales or purchases of transmission capacity necessary to meet each AEP company's transmission load relative to their available transmission capacity.

The company records referenced on lines 105 and 106 is the INDIANA MICHIGAN POWER COMPANY general ledger.

- I Removes the impact of state regulatory deferrals or their amortization from O&M expense.
- J General Plant and Administrative & General expenses, other than in accounts 924, 928, and 930, will be functionalized based on the Wages & Salaries "W/S" allocator. The allocation basis for accounts 924, 928 and 930 are separately presented in the formula. A change in the allocation method for an account must be approved via a 205 filing with the FERC.
- K These deductions on lines 91 through 93 are to remove from the cost of service the expenses recorded by the company for Postemployment Benefits Other than Pensions (PBOP). See Note M below for the recoverable PBOP expense.
- Expenses reported for these A&G accounts will be included in the cost of service only to the extent they are directly assignable to transmission service. Worksheet F allocates these expense items. Acct 928 Includes Regulatory Commission expenses itemized in FERC Form-1 at page 351, column H. FERC Assessment Fees and Annual Charges shall not be allocated to transmission. Only safety-related and educational advertising costs in Account 930.1 are included in the TCOS. Account 930.2 includes the expenses incurred by the transmission function for Associated Business Development revenues given as a credit to the TCOS on Worksheet E.
- M See note K above. Per the settlement in Docket ER08-1329, recoverable PBOP expense is based on an annual total for the operating companies that is ratioed to them based on the total of actual annual PBOP costs, including charges from the AEP Service Corportation. The calculation of the recoverable amount for each company is shown on Worksheet O, and the process for updating the annual total is documented on Attachment F, Allowable PBOP Expense Formula.
- N Includes only FICA, unemployment, highway, property and other assessments charged in the current year. Gross receipts, sales & use and taxes related to income are excluded.
- O The currently effective income tax rate, where FIT is the Federal income tax rate; SIT is the State income tax rate, and p = the percentage of federal income tax deductible for state income taxes. See Worksheet G for the development of the Company's composite SIT. A utility that elected to utilize amortization of tax credits against taxable income, rather than book tax credits to Account No. 255 and reduce rate base, must reduce its income tax expense by the amount of the Amortized Investment Tax Credit (Form 1, 266.8.f)

 (In 130) multiplied by (1/1-T). If the applicable tax rates are zero enter 0.

Inputs Required:

FIT = 35.00%

SIT= 5.85% (State Income Tax Rate or Composite SIT. Worksheet G))
p = 0.00% (percent of federal income tax deductible for state purposes)

- P Removes plant excluded from the OATT because it does not meet the PJM's definition of Transmission Facilities or is otherwise ineligible to be recovered under the OATT.
- Q Removes transmission plant (e.g. step-up transformers) included in the development of OATT ancillary service rates and not already removed for reasons indicated in Note P.
- R Includes functional wages & salaries billed by AEP Service Corporation for support of the operating company.
- S Long Term Debt cost rate = long-term interest (In 153) / long term debt (In 162). Preferred Stock cost rate = preferred dividends (In 154) / preferred outstanding (In 163). Common Stock cost rate (ROE) = 11.49%, the rate accepted by FERC in Docket No. ER08-1329. It includes an additional 50 basis points for PJM RTO membership. In the Projected & Historic templates, the interest expense on long-term debt is the sum of a full year's interest expense at the coupon rate for each issuance outstanding as of December 31 of the historic year. The projected expense for variable rate debt will be based on the effective rate at December 31. These conventions ensure that the expense used in the projection will reflect a full year, similar to the actual expense that will appear in the subsequent true-up of the projection, and minimize the impact on the true-up of using a partial year interest expense. The projection will reflect the actual historic-year expense recorded for issuance expenses, discounts and premiums, and gains or losses on reacquired debt. Eligible hedging gains or losses will be limited to five basis points of the projected capital structure. Details and calculations are shown on Worksheet L.
- The Long Term Debt balance for I&M includes the accumulated balance of principle and related interest for Spent Nuclear Fuel Disposal Costs collected prior to April 7, 1983. This total balance of \$265,249,280 at 12/31/12 is not included in the balance in line 162 above.
- U This note only applies to the true-up template.

INDIANA MICHIGAN POWER COMPANY

Line No.						Tr	ansmission Amount
166	REVENUE REQUIREMENT (w/o incentives)	(In 303)	Total	۸	llocator		\$120,627,861
167	REVENUE CREDITS	(Note A) (Worksheet E)	947,294	DA	1.00000	\$	947,294
168	REVENUE REQUIREMENT For All Company Facilities	(In 166 less In 167)				\$	119,680,567
	The Carrying Charge Calculations on lines 171 to 176 be ission Enhancement Charges. The total non-incentive re	_ · · · · · · · · · · · · · · · · · · ·	_				
169	Not applicable on this template						
170 171 172	NET PLANT CARRYING CHARGE w/o intra-AEP charges Annual Rate Monthly Rate	or credits or ROE incentives (Note B) ((In 166 - In 270 - In 271)/ In 213 x 100) (In 171 / 12)					17.57% 1.46%
173 174	NET PLANT CARRYING CHARGE ON LINE 171, w/o dep Annual Rate	reciation or ROE incentives (Note B) ((In 166 - In 270 - In 271 - In 276) / In 213 x 100)					14.93%
175 176	NET PLANT CARRYING CHARGE ON LINE 174, w/o Retu Annual Rate	urn, income taxes or ROE incentives (Note B) ((In 166 - In 270 - In 271 - In 276 - In 298 - In 299)) / In 213 x 100)				4.83%
177	Not applicable on this template						
178		REVENUE REQUIREMENT FOR S	SCHEDULE 1A CHARGES				
179 180 181	Total Load Dispatch & Scheduling (Account 561) Less: Load Dispatch - Scheduling, System Control and Dis Less: Load Dispatch - Reliability, Planning & Standards De						8,132,792 5,531,795 1,083,397
182	Total 561 Internally Developed Costs	(Line 179 - Line 180 - Line 181)					1,517,600

INDIANA MICHIGAN POWER COMPANY

(1) (2) (3)

		Data Sources				Total
Line	RATE BASE CALCULATION	(See "General Notes")	<u>TO Total</u> <u>NOTE C</u>	Alloc	<u>eator</u>	<u>Transmission</u>
No.	GROSS PLANT IN SERVICE		<u></u>			
183	Production	(Worksheet A In 1.C)	4,037,746,725	NA	0.00000	-
184	Less: Production ARO (Enter Negative)	(Worksheet A In 2.C)	(303,665,963)	NA	0.00000	<u>-</u>
185	Transmission	(Worksheet A In 3.C & Ln 307)	1,278,027,455	DA	0.044=0	1,207,351,314
186	Less: Transmission ARO (Enter Negative)	(Worksheet A In 4.C& Ln 308)	- N/A	TP	0.94470	N/A
187 188	Plus: Transmission Plant-in-Service Additions (Works Plus: Additional Trans Plant on Transferred Assets (Works)	,	N/A N/A	NA NA	0.00000 0.00000	N/A N/A
189	Distribution	(Worksheet A In 5.C)	1,553,155,453	NA NA	0.00000	IV/A
190	Less: Distribution ARO (Enter Negative)	(Worksheet A In 6.C)	-	NA	0.00000	_
191	General Plant	(Worksheet A In 7.C)	107,811,687	W/S	0.04206	4,534,307
192	Less: General Plant ARO (Enter Negative)	(Worksheet A In 8.C)	(172,922)	W/S	0.04206	(7,273)
193	Intangible Plant	(Worksheet A In 9.C)	139,775,289	W/S	0.04206	5,878,622
194	TOTAL GROSS PLANT	(sum Ins 183 to 193)	6,812,677,724	GP(h)= GTD=	0.178749 0.42645	1,217,756,970
195	ACCUMULATED DEPRECIATION AND AMORTIZATIO	N		G1D=	0.42043	
196	Production	(Worksheet A In 12.C)	2,318,062,105	NA	0.00000	-
197	Less: Production ARO (Enter Negative)	(Worksheet A In 13.C)	(84,627,053)	NA	0.00000	-
198	Transmission	(Worksheet A In 14.C & 28.C)	537,188,312	TP1=	0.96948	520,792,956
199	Less: Transmission ARO (Enter Negative)	(Worksheet A In 15.C)		TP1=	0.96948	
200	Plus: Transmission Plant-in-Service Additions (Works	sheet I)	N/A	DA	1.00000	N/A
201	Plus: Additional Projected Deprec on Transferred Ass	· · · · · · · · · · · · · · · · · · ·	N/A	DA	1.00000	N/A
202	Plus: Additional Transmission Depreciation for 2013		N/A	TP1	0.96948	N/A
203	Plus: Additional General & Intangible Depreciation for		N/A	W/S	0.04206	N/A
204	Plus: Additional Accum Deprec on Transferred Assets	,	N/A	DA	1.00000	N/A
205	Distribution	(Worksheet A In 16.C)	479,335,470	NA	0.00000	-
206	Less: Distribution ARO (Enter Negative)	(Worksheet A In 17.C)	-	NA W/O	0.00000	-
207	General Plant ABO (Enter Negative)	(Worksheet A In 18.C)	27,301,514	W/S	0.04206	1,148,238
208 209	Less: General Plant ARO (Enter Negative) Intangible Plant	(Worksheet A In 19.C) (Worksheet A In 20.C)	(138,294) 132,615,751	W/S W/S	0.04206 0.04206	(5,816) 5,577,508
210	TOTAL ACCUMULATED DEPRECIATION	(sum Ins 196 to 209)	3,409,737,805	VV/O	0.04200	527,512,886
210		(30111113 130 to 203)	5,405,757,005			321,312,000
211	NET PLANT IN SERVICE	(1, 400, 1, 404, 1, 400, 1, 40 7)	4 500 045 540			
212	Production	(ln 183 + ln 184 - ln 196 - ln 197)	1,500,645,710			-
213 214	Transmission Plus: Transmission Plant-in-Service Additions (In 187)	(ln 185 + ln 186 - ln 198 - ln 199)	740,839,143 N/A			686,558,358 N/A
214	Plus: Additional Trans Plant on Transferred Assets (II	,	N/A			N/A
216	Plus: Additional Transmission Depreciation for 2013	,	N/A			N/A
217	Plus: Additional General & Intangible Depreciation for		N/A			N/A
218	Plus: Additional Accum Deprec on Transferred Assets		N/A			N/A
219	Distribution	(ln 189 + ln 190 - ln 205 - ln 206)	1,073,819,983			-
220	General Plant	(ln 191 + ln 192 - ln 207 - ln 208)	80,475,545			3,384,613
221	Intangible Plant	(ln 193 - ln 209)	7,159,538			301,113
222	TOTAL NET PLANT IN SERVICE	(sum Ins 212 to 221)	3,402,939,919	NP(h)=	0.202838	690,244,084
000		(N. C. P.)				
223	DEFERRED TAX ADJUSTMENTS TO RATE BASE	(Note D)	(246 295)	NΙΛ		
224 225	Account No. 281.1 (enter negative) Account No. 282.1 (enter negative)	(Worksheet B, In 2 & In 5.C) (Worksheet B, In 7 & In 10.C)	(246,285) (920,003,284)	NA DA		- (151,405,593)
226	Account No. 283.1 (enter negative)	(Worksheet B, In 12 & In 15.C)	(664,464,895)	DA		(9,424,522)
227	Account No. 190.1	(Worksheet B, In 17 & In 20.C)	755,767,692	DA		15,048,413
228	Account No. 255 (enter negative)	(Worksheet B, In 24 & In 25.C)	-	DA		-
229	TOTAL ADJUSTMENTS	(sum Ins 224 to 228)	(828,946,772)			(145,781,702)
230	PLANT HELD FOR FUTURE USE	(Worksheet A In 29.C & In 30.C)	6,294,968	DA		208,360
231	REGULATORY ASSETS	(Worksheet A In 36. (C))	-	DA		-
232	WORKING CAPITAL	(Note E)				
233	Cash Working Capital	(1/8 * In 253)	2,257,790			2,132,932
234	Transmission Materials & Supplies	(Worksheet C, In 2.(D))	1,954,137	TP	0.94470	1,846,071
235	A&G Materials & Supplies	(Worksheet C, In 3.(D))	52,111	W/S	0.04206	2,192
236	Stores Expense	(Worksheet C, In 4.(D))	-	GP(h)	0.17875	-
237	Prepayments (Account 165) - Labor Allocated	(Worksheet C, In 6.G)	144,686,210	W/S	0.04206	6,085,164
238	Prepayments (Account 165) - Gross Plant	(Worksheet C, In 6.F)	5,571,844	GP(h)	0.17875	995,960
239	Prepayments (Account 165) - Transmission Only	(Worksheet C, In 6.E)	(400,407,040)	DA	1.00000	-
240	Prepayments (Account 165) - Unallocable	(Worksheet C, In 6.D)	(139,407,819)	NA	0.00000	44.000.040
241	TOTAL WORKING CAPITAL	(sum Ins 233 to 240)	15,114,273			11,062,318
242	IPP CONTRIBUTIONS FOR CONSTRUCTION	(Note F) (Worksheet D, In 7.B)	(2,810,348)	DA	1.00000	(2,810,348)
243	RATE BASE (sum Ins 222, 229, 230, 231, 241, 242)		2,592,592,040			552,922,712
						<u></u>

INDIANA MICHIGAN POWER COMPANY

(1) (2) (3)

Lino	EXPENSE, TAXES, RETURN & REVENUE REQUIREMENTS CALCULATION	Data Sources (See "General Notes")	TO Total	Alloc	ator	Total <u>Transmission</u>
Line No.	OPERATION & MAINTENANCE EXPENSE					
244	Production	321.80.b	1,354,855,751			
245	Distribution	322.156.b	54,052,769			
246	Customer Related Expense	322 & 323.164,171,178.b	39,354,797			
247	Regional Marketing Expenses	322.131.b	5,602,674			
248	Transmission	321.112.b	40,026,099			
249	TOTAL O&M EXPENSES	(sum Ins 244 to 248)	1,493,892,090			
250 251	Less: Total Account 561 Less: Account 565	(Note G) (Worksheet F, In 12.C) (Note H) 321.96.b	8,132,792 13,667,883			
252	Less: Regulatory Deferrals & Amortizations	(Note I) (Worksheet F, In 4.C)	163,108			
253	Total O&M Allocable to Transmission	(Ins 248 - 250 - 251 - 252)	18,062,316	TP	0.94470	17,063,453
		,				, ,
254	Administrative and General	323.197.b (Note J)	127,509,877			
255	Less: Acct. 924, Property Insurance	323.185.b	4,407,050			
256	Acct. 9260039 PBOP Expense	PBOP Worksheet O Line 9 & 10, (Note K)	9,791,529			
257 258	Acct. 9260057 PBOP Medicare Subsidy PBOP Expense Billed From AEPSC	PBOP Worksheet O Line 11, (Note K) PBOP Worksheet O Line 13, (Note K)	- 795,128			
259	Acct. 928, Reg. Com. Exp.	323.189.b	13,085,376			
260	Acct. 920, Reg. Com. Exp.	323.191.b	276,915			
261	Acct. 930.2, Misc. Gen. Exp.	323.192.b	5,318,780			
262	Balance of A & G	(In 254 - sum In 255 to In 261)	93,835,099	W/S	0.04206	3,946,485
263	Plus: Acct. 924, Property Insurance	(In 255)	4,407,050	GP(h)	0.17875	787,754
264	Acct. 928 - Transmission Specific	Worksheet F In 17.(E) (Note L)	-	TP	0.94470	-
265	Acct 930.1 - Only safety related ads -Direct	Worksheet F In 32.(E) (Note L)	-	TP	0.94470	-
266	Acct 930.2 - Misc Gen. Exp Trans	Worksheet F In 40.(E) (Note L)	184,289	DA	1.00000	184,289
267	Settlement Approved PBOP Recovery	PBOP Worksheet O, Col. C, Line 3, (Note M)	12,453,006	W/S	0.04206	523,744
268	A & G Subtotal	(sum Ins 262 to 267)	110,879,444			5,442,272
260	O 8 M EVDENCE CLIDTOTAL	(ln 252 + ln 260)	120 044 760			22 505 725
269 270	O & M EXPENSE SUBTOTAL Plus: TEA Settlement in Account 565	(In 253 + In 268) Company Records (Note H)	128,941,760	DA	1.00000	22,505,725
270 271	Plus: Transmission Lease Payments To Affiliates in Ac	· · · · · · · · · · · · · · · · · · ·		DA	1.00000	- -
272	TOTAL O & M EXPENSE	(ln 269 + ln 270 + ln 271)	128,941,760	DA	1.00000	22,505,725
	101712 0 0 111 21102	(200 2. 0 2. 1)	120,0 11,1 00			22,000,120
273	DEPRECIATION AND AMORTIZATION EXPENSE					
274	Production	336.2-6.f	67,479,165	NA	0.00000	-
275	Distribution	336.8.f	38,889,909	NA TD:	0.00000	-
276	Transmission	336.7.f	18,714,918	TP1	0.96948	18,143,726
277 278	Plus: Transmission Plant-in-Service Additions (Worksh	336.10.f	N/A 3,466,837	W/S	0.04206	N/A
276 279	General Intangible	336.1.f	15,123,027	W/S	0.04206	145,807 636,039
280	TOTAL DEPRECIATION AND AMORTIZATION	(Ln 274+275+	143,673,856	W/O	0.04200	18,925,572
_00		276+277+278+279)	. 10,010,000			.0,020,0.2
281	TAXES OTHER THAN INCOME	(Note N)				
282	Labor Related					
283	Payroll	Worksheet H In 22.(D)	12,399,142	W/S	0.04206	521,479
284	Plant_Related					
285	Property	Worksheet H In 22.(C) & In 47.(C)	46,385,973	DA	0.00000	8,974,114
286 287	Gross Receipts/Sales & Use Other	Worksheet H In 22.(F)	12,850,498	NA CD(b)	0.00000 0.17875	201 151
287 288	TOTAL OTHER TAXES	Worksheet H In 22.(E) (sum Ins 283 to 287)	1,628,831 73,264,444	GP(h)	0.17675	291,151 9,786,744
200	TOTAL OTTILIX TAXES	(30111 1113 203 to 201)	73,204,444			3,700,744
289	INCOME TAXES	(Note O)				
290	T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =	· · · ·	38.80%			
291	EIT=(T/(1-T)) * (1-(WCLTD/WACC)) =		44.13%			
292	where WCLTD=(In 327) and WACC = (In 330)					
293	and FIT, SIT & p are as given in Note O.					
294	GRCF=1 / (1 - T) = (from In 290)	(554 444 1 40)	1.6341			
295	Amortized Investment Tax Credit (enter negative)	(FF1 p.114, ln 19.c)	(4,502,458)			
296	Income Tax Calculation	(In 291 * In 299)	101,658,795			21,680,795
290 297	ITC adjustment	(In 294 * In 295)	(7,357,258)	NP(h)	0.20284	(1,492,328)
298	TOTAL INCOME TAXES	(sum Ins 296 to 297)	94,301,537	141 (11)	0.20201	20,188,467
		(63 200 30 201)	2 3,2 2 3,2 2 3			
299	RETURN ON RATE BASE (Rate Base*WACC)	(In 243 * In 330)	230,373,655			49,131,843
300	INTEREST ON IPP CONTRIBUTION FOR CONST. (Note	F) (Worksheet D, In 2.(B))	89,510	DA	1.00000	89,510
301	(Gains) / Losses on Sales of Plant Held for Future Use (W	orksheet N, In 4, Cols. ((F) & (H))	-			-
302	Tax Impact on Net Loss / (Gain) on Sales of Plant Held fo	or Future Use (In 301 * In291)	-			-
- -	. , ,	, ,				
303	TOTAL REVENUE REQUIREMENT		670,644,762			120,627,861
	(sum Ins 272, 280, 288, 298, 299, 300, 301, 302)					

INDIANA MICHIGAN POWER COMPANY

SUPPORTING CALCULATIONS

ln								
No.	TRANSMISSION PLANT INCLUDED IN PJM TARIFF							
304	Total transmission plant	(In 185)						1,278,027,455
305	Less transmission plant excluded from PJM Tariff (Note	P)						
306	Less transmission plant included in OATT Ancillary Servi	ces (Worksheet A, In 23, Col. (C	C)) (Note Q)					70,676,141
307	Transmission plant included in PJM Tariff	(In 304 - In 305 - In 306)					_	1,207,351,314
308	Percent of transmission plant in PJM Tariff	(In 307 / In 304)					TP=	0.94470
				Payroll Billed from				
309	WAGES & SALARY ALLOCATOR (W/S)	(Note R)	Direct Payroll	AEP Service Corp.	Total			
310	Production	354.20.b	129,153,471	10,365,139	139,518,610	NA	0.0000	-
311	Transmission	354.21.b	4,770,177	3,227,159	7,997,336	TP	0.94470	7,555,076
312	Regional Market Expenses	354.22.b	0	0	-	NA	0.0000	-
313	Distribution	354.23.b	19,070,176	2,341,225	21,411,401	NA	0.0000	-
314	Other (Excludes A&G)	354.24,25,26.b	5,951,661	4,757,127	10,708,788	NA	0.00000	<u>-</u>
315	Total	(sum Ins 310 to 314)	158,945,485	20,690,650	179,636,135			7,555,076
316	Transmission related amount						W/S=	0.04206
317	WEIGHTED AVERAGE COST OF CAPITAL (WACC)							\$
318	Long Term Interest	(Worksheet L, In. 26, col. (D))					91,995,574
319	Preferred Dividends	(Worksheet L, In. 31, col. (D)	•					-
320	Development of Common Stock:	(11 611 611 611 611 611 621 621	,					
321	Proprietary Capital	(FF1 p 112, Ln 16.c)						1,803,774,755
322	Less: Preferred Stock	(FF1 p 112, Ln 3.c)						-
323	Less: Account 216.1	(FF1 p 112, Ln 12 .c)						(104,879)
324	Less: Account 219	(FF1 p 112, Ln 15.c)						(28,884,204)
325	Common Stock	(ln 321 - ln 322 - ln 323 - ln 3	24)				_	1,832,763,838
			,				Cost	, ,,
326				\$	%		(Note S)	Weighted
327	Long Term Debt (Note T) Worksheet L, In 26, col. (B))		•	1,572,429,608	46.18%		0.0585	0.0270
328	Preferred Stock (In 322)			- · · · · · -	0.00%		-	0.0000
329	Common Stock (În 325)			1,832,763,838	53.82%		11.49%	0.0618
330	Total (Sum Ins 327 to 329)		•	3,405,193,446			WACC=	0.0889
	·							

INDIANA MICHIGAN POWER COMPANY

Notes

<u>Letter</u>

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

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

See Worksheet E for details.

- B The annual and monthly net plant carrying charges on page 1 are used to compute the revenue requirement for RTEP sponsored upgrades or those projects receiving approved incentive-ROE's.
- C Transmission Plant balances in this study are historic as of December 31, 2012.
- The total-company balances shown for Accounts 281, 282, 283, 190 only reflect ADIT that relates to utility operations. The balance of Account 255 is reduced by prior flow throughs and is completely excluded if the utility chose to utilize amortization of tax credits against FIT expense. An exception to this is pre-1971 ITC balances, which are required to be taken as an offset to rate base. Account 281 is not allocated. In compliance with FERC Rulemaking RM02-7-000, Asset Retirement Obligation deferrals have been removed from ratebase. Transmission ADIT allocations are shown on WS B.

The company will not include the ADIT portion of deferred hedge gains and losses in rate base.

- Cash Working Capital assigned to transmission is one-eighth of O&M allocated to transmission, as shown on line 253. It excludes:
 - 1) Load Scheduling & Dispatch Charges in account 561 that are collected in the OATT Ancilliary Services Revenue, as shown on line 250.
 - 2) AEP transmission equalization transfers, as shown on line 251
- 3) The impact of state regulatory deferrals and amortizations, as shown on line 252
- 4) All A&G Expenses, as shown on line 268.
- F Consistent with Paragraph 657 of Order 2003-A, the amount on line 242 is equal to the balance of IPP System Upgrade Credits owed to transmission customers that made contributions toward the construction of System upgrades, and includes accrued interest and unreturned balance of contributions. The annual interest expense is included on line 300.
- Removes from the cost of service the Load Scheduling and Dispatch expenses booked to accounts 561.1 through 561.8. Expenses recorded in these accounts, with the exception of 561.4 & 561.8 (lines 180 & 181 above) are recovered in Schedule 1A, OATT ancillary services rates. See Worksheet F, lines 3 through 12, for descriptions and the Form 1 Source of these accounts' balances.
- Removes cost of transmission service provided by others to determine the basis of cash working capital on line 253. To the extent such service is incurred to provide the PJM service at issue, e.g. transmission equalization agreement, such costs are added back on lines 270 and 271 to determine the total O&M collected in the formula. The amounts on lines 270 and 271 are also excluded in the calculation of the FCR percentage calculated on lines 170 through 176.
 - The addbacks on lines 270 and 271 of activity recorded in 565 represents inter-company sales or purchases of transmission capacity necessary to meet each AEP company's transmission load relative to their available transmission capacity.

The company records referenced on lines 270 and 271 is the INDIANA MICHIGAN POWER COMPANY general ledger.

- I Removes the impact of state regulatory deferrals or their amortization from O&M expense.
 - General Plant and Administrative & General expenses, other than in accounts 924, 928, and 930, will be functionalized based on the Wages & Salaries "W/S" allocator. The allocation basis for accounts 924, 928 and 930 are separately presented in the formula. A change in the allocation method for an account must be approved via a 205 filing with the FERC.
- K These deductions on lines 256 through 258 are to remove from the cost of service the expenses recorded by the company for Postemployment Benefits Other than Pensions (PBOP). See Note M below for the recoverable PBOP expense.
- Expenses reported for these A&G accounts will be included in the cost of service only to the extent they are directly assignable to transmission service. Worksheet F allocates these expense items. Acct 928 Includes Regulatory Commission expenses itemized in FERC Form-1 at page 351, column H. FERC Assessment Fees and Annual Charges shall not be allocated to transmission. Only safety-related and educational advertising costs in Account 930.1 are included in the TCOS. Account 930.2 includes the expenses incurred by the transmission function for Associated Business Development revenues given as a credit to the TCOS on Worksheet E.
- M See note K above. Per the settlement in Docket ER08-1329, recoverable PBOP expense is based on an annual total for the operating companies that is ratioed to them based on the total of actual annual PBOP costs, including charges from the AEP Service Corportation. The calculation of the recoverable amount for each company is shown on Worksheet O, and the process for updating the annual total is documented on Attachment F, Allowable PBOP Expense Formula.
- N Includes only FICA, unemployment, highway, property and other assessments charged in the current year. Gross receipts, sales & use and taxes related to income are excluded.
- O The currently effective income tax rate, where FIT is the Federal income tax rate; SIT is the State income tax rate, and p = the percentage of federal income tax deductible for state income taxes. See Worksheet G for the development of the Company's composite SIT.

 A utility that elected to utilize amortization of tax credits against taxable income, rather than book tax credits to Account No. 255 and reduce rate base, must reduce its income tax expense by the amount of the Amortized Investment Tax Credit (Form 1, 266.8.f)

 (In 295) multiplied by (1/1-T). If the applicable tax rates are zero enter 0.

Inputs Required:

FIT = 35.00%

SIT= 5.85% (State Income Tax Rate or Composite SIT. Worksheet G))

p = 0.00% (percent of federal income tax deductible for state purposes)

- P Removes plant excluded from the OATT because it does not meet the PJM's definition of Transmission Facilities or is otherwise ineligible to be recovered under the OATT.
- Q Removes transmission plant (e.g. step-up transformers) included in the development of OATT ancillary service rates and not already removed for reasons indicated in Note P.
- R Includes functional wages & salaries billed by AEP Service Corporation for support of the operating company.
- Long Term Debt cost rate = long-term interest (ln 318) / long term debt (ln 327). Preferred Stock cost rate = preferred dividends (ln 319) / preferred outstanding (ln 328).

 Common Stock cost rate (ROE) = 11.49%, the rate accepted by FERC in Docket No. ER08-1329. It includes an additional 50 basis points for remaining a member of the PJM RTO. In the Projected & Historic templates, the interest expense on long-term debt is the sum of a full year's interest expense at the coupon rate for each issuance outstanding as of December 31 of the historic year. The projected expense for variable rate debt will be based on the effective rate at December 31. These conventions ensure that the expense used in the projection will reflect a full year, similar to the actual expense that will appear in the subsequent true-up of the projection, and minimize the impact on the true-up of using a partial year interest expense. The projection will reflect the actual historic-year expense recorded for issuance expenses, discounts and premiums, and gains or losses on reacquired debt. Eligible hedging gains or losses will be limited to five basis points of the projected capital structure. Details and calculations are shown on Worksheet L.
- The Long Term Debt balance for I&M includes the accumulated balance of principle and related interest for Spent Nuclear Fuel Disposal Costs collected prior to April 7, 1983. This total balance of \$265,249,280 at 12/31/12 is not included in the balance in line 327 above.
- U This note only applies to the true-up template.

INDIANA MICHIGAN POWER COMPANY

Line No.						Т	ransmission Amount
1	REVENUE REQUIREMENT (w/o incentives)	(In 138)	Total	A II.			\$120,680,556
2	REVENUE CREDITS	(Note A) (Worksheet E)	Total 947,294	DA	1.00000	\$	947,294
3	REVENUE REQUIREMENT For All Company Facilities	(In 1 less In 2)				\$	119,733,262
	The Carrying Charge Calculations on lines 6 to 11 belo smission Enhancement Charges. The total non-incenti						
4	Revenue Requirement for PJM Schedule 12 Facilities (w	/o incentives) (Worksheet K)	1,323,753	DA	1.00000	\$	1,323,753
5	NET PLANT CARRYING CHARGE w/o intra-AEP charge	s or credits or ROE incentives (Note B)					
6	Annual Rate	((ln 1 - ln 105 - ln 106)/ ln 48 x 100)					17.76%
7	Monthly Rate	(ln 6 / 12)					1.48%
8	NET PLANT CARRYING CHARGE ON LINE 6, w/o depr	reciation or ROE incentives (Note B)					
9	Annual Rate	((ln 1 - ln 105 - ln 106 - ln 111) / ln 48 x 100)					15.10%
10	NET PLANT CARRYING CHARGE ON LINE 9, w/o Retui	rn, income taxes or ROE incentives (Note B)					
11	Annual Rate	((ln 1 - ln 105 - ln 106 - ln 111 - ln 133 - ln 134) / In 48 x 100)				4.92%
12	ADDITIONAL REVENUE REQUIREMENT for projects w/	incentive ROE's (Note B) (Worksheet K)					-
13		REVENUE REQUIREMENT FOR SCH	EDULE 1A CHARGES				
14	Total Load Dispatch & Scheduling (Account 561)	Line 85 Below					8,132,792
15	Less: Load Dispatch - Scheduling, System Control and D						5,531,795
16	Less: Load Dispatch - Reliability, Planning & Standards I						1,083,397
17	Total 561 Internally Developed Costs	(Line 14 - Line 15 - Line 16)					1,517,600

INDIANA MICHIGAN POWER COMPANY

	(1)	(2)	(3)		(4)	(5)
	RATE BASE CALCULATION	Data Sources (See "General Notes")	<u>TO Total</u>	Alle	ocator_	Total <u>Transmission</u>
Line No.	GROSS PLANT IN SERVICE		NOTE C			
18	Production	(Worksheet A In 1.E)	3,971,093,664	NA	0.00000	-
19	Less: Production ARO (Enter Negative)	(Worksheet A In 2.E)	(240,586,737)	NA	0.00000	-
20	Transmission	(Worksheet A In 3.E & Ln 142)	1,251,307,628	DA		1,196,024,411
21	Less: Transmission ARO (Enter Negative)	(Worksheet A In 4.E & Ln 143)		TP	0.95582	-
22	Plus: Transmission Plant-in-Service Additions (Wor	•	N/A	NA	0.00000	N/A
23	Plus: Additional Trans Plant on Transferred Assets	•	N/A	NA	0.00000	N/A
24 25	Distribution Loss: Distribution APO (Enter Negative)	(Worksheet A In 5.E) (Worksheet A In 6.E)	1,517,305,278	NA NA	0.00000 0.00000	<u>-</u>
26	Less: Distribution ARO (Enter Negative) General Plant	(Worksheet A III 6.E)	105,667,205	W/S	0.04255	4,496,430
27	Less: General Plant ARO (Enter Negative)	(Worksheet A In 8.E)	(179,651)	W/S	0.04255	(7,645)
28	Intangible Plant	(Worksheet A In 9.E)	138,975,304	W/S	0.04255	5,913,781
29	TOTAL GROSS PLANT	(sum Ins 18 to 28)	6,743,582,690	GP(h)= GTD=	0.17890 0.00000	1,206,426,977
30	ACCUMULATED DEPRECIATION AND AMORTIZATION	ON		0.5-	0.0000	
31	Production	(Worksheet A In 12.E)	2,289,818,877	NA	0.00000	-
32	Less: Production ARO (Enter Negative)	(Worksheet A In 13.E)	(81,929,364)	NA	0.00000	-
33	Transmission	(Worksheet A In 14.E & 28.E)	534,462,451	TP1=	0.96663	516,627,997
34	Less: Transmission ARO (Enter Negative)	(Worksheet A In 15.E)	<u> </u>	TP1=	0.96663	-
35	Plus: Transmission Plant-in-Service Additions (Wor	•	N/A	DA	1.00000	N/A
36	Plus: Additional Projected Deprec on Transferred A		N/A	DA	1.00000	N/A
37	Plus: Additional Transmission Depreciation for 2013		N/A	TP1	0.96663	N/A
38	Plus: Additional General & Intangible Depreciation f Plus: Additional Accum Deprec on Transferred Asse	· · · · · · · · · · · · · · · · · · ·	N/A N/A	W/S DA	0.04255	N/A N/A
39 40	Distribution	(Worksheet A In 16.E)	478,125,362	NA	1.00000 0.00000	IN/A
41	Less: Distribution ARO (Enter Negative)	(Worksheet A III 16.E)	470,125,502	NA NA	0.00000	- -
42	General Plant	(Worksheet A In 18.E)	26,878,601	W/S	0.04255	1,143,758
43	Less: General Plant ARO (Enter Negative)	(Worksheet A In 19.E)	(141,892)	W/S	0.04255	(6,038)
44	Intangible Plant	(Worksheet A In 20.E)	130,178,936	W/S	0.04255	5,539,471
45	TOTAL ACCUMULATED DEPRECIATION	(sum Ins 31 to 44)	3,377,392,970			523,305,188
46	NET PLANT IN SERVICE					
47	Production	(ln 18 + ln 19 - ln 31 - ln 32)	1,522,617,414			-
48	Transmission	(ln 20 + ln 21 - ln 33 - ln 34)	716,845,178			679,396,414
49 50	Plus: Transmission Plant-in-Service Additions (In 22	,	N/A			N/A
50 51	Plus: Additional Trans Plant on Transferred Assets Plus: Additional Transmission Depreciation for 2013	•	N/A N/A			N/A N/A
52	Plus: Additional General & Intangible Depreciation f	·	N/A			N/A N/A
53	Plus: Additional Accum Deprec on Transferred Asse		N/A			N/A
54	Distribution	(ln 24 + ln 25 - ln 40 - ln 41)	1,039,179,916			-
55	General Plant	(ln 26 + ln 27 - ln 42 - ln 43)	78,750,845			3,351,065
56	Intangible Plant	(In 28 - In 44)	8,796,368			374,310
57	TOTAL NET PLANT IN SERVICE	(sum lns 47 to 56)	3,366,189,720	NP(h)=	0.20294	683,121,789
		(0.1				
58 50	DEFERRED TAX ADJUSTMENTS TO RATE BASE	(Note D)	(054.507)	NIA		
59 60	Account No. 281.1 (enter negative) Account No. 282.1 (enter negative)	(Worksheet B, In 2 & In 5.E) (Worksheet B, In 7 & In 10.E)	(254,527) (863,955,914)	NA DA		- (116 926 257)
61	Account No. 282.1 (enter negative)	(Worksheet B, In 12 & In 15.E)	(660,516,314)	DA		(146,826,257) (10,107,028)
62	Account No. 190.1	(Worksheet B, In 17 & In 20.E)	727,492,523	DA		15,457,493
63	Account No. 255 (enter negative)	(Worksheet B, In 24 & In 25.E)	, - , -	DA		-
64	TOTAL ADJUSTMENTS	(sum Ins 59 to 63)	(797,234,232)			(141,475,792)
65	PLANT HELD FOR FUTURE USE	(Worksheet A In 29.E & In 30.E)	7,013,691	DA		203,338
66	REGULATORY ASSETS	(Worksheet A In 36. (E))	-	DA		-
67	WORKING CAPITAL	(Note E)				
68	Cash Working Capital	(1/8 * In 88)	2,257,790			2,158,040
69	Transmission Materials & Supplies	(Worksheet C, In 2.F)	1,241,870	TP	0.95582	1,187,003
70	A&G Materials & Supplies	(Worksheet C, In 3.F)	88,427	W/S	0.04255	3,763
71	Stores Expense	(Worksheet C, In 4.(D))	<u>-</u>	GP(h)	0.17890	-
72 72	Prepayments (Account 165) - Labor Allocated	(Worksheet C, In 8.G)	141,807,875	W/S	0.04255	6,034,314
73 74	Prepayments (Account 165) - Gross Plant	(Workshoot C. In 8.F)	4,484,132	GP(h)	0.17890	802,211
74 75	Prepayments (Account 165) - Transmission Only Prepayments (Account 165) - Unallocable	(Worksheet C, In 8.E) (Worksheet C, In 8.D)	- (137,425,350)	DA NA	1.00000 0.00000	-
75 76	TOTAL WORKING CAPITAL	(sum lns 68 to 75)	12,454,742	IN	0.00000	10,185,331
		,		D 4	4.00000	
77	IPP CONTRIBUTIONS FOR CONSTRUCTION	(Note F) (Worksheet D, In 8 (B))	(2,765,593)	DA	1.00000	(2,765,593)
78	RATE BASE (sum Ins 57, 64, 65, 66, 76, 77)		2,585,658,328			549,269,073

INDIANA MICHIGAN POWER COMPANY

(1) (2) (3) (4)

Lina	EXPENSE, TAXES, RETURN & REVENUE REQUIREMENTS CALCULATION	Data Sources (See "General Notes")	TO Total	Alle	ocator_	Total <u>Transmission</u>
Line	OPERATION & MAINTENANCE EXPENSE					
<u>No.</u> 79		221 00 h	1 254 955 751			
	Production Distribution	321.80.b 322.156.b	1,354,855,751			
80 91			54,052,769 30,354,707			
81 82	Customer Related Expense	322.164,171,178.b	39,354,797			
o∠ 83	Regional Marketing Expenses Transmission	322.131.b 321.112.b	5,602,674			
			40,026,099			
84	TOTAL O&M EXPENSES	(sum Ins 79 to 83)	1,493,892,090			
85	Less: Total Account 561	(Note G) (Worksheet F, In 12.C)	8,132,792			
86	Less: Account 565	(Note H) 321.96.b	13,667,883			
87	Less: Regulatory Deferrals & Amortizations	(Note I) (Worksheet F, In 4.C)	163,108	TD	0.05500	47.004.040
88	Total O&M Allocable to Transmission	(Ins 83 - 85 - 86 - 87)	18,062,316	TP	0.95582	17,264,316
00		000 4071 (N. 4. 1)	107 500 077			
89	Administrative and General	323.197.b (Note J)	127,509,877			
90	Less: Acct. 924, Property Insurance	323.185.b	4,407,050			
91	Acct. 9260039 PBOP Expense	PBOP Worksheet O Line 9 & 10, (Note K)	9,791,529			
92	Acct. 9260057 PBOP Medicare Subsidy	PBOP Worksheet O Line 11, (Note K)	-			
93	PBOP Expense Billed From AEPSC	PBOP Worksheet O Line 13, (Note K)	795,128			
94	Acct. 928, Reg. Com. Exp.	323.189.b	13,085,376			
95	Acct. 930.1, Gen. Advert. Exp.	323.191.b	276,915			
96	Acct. 930.2, Misc. Gen. Exp.	323.192.b	5,318,780			
97	Balance of A & G	(In 89 - sum In 90 to In 96)	93,835,099	W/S	0.04255	3,992,941
98	Plus: Acct. 924, Property Insurance	(In 90)	4,407,050	GP(h)	0.17890	788,421
99	Acct. 928 - Transmission Specific	Worksheet F In 17.(E) (Note L)	, , , <u>-</u>	TP ´	0.94470	, -
100	Acct 930.1 - Only safety related ads -Direct	Worksheet F In 32.(E) (Note L)	_	TP	0.94470	-
101	Acct 930.2 - Misc Gen. Exp Trans	Worksheet F In 40.(E) (Note L)	184,289	DA	1.00000	184,289
102	Settlement Approved PBOP Recovery	PBOP Worksheet O, Col. C, Line 3, (Note M)	12,453,006	W/S	0.04255	529,910
	A & G Subtotal	(sum lns 97 to 102)	110,879,444	VV/O	0.04233	
103	A & G Subiolai	(Sum ins 97 to 102)	110,679,444			5,495,561
404	O A M EV/DENIOE OUDTOTAL	(1.00.1.400)	100 044 700		-	00.750.077
104	O & M EXPENSE SUBTOTAL	(ln 88 + ln 103)	128,941,760			22,759,877
105	Plus: TEA Settlement in Account 565	Company Records (Note H)	-	DA	1.00000	-
106	Plus: Transmission Lease Payments To Affiliates in A		<u>-</u>	DA	1.00000	
107	TOTAL O & M EXPENSE	(In 104 + In 105 + In 106)	128,941,760			22,759,877
108	DEPRECIATION AND AMORTIZATION EXPENSE					
109	Production	336.2-6.f	67,479,165	NA	0.00000	-
110	Distribution	336.8.f	38,889,909	NA	0.00000	-
111	Transmission	336.7.f	18,714,918	TP1	0.96663	18,090,421
112	Plus: Transmission Plant-in-Service Additions (Works	heet I)	N/A			N/A
113	General	336.10.f	3,466,837	W/S	0.04255	147,523
114	Intangible	336.1.f	15,123,027	W/S	0.04255	643,526
115	TOTAL DEPRECIATION AND AMORTIZATION	(Ln 109+110+	143,673,856	, •	• • • • • • • • • • • • • • • • • • • •	18,881,470
110	TOTAL DEFINEDITION AND AMORTIZATION	111+112+113+114)	140,070,000			10,001,470
116	TAXES OTHER THAN INCOME	(Note N)				
117	Labor Related	(Note N)				
117		Worksheet H In 22.(D)	12,399,142	W/S	0.04255	527,618
	Payroll	Worksheet Hill 22.(D)	12,399,142	W/S	0.04255	527,010
119	Plant Related	Washahaat II la 00 (0) 0 la 47 (0)	40 005 070	DΛ		0.074.444
120	Property	Worksheet H In 22.(C) & In 47.(C)	46,385,973	DA	0.00000	8,974,114
121	Gross Receipts/Sales & Use	Worksheet H In 22.(F)	12,850,498	NA OB(L)	0.00000	-
122	Other	Worksheet H In 22.(E)	1,628,831	GP(h)	0.17890	291,398
123	TOTAL OTHER TAXES	(sum lns 118 to 122)	73,264,444			9,793,130
	NOOME TAXES	(1) (0)				
124	INCOME TAXES	(Note O)				
125	T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =		38.80%			
126	EIT=(T/(1-T)) * (1-(WCLTD/WACC)) =		43.60%			
127	where WCLTD=(In 162) and WACC = (In 165)					
128	and FIT, SIT & p are as given in Note O.					
129	GRCF=1 / (1 - T) = (from ln 125)		1.6341			
130	Amortized Investment Tax Credit (enter negative)	(FF1 p.114, ln 19.c)	(4,502,458)			
- -		· ' '	(, - ,)			
131	Income Tax Calculation	(In 126 * In 134)	100,971,702			21,449,328
132	ITC adjustment	(In 129 * In 130)	(7,357,258)	NP(h)	0.20294	(1,493,054)
133	TOTAL INCOME TAXES	(sum Ins 131 to 132)	93,614,444	· · · ('')		19,956,274
100	1017/E HOOME 17/7/EO	(53111110 101 10 102)	50,017,7 77			10,000,214
134	RETURN ON RATE BASE (Rate Base*WACC)	(ln 78 * ln 165)	231,608,072			49,200,294
134	TETOTIN ON TATE DASE (TATE DASE WACC)	(III 70 III 100)	201,000,0 <i>1</i> 2			43,200,294
40E	INTEREST ON IDD CONTRIBUTION FOR CONST. (Nate	F) (Markehoot D. In 2 (P))	00 E40	DΛ	1 00000	00 E40
135	INTEREST ON IPP CONTRIBUTION FOR CONST. (Note	5 1) (VVUIKSHEEL D, III Z.(D))	89,510	DA	1.00000	89,510
400	(Going) / Lacons on Salas of Blant Hold for Fitting Hay	Norkshoot N. In 4. Cala. //E\ 9. (LIV)				
136	(Gains) / Losses on Sales of Plant Held for Future Use (V	VOIKSHEELIN, IN 4, COIS. ((F) & (H))	-			-
	T. I	C. F. (II // 100 † 1. 100)				
137	Tax Impact on Net Loss / (Gain) on Sales of Plant Held f	or Future Use (In 136 * In126)	-			-
		_				
138	TOTAL REVENUE REQUIREMENT	<u> </u>	671,192,086		=	120,680,556
	(sum lns 107, 115, 123, 133, 134, 135)					

INDIANA MICHIGAN POWER COMPANY

SUPPORTING CALCULATIONS

ln							
No.	TRANSMISSION PLANT INCLUDED IN PJM TARIFF						
139	Total transmission plant	(In 20)					1,251,307,628
140	Less transmission plant excluded from PJM Tariff (Note	·					-
141	Less transmission plant included in OATT Ancillary Serv	•	. (C)) (Note Q)				55,283,217
142	Transmission plant included in PJM Tariff	(ln 139 - ln 140 - ln 141)	,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,			_	1,196,024,411
143	Percent of transmission plant in PJM Tariff	(ln 142 / ln 139)				TP	0.95582
				Payroll Billed from			
144	WAGES & SALARY ALLOCATOR (W/S)	(Note R)	Direct Payroll	AEP Service Corp.	Total		
145	Production	354.20.b	129,153,471	10,365,139	139,518,610	NA 0.00000	-
146	Transmission	354.21.b	4,770,177	3,227,159	7,997,336	TP 0.95582	7,644,011
147	Regional Market Expenses	354.22.b	0	0	· -	NA 0.00000	<u>-</u>
148	Distribution	354.23.b	19,070,176	2,341,225	21,411,401	NA 0.00000	-
149	Other (Excludes A&G)	354.24,25,26.b	5,951,661	4,757,127	10,708,788	NA 0.00000	-
150	Total	(sum lns 145 to 149)	158,945,485	20,690,650	179,636,135	-	7,644,011
151	Transmission related amount					W/S=	0.04255
152	WEIGHTED AVERAGE COST OF CAPITAL (WACC)					_	\$
153	Long Term Interest	(Worksheet M, In. 21, col. (E	())			_	94,555,778
154	Preferred Dividends	(Worksheet M, In. 55, col. (E	(1)				-
155	Development of Common Stock:					_	Average
156	Proprietary Capital	(Worksheet M, In. 1, col. (E)))			_	1,782,377,444
157	Less: Preferred Stock	(Worksheet M, In. 2, col. (E)))				-
158	Less: Account 216.1	(Worksheet M, In. 3, col. (E)))				(167,822)
159	Less: Account 219	(Worksheet M, In. 4, col. (E)))			_	(28,552,807)
160	Common Stock	(ln 156 - ln 157 - ln 158 - ln 1	159)			_	1,811,098,073
		•	•	Capital Structure	Weighting	Cost	
161		Average \$		Actual	Cap Limit	(Note S)	Weighted
162	Long Term Debt (Note T) W/S M, In 11, In 22, col. (E))	1,567,678,557	•	46.40%	0.00%	0.0603	0.0280
163	Preferred Stock (In 157)	· · · · · · · · · · · · · · · · · · ·		0.00%	0.00%		0.0000
164	Common Stock (În 160)	1,811,098,073		53.60%	0.00%		0.0616
165	Total (Sum Ins 162 to 164)	3,378,776,629				WACC=	0.0896
166	Capital Structure Equity Limit (Note U)	100.0%					

INDIANA MICHIGAN POWER COMPANY

<u>Notes</u>

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

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

See Worksheet E for details.

- B The annual and monthly net plant carrying charges on page 1 are used to compute the revenue requirement for RTEP sponsored upgrades or those projects receiving approved incentive-ROE's.
- C Transmission Plant balances in this study reflect the average of the balances at December 31, 2011 and December 31, 2012.
- The total-company balances shown for Accounts 281, 282, 283, 190 only reflect ADIT that relates to utility operations. The balance of Account 255 is reduced by prior flow throughs and is completely excluded if the utility chose to utilize amortization of tax credits against FIT expense. An exception to this is pre-1971 ITC balances, which are required to be taken as an offset to rate base. Account 281 is not allocated. In compliance with FERC Rulemaking RM02-7-000, Asset Retirement Obligation deferrals have been removed from ratebase. Transmission ADIT allocations are shown on WS B.

The company will not include the ADIT portion of deferred hedge gains and losses in rate base.

- Cash Working Capital assigned to transmission is one-eighth of O&M allocated to transmission, as shown on line 88. It excludes:
 - 1) Load Scheduling & Dispatch Charges in account 561 that are collected in the OATT Ancilliary Services Revenue, as shown on line 85.
 - 2) AEP transmission equalization transfers, as shown on line 86
 - 3) The impact of state regulatory deferrals and amortizations, as shown on line 87
- 4) All A&G Expenses, as shown on line 103.
- Consistent with Paragraph 657 of Order 2003-A, the amount on line 77 is equal to the balance of IPP System Upgrade Credits owed to transmission customers that made contributions toward the construction of System upgrades, and includes accrued interest and unreturned balance of contributions. The annual interest expense is included on line 135.
- Removes from the cost of service the Load Scheduling and Dispatch expenses booked to accounts 561.1 through 561.8. Expenses recorded in these accounts, with the exception of 561.4 & 561.8 (lines 15 & 16 above) are recovered in Schedule 1A, OATT ancillary services rates. See Worksheet F, lines 3 through 12, for descriptions and the Form 1 Source of these accounts' balances.
- H Removes cost of transmission service provided by others to determine the basis of cash working capital on line 88. To the extent such service is incurred to provide the PJM service at issue, e.g. transmission equalization agreement, such costs are added back on lines 105 and 106 to determine the total O&M collected in the formula. The amounts on lines 105 and 106 are also excluded in the calculation of the FCR percentage calculated on lines 5 through 11.
 - The addbacks on lines 105 and 106 of activity recorded in 565 represents inter-company sales or purchases of transmission capacity necessary to meet each AEP company's transmission load relative to their available transmission capacity.

The company records referenced on lines 105 and 106 is the INDIANA MICHIGAN POWER COMPANY general ledger.

- Removes the impact of state regulatory deferrals or their amortization from O&M expense. applicable only for state regulatory purposes.
- J General Plant and Administrative & General expenses, other than in accounts 924, 928, and 930, will be functionalized based on the Wages & Salaries "W/S" allocator. The allocation basis for accounts 924, 928 and 930 are separately presented in the formula. A change in the allocation method for an account must be approved via a 205 filing with the FERC.
- K These deductions on lines 91 through 93 are to remove from the cost of service the expenses recorded by the company for Postemployment Benefits Other than Pensions (PBOP). See Note M below for the recoverable PBOP expense.
- Expenses reported for these A&G accounts will be included in the cost of service only to the extent they are directly assignable to transmission service. Worksheet F allocates these expense items. Acct 928 Includes Regulatory Commission expenses itemized in FERC Form-1 at page 351, column H. FERC Assessment Fees and Annual Charges shall not be allocated to transmission. Only safety-related and educational advertising costs in Account 930.1 are included in the TCOS. Account 930.2 includes the expenses incurred by the transmission function for Associated Business Development revenues given as a credit to the TCOS on Worksheet E.
- M See note K above. Per the settlement in Docket ER08-1329, recoverable PBOP expense is based on an annual total for the operating companies that is ratioed to them based on the total of actual annual PBOP costs, including charges from the AEP Service Corportation. The calculation of the recoverable amount for each company is shown on Worksheet O, and the process for updating the annual total is documented on Attachment F, Allowable PBOP Expense Formula.
- N Includes only FICA, unemployment, highway, property and other assessments charged in the current year. Gross receipts, sales & use and taxes related to income are excluded.
- O The currently effective income tax rate, where FIT is the Federal income tax rate; SIT is the State income tax rate, and p = the percentage of federal income tax deductible for state income taxes. See Worksheet G for the development of the Company's composite SIT. A utility that elected to utilize amortization of tax credits against taxable income, rather than book tax credits to Account No. 255 and reduce rate base, must reduce its income tax expense by the amount of the Amortized Investment Tax Credit (Form 1, 266.8.f) (In 130) multiplied by (1/1-T). If the applicable tax rates are zero enter 0.

Inputs Required:

FIT = 35.00%

SIT= 5.85% (State Income Tax Rate or Composite SIT. Worksheet G))

p = 0.00% (percent of federal income tax deductible for state purposes)

- P Removes plant excluded from the OATT because it does not meet the PJM's definition of Transmission Facilities or is otherwise ineligible to be recovered under the OATT.
- Q Removes transmission plant (e.g. step-up transformers) included in the development of OATT ancillary service rates and not already removed for reasons indicated in Note P.
- R Includes functional wages & salaries billed by AEP Service Corporation for support of the operating company.
- Long Term Debt cost rate = long-term interest (ln 153) / long term debt (ln 162). Preferred Stock cost rate = preferred dividends (ln 154) / preferred outstanding (ln 163). Common Stock cost rate (ROE) = 11.49%, the rate accepted by FERC in Docket No. ER08-1329. It includes an additional 50 basis points for PJM RTO membership. Interest expense for the true-up WACC is based on actual expenses for the true-up year. The amount of eligible hedging gains or losses included in total interest expense is limited to five basis points of the true-up capital structure. Details and calculations of the true-up weighted average cost of capital are shown on Worksheet M. Eligible Hedging Gains and Losses are defined in the Formula Protocols in the tariff. and on Worksheet M.
- The Long Term Debt balance for I&M includes the accumulated balance of principle and related interest for Spent Nuclear Fuel Disposal Costs collected prior to April 7, 1983.

 This total balance of \$265,249,280 at 12/31/12 is not included in the balance in line 162 above.
- Per Settlement, equity for INDIANA MICHIGAN POWER COMPANY is limited to 100% of Capital Structure. If the percentage of equity exceeds the cap, the excess is included in weighted percentage of long term debt in the capital structure.

 During the period ended December 31, 2011 the equity cap is in effect. During this period, a change in the cap percentage must be approved via a 205 filing with the FERC.

AEP East Companies Cost of Service Formula Rate Using 2012 FF1 Balances Worksheet A Supporting Plant Balances INDIANA MICHIGAN POWER COMPANY

Line	(A)	(B)	(C)	(D)	(E)				
Number	Rate Base Item & Supporting Balance	Source of Data	Balance @ December 31, 2012	Balance @ December 31, 2011	Average Balance for 2012				
	tional ARO investment and accumulated depreciation l								
Plant Investment Balances									
1	Production Plant In Service	FF1, page 205 Col.(g) & pg. 204 Col. (b), ln 46	4,037,746,725	3,904,440,602	3,971,093,664				
2	Production Asset Retirement Obligation (ARO)	FF1, page 205&204, Col.(g)&(b), Ins 15,24,34,44	303,665,963	177,507,511	240,586,737				
3	Transmission Plant In Service	FF1, page 207 Col.(g) & pg. 206 Col. (b), ln 58	1,278,027,455	1,224,587,801	1,251,307,628				
4	Transmission Asset Retirement Obligation	FF1, page 207 Col.(g) & pg. 206 Col. (b), ln 57	-	-	-				
5	Distribution Plant In Service	FF1, page 207 Col.(g) & pg. 206 Col. (b), ln 75	1,553,155,453	1,481,455,103	1,517,305,278				
6	Distribution Asset Retirement Obligation	FF1, page 207 Col.(g) & pg. 206 Col. (b), ln 74	-	-	-				
7	General Plant In Service	FF1, page 207 Col.(g) & pg. 206 Col. (b), ln 99	107,811,687	103,522,722	105,667,205				
8	General Asset Retirement Obligation	FF1, page 207 Col.(g) & pg. 206 Col. (b), ln 98	172,922	186,379	179,651				
9	Intangible Plant In Service	FF1, page 205 Col.(g) & pg. 204 Col. (b), ln 5	139,775,289	138,175,318	138,975,304				
10	Total Property Investment Balance	(Sum of Lines: 3, 1, 5, 7, 9)	7,116,516,609	6,852,181,546	6,984,349,078				
11	Total ARO Balance (included in total on line 10)	(Sum of Lines: 4, 2, 6, 8)	303,838,885	177,693,890	240,766,388				
<u>Accumulated</u>	Depreciation & Amortization Balances								
12	Production Accumulated Depreciation	FF1, page 219, lns 20-24, Col. (b)	2,318,062,105	2,261,575,648	2,289,818,877				
13	Production ARO Accumulated Depreciation	Company Records - Note 1	84,627,053	79,231,676	81,929,364				
14	Transmission Accumulated Depreciation	FF1, page 219, ln 25, Col. (b)	537,188,312	531,736,589	534,462,451				
15	Transmission ARO Accumulated Depreciation	Company Records - Note 1	-	-	-				
16	Distribution Accumulated Depreciation	FF1, page 219, ln 26, Col. (b)	479,335,470	476,915,254	478,125,362				
17	Distribution ARO Accumulated Depreciation	Company Records - Note 1	-	-	-				
18	General Accumulated Depreciation	FF1, page 219, ln 28, Col. (b)	27,301,514	26,455,688	26,878,601				
19	General ARO Accumulated Depreciation	Company Records - Note 1	138,294	145,489	141,892				
20	Intangible Accumulated Amortization	FF1, page 200, In 21, Col. (b)	132,615,751	127,742,121	130,178,936				
21	Total Accumulated Depreciation or Amortization	(Sum of Lines: 14, 12, 16, 18, 20)	3,494,503,152	3,424,425,300	3,459,464,226				
22	Total ARO Balance (included in total on line 21)	(Sum of Lines: 15, 13, 17, 19)	84,765,347	79,377,165	82,071,256				
Generation S	tep-Up Units								
23	GSU Investment Amount	Company Records - Note 1	70,676,141	39,890,293	55,283,217				
24	GSU Accumulated Depreciation	Company Records - Note 1	16,395,356	19,273,552	17,834,454				
25	GSU Net Balance	(Line 23 - Line 24)	54,280,785	20,616,741	37,448,763				
Transmission	Accumulated Depreciation Net of GSU Accumulated I	<u>Depreciation</u>							
26	Transmission Accumulated Depreciation	(Line 14 Above)	537,188,312	531,736,589	534,462,451				
27	Less: GSU Accumulated Depreciation	(Line 24 Above)	16,395,356	19,273,552	17,834,454				
28	Subtotal of Transmission Net of GSU	(Line 26 - Line 27)	520,792,956	512,463,037	516,627,997				
Plant Held Fo	or Future Use								
29	Plant Held For Future Use	FF1, page 214, ln 47, Col. (d)	6,294,968	7,732,413	7,013,691				
30	Transmission Plant Held For Future	Company Records - Note 1	208,360	198,316	203,338				
Regulatory A	ssets and Liabilities Approved for Recovery In Ratebas Note: Regulatory Assets & Liabilities can only be included								
31 32					-				
33 34					-				
35 36	Total Regulatory Deferrals Included in Ratebase		-	<u>.</u>					

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

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

AEP East Companies Cost of Service Formula Rate Using 2012 FF1 Balances Worksheet B Supporting ADIT and ITC Balances INDIANA MICHIGAN POWER COMPANY

	(A)	(B)	(C)	(D)	(E)
<u>Line</u> Number	<u>Description</u>	<u>Source</u>	Balance @ December 31, 2012	Balance @ December 31, 2011	Average Balance for 2012
1	Account 281				
2	Year End Utility Deferrals	FF1, p. 272 - 273, ln 8, Col. (k)	246,285	262,768	254,527
3	Less: ARO Related Deferrals	Company Records - Note 1	-	-	-
4	Less: Other Excluded Deferrals	Company Records - Note 1	246,285	262,768	254,527
5	Transmission Related Deferrals Ln 2 - ln 3 - ln 4		-	-	-
6	Account 282				
7	Year End Utility Deferrals	FF1, p. 274 - 275, ln 5, Col. (k)	920,003,284	807,908,544	863,955,914
8	Less: ARO Related Deferrals	Company Records - Note 1	79,547,117	34,707,660	57,127,389
9	Less: Other Excluded Deferrals	Company Records - Note 1	689,050,574	630,953,963	660,002,269
10	Transmission Related Deferrals	Ln 7 - ln 8 - ln 9	151,405,593	142,246,921	146,826,257
11	Account 283				
12	Year End Utility Deferrals	FF1, p. 276 - 277, ln 9, Col. (k)	664,464,895	656,567,733	660,516,314
13	Less: ARO Related Deferrals	Company Records - Note 1	489,889,606	451,069,253	470,479,430
14	Less: Other Excluded Deferrals	Company Records - Note 1	165,150,767	194,708,947	179,929,857
15	Transmission Related Deferrals	Ln 12 - In 13 - In 14	9,424,522	10,789,533	10,107,028
16	Account 190				
17	Year End Utility Deferrals	FF1, p. 234, ln 8, Col. (c)	755,767,692	699,217,353	727,492,523
18	Less: ARO Related Deferrals	Company Records - Note 1	569,810,510	486,599,089	528,204,800
19	Less: Other Excluded Deferrals	Company Records - Note 1	170,908,769	196,751,691	183,830,230
20	Transmission Related Deferrals	Ln 17 - In 18 - In 19	15,048,413	15,866,573	15,457,493
21	Account 255				
22	Year End ITC Balances	FF1, p. 266-267, ln 8, Col. (h)	48,130,448	52,632,906	50,381,677
23	Less: Balances Not Qualified for Ratebase	Company Records - Note 1	48,130,448	52,632,906	50,381,677
24	ITC Balances Includeable Ratebase	Ln 22 - In 23	-	-	-

Company Records - Note 1

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

NOTE 2 $\,$ ADIT balances should exclude balances related to hedging activity.

Transmission Related Deferrals

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AEP East Companies Cost of Service Formula Rate Using 2012 FF1 Balances Worksheet C Supporting Working Capital Rate Base Adjustments INDIANA MICHIGAN POWER COMPANY

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(1)	
			<u>Material</u>	s & Supplies						
<u>Line</u>				Balance @ December	Balance @ December	Average Balance for				
<u>umber</u>			Source	31, 2012	<u>31, 2011</u>	<u>2012</u>				
1										
2		Transmission Materials & Supplies	FF1, p. 227, ln 8, Col. (c) & (b)	1,954,137	529,602	1,241,870				
3		General Materials & Supplies	FF1, p. 227, ln 11, Col. (c) & (b)	52,111	124,743	88,427				
4		Stores Expense (Undistributed)	FF1, p. 227, ln 16, Col. (c) & (b)	0	0	-				
Prepayment Balance Summary										
			Average of	Excludable	100% Transmission	Transmission Plant	Transmission Labor	Total Included in Ratebase		
5			YE Balance	<u>Balances</u>	<u>Related</u>	<u>Related</u>	Related	(E)+(F)+(G)		
6		Totals as of December 31, 2012	10,850,235	(139,407,819)	0	5,571,844	144,686,210	150,258,054		
8		Totals as of December 31, 2011 Average Balance	6,883,076 8,866,656	(135,442,881) (137,425,350)	-	3,396,419 4,484,132	138,929,539 141,807,875	142,325,958 146,292,006		
			Prepayments Account 165 - E	<u> Balance @ 12/31/2</u>	<u>012</u> 100%	Transmission	Transmission	Total Included		
0	Acc No	Description	2012 VE Belence	Excludable	Transmission	Plant	Labor	in Ratebase	Evalenation	
9	Acc. No.	<u>Description</u>	<u>YE Balance</u>	<u>Balances</u>	<u>Related</u>	Related	Related	(E)+(F)+(G)	<u>Explanation</u>	
	1650001 165000212	Prepaid Insurance Prepaid Taxes	3,887,518 436,231	- 436,231		3,887,518		3,887,518	Plant Related Insurance Policies Prepaid Taxes	
	1650003	Prepaid Rents	3,369	3,369				-	River Transport	
	1650005 1650006	Prepaid Employee Benefits Other Prepayments	1,569 3,909,935	1,569 3,909,935				-	Benefits Generation Relates to EPRI dues	
15	1650009	Prepaid Carry Cost-Factored AR	47,917	47,917			444.000.040	-	AR Factoring - Retail Only	
	1650010 1650014	Prepaid Pension Benefits FAS 158 Qual Contra Asset	144,686,210 (144,686,210)	(144,686,210)			144,686,210	144,686,210 -	Prefunded Pension Expense SFAS 158 Offset	
18	165001112	Prepaid Sales Taxes	600,600	600,600			-	-	Prepaid Sales Tax - Distribution	
	165001212 1650021	Prepaid Use Taxes Prepaid Insurance - EIS	139,157 1,684,326	139,157 -		1,684,326	-	- 1.684.326	Prepaid Use Tax - Distribution Energy INS Services	
21 ′	1650022	Prepaid SNF Container Costs	0	-		, ,	-	, , , , <u>-</u>	-	
	1650023 1650026	Prepaid Lease Prepaid SNF Costs	139,613 0	139,613 -			-	-	Prepaid Leases	
		Subtotal - Form 1, p 111.57.c	10,850,235	(139,407,819)	0	5,571,844	144,686,210	150,258,054	-	
			Prepayments Account 165 - B	Salance @ 12/31/ 2	<u>2011</u> 100%	Transmission	Transmission	Total Included		
0.4	A N-	Parantation.	2011	Excludable	Transmission	Plant	Labor	in Ratebase	Fundamentan	
24	Acc. No.	<u>Description</u>	<u>YE Balance</u>	<u>Balances</u>	<u>Related</u>	<u>Related</u>	Related	<u>(E)+(F)+(G)</u>	<u>Explanation</u>	
	1650001 165000211	Prepaid Insurance Prepaid Taxes	2,257,087 312,823	- 312,823		2,257,087		2,257,087	Plant Related Insurance Policies Prepaid Taxes	
	165000211	Prepaid Rents	3,369	3,369			-	-	River Transport	
	1650005 1650006	Prepaid Employee Benefits Other Prepayments	4,578 34,988	4,578 34,988			-	-	Relates to EPRI dues	
30 ·	1650009	Other Prepayments Prepaid Carry Cost-Factored AR	62,687	62,687				-	AR Factoring - Retail Only	
	1650010 1650014	Prepaid Pension Benefits FAS 158 Qual Contra Asset	138,929,539 (138,929,539)	(139 020 520)			138,929,539	138,929,539	Prefunded Pension Expense SFAS 158 Offset	
33	165001111	Prepaid Sales Taxes	562,130	(138,929,539) 562,130			-	- -	OI VO 190 OIISEL	
34 <i>'</i>	165001211 1650021	Prepaid Use Taxes Prepaid Insurance - EIS	111,303 1,139,332	111,303		1,139,332	-	- 1,139,332		
36 ·	1650022	Prepaid SNF Container Costs	0	-		1,139,332	-	1,139,332		
37 ·	1650023 1650026	Prepaid Lease Prepaid SNF Costs	175,980 2,218,800	175,980 2,218,800			-	-		
30	1000020	Trapala SIMP Gusts	2,210,000	2,210,000						
		Subtotal - Form 1, p 111.57.d	6,883,076	(135,442,881)		3,396,419	138,929,539	142,325,958	-	
		,,,	5,225,210	(,, -, -,		-,,	- , , 3	,==2,000		

AEP East Companies Cost of Service Formula Rate Using 2012 FF1 Balances Worksheet D Supporting IPP Credits INDIANA MICHIGAN POWER COMPANY

<u>Line</u> <u>Number</u>	(A) <u>Description</u>	(B) <u>2012</u>
1	Net Funds from IPP Customers 12/31/2011 (2012 FORM 1, P269, line 6.b)	(2,720,838)
2	Interest Accrual (Company Records - Note 1)	(89,510)
3	Revenue Credits to Generators (Company Records - Note 1)	-
4 5 6	Other Adjustments Accounting Adjustment (Company Records - Note 1)	
7	Net Funds from IPP Customers 12/31/2012 (2012 FORM 1, P269, line 6.f)	(2,810,348)
8	Average Balance for Year as Indicated in Column B ((In 1 + In 7)/2)	(2,765,593)
Note 1	On this worksheet Company Records refers to INDIANA	

Ν MICHIGAN POWER COMPANY's general ledger.

AEP East Companies Cost of Service Formula Rate Using 2012 FF1 Balances Worksheet E Supporting Revenue Credits INDIANA MICHIGAN POWER COMPANY

<u>Line</u> Number	<u>Description</u>	<u>Total</u> Company	Non- Transmission	Transmission
1	Account 450, Forfeited Discounts (FF1 p.300.16.(b); Company Records - Note 1)	4,504,166	4,504,166	-
2	Account 451, Miscellaneous Service Revenues (FF1 p.300.17.(b); Company Records - Note 1)	3,366,681	3,309,894	56,787
3	Account 454, Rent from Electric Property (FF1 p.300.19.(b); Company Records - Note 1)	7,495,108	7,069,523	425,585
4	Account 4560015, Associated Business Development - (Company Records - Note 1)	1,609,822	1,176,732	433,090
5	Account 456 - Other Electric Revenues - (Company Records - Note 1)	37,512,337	37,480,505	31,832
6	Subtotal - Other Operating Revenues (Company Total equals (FF1 p. 300.26.(b))	54,488,114	53,540,820	947,294
7	Accounts 4470004 & 5, Revenues from Grandfathered Transmission Contracts -	-	-	-
8	(Company Records - Note 1) Total Other Operating Revenues To Reduce Revenue Requirement	54,488,114	53,540,820	947,294

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

AEP East Companies Cost of Service Formula Rate Using 2012 FF1 Balances Worksheet F Supporting Allocation of Specific O&M or A&G Expenses INDIANA MICHIGAN POWER COMPANY

	(A)	(B)	(C)	(D)	(E)	(F)
<u>Line</u>			<u>2012</u>	<u>100%</u>	100% Transmission	
<u>Number</u>	<u>Item No.</u>	<u>Description</u>	<u>Expense</u>	Non-Transmission	<u>Specific</u>	<u>Explanation</u>
1	500000	Regulatory O&M Deferrals & Amortizations	162 100			
2	5660000	Misc Transmission Expense Total	163,108 163,108			
_			100,100			
		Detail of Account 561 Per FERC Form 1				
3	FF1 p 321.84.b	561 - Load Dispatching	0			
4	FF1 p 321.85.b	561.1 - Load Dispatch - Reliability	17,920			
5	FF1 p 321.86.b	561.2 - Load Dispatch - Monitor & Operate Trans System	1,172,559			
6	FF1 p 321.87.b	561.3 - Load Dispatch - Trans Service & Scheduling	(246)			
7	FF1 p 321.88.b	561.4 - Scheduling, System Control & Dispatch	5,531,795			
8	FF1 p 321.89.b	561.5 - Reliability, Planning and Standards Development	327,367			
9	FF1 p 321.90.b	561.6 - Transmission Service Studies	0			
10	FF1 p 321.91.b	561.7 - Generation Interconnection Studies	0			
11	FF1 p 321.92.b	561.8 - Reliability, Planning and Standards Development Serv				
12		Total of Account 561	8,132,792			
		Account 928				
13	9280000	Regulatory Commission Exp	562	562	_	Miscellaneous Filing Support
14	9280001	Regulatory Commission Exp-Adm	11,887,446	11,887,446	-	Nuclear Regulatory Commission/FERC Hydro
15	9280002	Regulatory Commission Exp-Case	1,161,490	1,161,490	-	Indiana/Michigan Rate Cases
16	9280003	Rate Case Amortization	35,878	35,878		Indiana Rate Case
17		Total	13,085,376	13,085,376		-
		•	, ,	, ,		-
18	9301000	Account 930.1 General Advertising Expenses	35,272	35,272		
19	9301000	Newspaper Advertising Space	35,854	35,854	_	
20	9301002	Radio Station Advertising Time	32,901	32,901	_	
21	9301003	TV Station Advertising Time	1,100	1,100	_	
22	9301006	Spec Corporate Comm Info Proj	19,998	19,998	_	
23	9301007	Special Adv Space & Prod Exp	332	332	-	
24	9301008	Direct Mail and Handouts	10,800	10,800	-	
25	9301009	Fairs, Shows, and Exhibits	-	-	-	
26	9301010	Publicity	54,325	54,325	-	
27	9301011	Dedications, Tours, & Openings	6,410	6,410	-	
28 29	9301012 9301013	Public Opinion Surveys Movies Slide Films & Speeches	8,226	8,226	-	
30	9301013	Video Communications	- 58	58	-	
31	9301015	Other Corporate Comm Exp	71,640	71,640	_	
			11,010			
32		Total	276,916	276,916	-	- -
		Account 930.2				
33	9302000	Misc General Expenses	3,456,214	3,456,214		
34	9302003	Corporate & Fiscal Expenses	202,905	202,905		
35	9302004	Research, Develop&Demonstr Exp	6,800	6,800		
36	9302005	Nucl Fac Ins - Replice Engy Cst	930,795			
37	9302006	Assoc Business Development Materials Sold	26,708	26,708	0	
38	9302007	Assoc Business Development Exp	695,129		184,289	
39	9302458	AEPSC nonaffiliated expense	228	228		-
40		Total	5,318,779	5,134,490	184,289	
		•	-,,	2, . 2 ., . 0 0	,	-

Cost of Service Formula Rate Using 2012 FF1 Balances Worksheet G Supporting - Development of Composite State Income Tax Rate INDIANA MICHIGAN POWER COMPANY

Indiana Corporate Income Tax Rate Apportionment Factor - Note 2 Effective State Tax Rate	8.25% 54.70%	4.51%
Michigan Single Business Tax Rate Apportionment Factor - Note 2 Effective State Tax Rate	6.00% 13.30%	0.80%
West Virginia Corporation Income Tax Rate Apportionment Factor - Note 2 Effective State Tax Rate	7.75% 3.27%	0.25%
Ohio Franchise Tax Rate Phase-out Factor Note 1 Apportionment Factor - Note 2 Effective State Tax Rate	0.00% 0.00% 0.00%	0.00%
Kentucky Corporation Income Tax Rate Apportionment Factor - Note 2 Effective State Tax Rate	6.00% 1.83%	0.11%
Missouri Corporation Income Tax Rate Apportionment Factor - Note 2 Effective State Tax Rate	6.25% 0.02%	0.00%
Illinois Corporation Income Tax Rate Apportionment Factor - Note 2 Effective State Tax Rate	9.50% 1.90%	0.18%
Total Effective State Income Tax Rate		5.85%

- Note 1 The Ohio State Income Tax is being phased-out prorata over a 5 year period from 2005 through 2009. The taxable portion of income is 0% 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 Activites 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.

Cost of Service Formula Rate Using 2012 FF1 Balances
Worksheet H Supporting Taxes Other than Income
INDIANA MICHIGAN POWER COMPANY

	(A)	(B)	(C)	(D)	(E)	(F)
Line No.	Account	Total Company NOTE 1	Property	Labor	Other	Non-Allocable
1 2	Revenue Taxes Gross Receipts Tax	12,786,739				12,786,739
3	Real Estate and Personal Property Taxes					
4	Real and Personal Property - Michigan	29,333,515	29,333,515			
5	Real and Personal Property - Indiana	17,019,510	17,019,510			
6	Real and Personal Property - Other Jurisdictions	32,948	32,948			
7	Payroll Taxes					
8	Federal Insurance Contribution (FICA)	11,774,150		11,774,150		
9 10	Federal Unemployment Tax State Unemployment Insurance	52,982 572,010		52,982 572,010		
10	State Chempleyment modianes	372,313		072,010		
11	Production Taxes	14.440				11 110
12	State Severance Taxes	14,448				14,448
13	Miscellaneous Taxes					
14	State Business & Occupation Tax	-				-
15 16	State Public Service Commission Fees	1,610,995			1,610,995	
16 17	State Franchise Taxes State Lic/Registration Fee	16,696 1,140			16,696 1,140	
18	Misc. State and Local Tax	1,140			1,140	
19	Sales & Use	130,278				130,278
20	Federal Excise Tax	4,990				4,990
21	Michigan Single Business Tax	(85,957)				(85,957)
22	Total Taxes by Allocable Basis	73,264,444	46,385,973	12,399,142	1,628,831	12,850,498
	(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					
	<u> </u>	unctional Property Tax		Distribution	Conoral	Total
23	Functionalized Net Plant (Hist. TCOS, Lns 212 thru 222) MICHIGAN JURISDICTION	<u>Production</u> 1,500,645,710	<u>Transmsission</u> 740,839,143	<u>Distribution</u> 1,073,819,983	<u>General</u> 80,475,545	<u>Total</u> 3,395,780,381
24	Percentage of Plant in MICHIGAN JURISDICTION	64.23%	15.87%	19.63%	15.85%	
25	Net Plant in MICHIGAN JURISDICTION (Ln 23 * Ln 24)	963,906,886	117,557,033	210,764,884	12,758,460	1,304,987,263
26	Less: Net Value of Exempted Generation Plant	272,029,809				
27	Taxable Property Basis (Ln 25 - Ln 26)	691,877,077	117,557,033	210,764,884	12,758,460	1,032,957,454
28 29	Relative Valuation Factor Weighted Net Plant (Ln 27 * Ln 28)	691,877,077	100% 117,557,033	210,764,884	100% 12,758,460	
30	General Plant Allocator (Ln 29 / (Total - General Plant))	67.82%	117,537,033	20.66%	-100.00%	
31	Functionalized General Plant (Ln 30 * General Plant)	8,652,514	1,470,151	2,635,795	(12,758,460)	-
32	Weighted MICHIGAN JURISDICTION Plant (Ln 29 + 31)	700,529,591	119,027,185	213,400,679	(0)	1,032,957,454
33	Functional Percentage (Ln 32/Total Ln 32)	67.82%	11.52%	20.66%		
34	Functionalized Expense in MICHIGAN JURISDICTION INDIANA JURISDICTION	19,893,361	3,380,087	6,060,068		29,333,515
35	Percentage of Plant in INDIANA JURISDICTION	35.77%	84.13%	80.37%	84.15%	
36	Net Plant in INDIANA JURISDICTION (Ln 23 * Ln 35)	536,738,824	623,282,110	863,055,099	67,717,085	2,090,793,118
37	Less: Net Value of Exempted Generation Plant	124,507,515				, , ,
38	Taxable Property Basis (Ln 36 - Ln 37)	412,231,309	623,282,110	863,055,099	67,717,085	1,966,285,603
39	Relative Valuation Factor	100%	100%	100%	100%	
40	Weighted Net Plant (Ln 38 * Ln 39)	412,231,309	623,282,110	863,055,099	67,717,085	
41 42	General Plant Allocator (Ln 40 / (Total - General Plant)) Functionalized General Plant (Ln 41 * General Plant)	21.71% 14,703,237	<u>32.83%</u> 22,230,879	45.46% 30,782,969	-100.00% (67,717,085)	_
43	Weighted INDIANA JURISDICTION Plant (Ln 40 + 42)	426,934,546	645,512,989	893,838,068	(07,717,083)	1,966,285,603
44	Functional Percentage (Ln 43/Total Ln 43)	21.71%	32.83%	45.46%	•	, , , ,
45	Functionalized Expense in INDIANA JURISDICTION	3,695,403	5,587,344	7,736,763		17,019,510
46	Total Other Jurisdictions: (Line 6 * Net Plant Allocator)		6,683			32,948
47	Total Func. Property Taxes (Sum Lns 34, 45 46)	23,588,763	8,974,114	13,796,831		46,385,973

Cost of Service Formula Rate Using 2012 FF1 Balances Worksheet H-1 Form 1 Source Reference of Company Amounts on WS H INDIANA MICHIGAN POWER COMPANY

(D) (A) (B) (C) Line FERC FORM 1 **Total** Company No. Annual Tax Expenses by Type (Note 1) Tie-Back **FERC FORM 1 Reference** Revenue Taxes **Gross Receipts Tax** 12,786,739 (2,320)P.263 In 13 (i) 15,007,000 P.263 In 14 (i) (2,800,000) P.263 In 15 (i) 102,464 P.263.2 In 15 (i) 479,595 P.263.2 In 16 (i) Real Estate and Personal Property Taxes Real and Personal Property - Michigan 29,333,515 (62,706)P.263.1 ln 14 (i) 29,185,900 P.263.1 In 15 (i) (8,777)P.263.1 ln 17 (i) P.263.1 In 18 (i) 15,078 (3,980)P.263.1 In 20 (i) 208,000 P.263.1 ln 21 (i) Real and Personal Property - Indiana 17,019,510 1,366 P.263 In 22 (i) 4,220 P.263 ln 23 (i) (221,902) P.263 In 24 (i) 1,582,284 P.263 In 25 (i) 15,412,673 P.263 In 26 (i) (4,129)P.263 In 27 (i) 244,998 P.263 In 28 (i) Real and Personal Property - Other Jurisdictions 32,948 26,140 P.263 In 38 (i) 3,415 P.263.2 In 1 (i) P.263.2 In 2 (i) 3,393 Payroll Taxes Federal Insurance Contribution (FICA) 11,774,150 11,774,150 P.263 In 3 (i) 52,982 Federal Unemployment Tax 52,982 P.263 In 4 (i) 572,010 State Unemployment Insurance 197,606 P.263 In 12 (i) 383,230 P.263.1 ln 7 (i) (8,826)P.263.2 In 9 (i) **Production Taxes** 11 State Severance Taxes 14,448 Misc States - 2010 1,638 P.263.2 In 32 (i) P.263.2 ln 33 (i) Misc States 2012 12,810 Miscellaneous Taxes State Business & Occupation Tax State Public Service Commission Fees 1,610,995 625,647 P.263 In 20 (i) 635,491 P.263 In 21 (i) 205,324 P.263.1 In 8 (i) 144,533 P.263.1 ln 9 (i) State Franchise Taxes 16,696 (80,106)P.263.1 In 39(i) 96,802 P.263.1 In 40 (i) State Lic/Registration Fee 1,140 1,000 P.263.1 ln 24 (i) P.263.1 In 35 (i) 25 100 P.263.3 In 13 (i) P.263.3 In 14 (i) 15 Misc. State and Local Tax Sales & Use 21 130,278 15,783 P.263.1 In 10 (i) 114,495 P.263.1 ln 11 (i) Federal Excise Tax 4,990 4,990 P.263 In 6 (i) (85,957) Michigan Single Business Tax P.263.1 In 5 (i) (85,957) Total Taxes by Allocable Basis 73,264,444 73,264,444 (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.

Cost of Service Formula Rate Using 2012 FF1 Balances Worksheet I Supporting Transmission Plant in Service Additions INDIANA MICHIGAN POWER COMPANY

(A) (B) (C) (D) (E) (F) (G) (H)	(1)	(H) ((G)	(F)	(E)	(D)	(C)	(B)	(A)
---------------------------------	-----	-------	-----	-----	-----	-----	-----	-----	-------

I. Calculation of Composite Depreciation Rate

1	Transmission Plant @ Beginning of Historic Period (2012) (P.206, In 58,(b)):	1,224,587,801
2	Transmission Plant @ End of Historic Period (2012) (P.207, In 58,(g)):	1,278,027,455
3		2,502,615,256
4	Average Balance of Transmission Investment	1,251,307,628
5	Annual Depreciation Expense, Historic TCOS, In 276	18,714,918
6	Composite Depreciation Rate	1.50%
7	Round to 1.5% to Reflect a Composite Life of 67 Years	1.50%

II. Calculation of Property Placed in Service by Month and the Related Depreciation Expense

8	Month in Service	Сар	italized Balance	Composite Annual Depreciation Rate	Annual preciation	Мо	nthly Depreciation	No. Months Depreciation	First Year Depreciation Expense
9	January	\$	25,112,081	1.50%	\$ 376,681	\$	31,390	11	\$ 345,290
10	February	\$	2,916,885	1.50%	\$ 43,753	\$	3,646	10	\$ 36,460
11	March	\$	2,032,083	1.50%	\$ 30,481	\$	2,540	9	\$ 22,860
12	April	\$	2,239,773	1.50%	\$ 33,597	\$	2,800	8	\$ 22,400
13	May	\$	2,535,031	1.50%	\$ 38,025	\$	3,169	7	\$ 22,183
14	June	\$	2,237,822	1.50%	\$ 33,567	\$	2,797	6	\$ 16,782
15	July	\$	6,984,144	1.50%	\$ 104,762	\$	8,730	5	\$ 43,650
16	August	\$	2,964,338	1.50%	\$ 44,465	\$	3,705	4	\$ 14,820
17	September	\$	1,945,996	1.50%	\$ 29,190	\$	2,432	3	\$ 7,296
18	October	\$	4,187,006	1.50%	\$ 62,805	\$	5,234	2	\$ 10,468
19	November	\$	1,545,395	1.50%	\$ 23,181	\$	1,932	1	\$ 1,932
20	December	\$	2,154,053	1.50%	\$ 32,311	\$	2,693	0	\$ -
21	Investment	\$	56,854,607				Depr	eciation Expense	\$ 544,141

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 2013

		Estimated Cost (000's)	Month in Service
25 <u>Major Zonal Projects</u>26 TIMBall State University27	 Subtotal	\$4,376 4,376	Jul-13
28 PJM Socialized/Beneficiary Allocated Regional Projects			
29 30	Subtotal	\$0 \$0	

Cost of Service Formula Rate Using 2012 FF1 Balances Worksheet J Supporting Calculation of PROJECTED PJM RTEP Project Revenue Requirement Billed to Benefiting Zones INDIANA MICHIGAN POWER COMPANY

SUMMARY OF PROJECTED ANNUAL RTEP REVENUE REQUIREMENTS

PROJECTED YEAR

Rev Require

W Incentives

2.666.168 \$

Incentive Amounts

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

	<u>%</u>	<u>Cost</u>	Weighted cost
Long Term Debt	46.18%	5.85%	2.702%
Preferred Stock	0.00%	0.00%	0.000%
Common Stock	53.82%	11.49%	<u>6.184%</u>
		R =	8.886%

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

Rate Base (Projected TCOS, In 78)	590,307,606
R (from A. above)	8.886%
Return (Rate Base x R)	52,453,806

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

Return (from B. above)	52,453,806
Effective Tax Rate (Projected TCOS, In 126)	44.13%
Income Tax Calculation (Return x CIT)	23,146,704
ITC Adjustment	(1,492,328
Income Taxes	21,654,375

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, In 1)	125,959,874
T.E.A. & Lease Payments (Projected TCOS, Lns 105 & 106)	-
Return (Projected TCOS, In 134)	52,453,806
Income Taxes (Projected TCOS, In 133)	21,654,375
Annual Revenue Requirement Less TEA Charges Return and Taxes	51 851 692

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

Annual Revenue Requirement, Less TEA Charges, Return and Taxes	51,851,692
Return (from I.B. above)	52,453,806
Income Taxes (from I.C. above)	21,654,375
Annual Revenue Requirement, with Basis Point ROE increase	125,959,874
Depreciation (Projected TCOS, In 111)	<u> 18,143,726</u>
Annual Rev. Reg, w/ Basis Point ROE increase, less Depreciation	107,816,148

C. Determine FCR with hypothetical basis point ROE increase.

Net Transmission Plant (Projected TCOS, In 48) Annual Revenue Requirement, with Basis Point ROE increase FCR with Basis Point increase in ROE	686,558,358 125,959,874 18.35%
Annual Rev. Req, w / Basis Point ROE increase, less Dep.	107,816,148
FCR with Basis Point ROE increase, less Depreciation	15.70%
FCR less Depreciation (Projected TCOS, In 9)	<u>14.80%</u>
Incremental FCR with Basis Point ROE increase, less Depreciation	0.90%

III. Calculation of Composite Depreciation Rate

Transmission Plant @ Beginning of Historic Period (2012) (P.206, In 58,(b)):	1,224,587,801
Transmission Plant @ End of Historic Period (2012) (P.207, In 58,(g)):	1,278,027,455
Subtotal	2,502,615,256
Average Transmission Plant Balance for 2012	1,251,307,628
Annual Depreciation Rate (Projected TCOS, In 111)	18,714,918
Composite Depreciation Rate	1.50%
Depreciable Life for Composite Depreciation Rate	66.86
Round to nearest whole year	67

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

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

A. Base Plan Facilities

Facilities receiving incentives accepted by FERC in Docket No. (e.g. ER05-925-000)

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

Project Description:

RTEP ID: b0839 (Replace existing 450 MVA transformer at Twin Branch 345 / 138 kV with a 675 MVA transformer)

Details			
Investment	8,316,811	Current Year	2013
Service Year (yyyy)	2009	ROE increase accepted by FERC (Basis Points)	-
Service Month (1-12)	6	FCR w/o incentives, less depreciation	14.80%
Useful life	67	FCR w/incentives approved for these facilities, less dep.	14.80%
CIAC (Yes or No)	No	Annual Depreciation Expense	124,132

CUMULATIVE HISTORY OF PROJECTED ANNUAL REVENUE REQUIREMENTS:

1,272,484

1,272,484

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.

01110 (100 01 110)		7 tilliaal Boproolation i	l			12 1, 102	RTEP Projected	RTEP Projected	
							Rev. Req't.From	Rev. Reg't.From	
							Prior Year	Prior Year	
Investment	Beginning	Depreciation	Ending	RTEP Rev. Req't.	RTEP Rev. Req't.	Incentive Rev.	Template	Template	
Year	Balance	Expense	Balance	w/o Incentives	with Incentives **	Requirement ##	w/o Incentives	with Incentives **	
2009	8,316,811		8,254,745		1,283,913				
2010	8,254,745			1,327,605	1,327,605	-	\$ 1,408,114	\$ 1,408,114	
2011	8,130,614			1,309,231	1,309,231	-	\$ 1,487,355	\$ 1,487,355	
2012	8,006,482			1,290,857	1,290,857		\$ 1,319,695	\$ 1,319,695	
2013	7,882,351			1,272,484	1,272,484				
2014	7,758,219			1,254,110	1,254,110				
2015 2016	7,634,088 7,509,956			1,235,737 1,217,363	1,235,737 1,217,363				
2017	7,385,825			1,198,989	1,198,989				
2017	7,363,623			1,180,616	1,180,616				
2019	7,137,562		7,013,430	1,162,242	1,162,242				
2020	7,013,430			1,143,868	1,143,868				
2021	6,889,299			1,125,495	1,125,495				
2022	6,765,167			1,107,121	1,107,121				
2023	6,641,036			1,088,747	1,088,747				
2024	6,516,904			1,070,374	1,070,374				
2025	6,392,773			1,052,000	1,052,000				
2026	6,268,641				1,033,627				
2027	6,144,510	124,132	6,020,378	1,015,253	1,015,253	\$ -			
2028	6,020,378	124,132	5,896,247	996,879	996,879	\$ -			
2029	5,896,247	124,132	5,772,115	978,506	978,506				
2030	5,772,115			960,132	960,132				
2031	5,647,984			941,758	941,758				
2032	5,523,852			923,385	923,385				
2033	5,399,721			905,011	905,011				
2034	5,275,589			886,637	886,637				
2035	5,151,458				868,264				
2036	5,027,326			849,890	849,890				
2037	4,903,195			831,517	831,517				
2038	4,779,063			813,143	813,143				
2039	4,654,932				794,769				
2040 2041	4,530,800 4,406,669			776,396 758,022	776,396 758,022				
2041	4,282,537				739,648				
2042	4,158,405				721,275				
2044	4,034,274				702,901				
2045	3,910,142			684,527	684,527				
2046	3,786,011				666,154				
2047	3,661,879				647,780				
2048	3,537,748				629,407				
2049	3,413,616			611,033	611,033				
2050	3,289,485			592,659	592,659				
2051	3,165,353	124,132	3,041,222	574,286	574,286	\$ -			
2052	3,041,222				555,912				
2053	2,917,090				537,538				
2054	2,792,959			519,165	519,165				
2055	2,668,827			500,791	500,791				
2056	2,544,696			482,417	482,417				
2057	2,420,564			464,044	464,044				
2058	2,296,433			445,670	445,670				
2059	2,172,301				427,297				
2060	2,048,170			408,923	408,923				
2061	1,924,038			390,549 372,176	390,549 372,176				
2062 2063	1,799,907				372,176				
2064	1,675,775 1,551,644			353,802 335,428	353,802 335,428				
2065	1,427,512			317,055	317,055				
2065	1,303,381			298,681	298,681				
2067	1,179,249				280,307				
2068	1,055,118				261,934				
Project Totals	1,000,110	7 205 025	333,330	49 175 200	49 175 200	7			

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

Project Totals

7,385,825

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.

48,175,299

48,175,299

^{##} 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.

I & M 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: RTEP ID: b1465.2 (Replace the 100 MVAR 765 kV shunt reactor bank on Rockport - Jefferson 765 kV line with a 300 MVAR

Current Projected Year ARR92,625Current Projected Year ARR w/ Incentive92,625Current Projected Year Incentive ARR-

Details						
nvestment	600,000	Current Year				2013
ervice Year (yyyy)	2013	ROE increase accept	ted by FERC (Basis Po	ints)		-
ervice Month (1-12)	6	FCR w/o incentives, I	ess depreciation			14.80%
seful life	67	FCR w/incentives app	CR w/incentives approved for these facilities, less dep.			
IAC (Yes or No)	No	Annual Depreciation E	nual Depreciation Expense			

CIAC (Yes or No)	No	Annual Depreciation E	Expense	,		8,955
Investment Year	Beginning Balance	Depreciation Expense	Ending Balance	RTEP Rev. Req't. w/o Incentives	RTEP Rev. Req't. with Incentives **	Incentive Rev. Requirement ##
2013	600,000	4,478	595,522	92,625	92,625	\$ -
2014	595,522	8,955	586,567	95,777	95,777	\$ -
2015	586,567	8,955	577,612	94,452	94,452	\$ -
2016	577,612	8,955	568,657	93,126	93,126	\$.
2017	568,657	8,955	559,701	91,801	91,801	\$ _
2018	559,701	8,955	550,746	90,475	90,475	¢ _
2019	550,746	8,955	541,791	89,150	89,150	φ •
2020	541,791	8,955	532,836	87,824	87,824	¢ ·
2021	532,836	8,955	523,881	86,499	86,499	e -
2022	523,881	8,955	514,925	85,173	85,173	φ ¢
2022	514,925	8,955	505,970	83,848	83,848	φ -
2023		8,955			82,522	φ -
	505,970	-	497,015	82,522	•	φ -
2025	497,015	8,955	488,060	81,197	81,197	5 -
2026	488,060	8,955	479,104	79,871	79,871	5 -
2027	479,104	8,955	470,149	78,546	78,546	5 -
2028	470,149	8,955	461,194	77,220	77,220	5 -
2029	461,194	8,955	452,239	75,894	75,894	-
2030	452,239	8,955	443,284	74,569	74,569	-
2031	443,284	8,955	434,328	73,243	73,243	-
2032	434,328	8,955	425,373	71,918	71,918	-
2033	425,373	8,955	416,418	70,592	70,592	\$ -
2034	416,418	8,955	407,463	69,267	69,267	\$ -
2035	407,463	8,955	398,507	67,941	67,941	\$ -
2036	398,507	8,955	389,552	66,616	66,616	\$ -
2037	389,552	8,955	380,597	65,290	65,290	\$ -
2038	380,597	8,955	371,642	63,965	63,965	\$ -
2039	371,642	8,955	362,687	62,639	62,639	\$ -
2040	362,687	8,955	353,731	61,314	61,314	\$ -
2041	353,731	8,955	344,776	59,988	59,988	\$ -
2042	344,776	8,955	335,821	58,663	58,663	\$ -
2043	335,821	8,955	326,866	57,337	57,337	\$ -
2044	326,866	8,955	317,910	56,012	56,012	\$ -
2045	317,910	8,955	308,955	54,686	54,686	\$ -
2046	308,955	8,955	300,000	53,360	53,360	\$ -
2047	300,000	8,955	291,045	52,035	52,035	\$ -
2048	291,045	8,955	282,090	50,709	50,709	\$ -
2049	282,090	8,955	273,134	49,384	49,384	\$ -
2050	273,134	8,955	264,179	48,058	48,058	\$ -
2051	264,179	8,955	255,224	46,733	46,733	\$ -
2052	255,224	8,955	246,269	45,407	45,407	\$ -
2053	246,269	8,955	237,313	44,082	44,082	\$ -
2054	237,313	8,955	228,358	42,756	42,756	\$ -
2055	228,358	8,955	219,403	41,431	41,431	\$ -
2056	219,403	8,955	210,448	40,105	40,105	\$ -
2057	210,448	8,955	201,493	38,780	38,780	\$ -
2058	201,493	8,955	192,537	37,454	37,454	\$ -
2059	192,537	8,955	183,582	36,129	36,129	\$ -
2060	183,582	8,955	174,627	34,803	34,803	\$ -
2061	174,627	8,955	165,672	33,478	33,478	\$ -
2062	165,672	8,955	156,716	32,152	32,152	\$ -
2002	450.740	0,000	4.47.704	22,102	22,102	I 🖟

CUMULATIVE HISTORY	OF PROJECTED	ΔΝΝΙΙΔΙ	REVENUE F	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.

5	LIFE OF THE I	PROJECT.		
	RTEP Projected		RTEP Projected	
	Rev. Req't.From		Rev. Req't.From	
	Prior Year		Prior Year	
	Template		Template with Incentives **	
	w/o Incentives		with Incentives **	
	\$ 92,584		\$ 92,584	
1				

156,716

147,761

138,806

129,851

120,896

111,940

102,985

94,030

85,075

76,119

2063

2064

2065

2066

2067

2068

2069

2070

2071

2072

Project Totals

8,955

8,955

8,955

8,955

8,955

8,955

8,955

8,955

8,955

8,955

532,836

147,761

138,806

129,851

120,896

111,940

102,985

94,030

76,119

67,164

30,826

29,501

28,175

26,850

25,524

24,199

22,873

21,548

20,222

18,897

3,475,512

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.

30,826 \$

29,501 \$ 28,175 \$

26,850 \$

25,524 \$

24,199 \$

22,873 \$

21,548 \$

20,222 \$

18,897 \$

3,475,512

^{**} 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.

I & M 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:

RTEP ID: b1465.3 (Transpose the Rockport - Sullivan 765 kV line and the Rockport - Jefferson 765 kV line)

Current Projected Year ARR	1,301,059
Current Projected Year ARR w/ Incentive	1,301,059
Current Projected Year Incentive ARR	-

Details						
nvestment	8,370,424	Current Year				2013
Service Year (yyyy)	2013	ROE increase accepted by	FERC (Basis Po	ints)		-
Service Month (1-12)	5	FCR w/o incentives, less de	CR w/o incentives, less depreciation			
Jseful life	67	FCR w/incentives approved	for these facilitie	s, less dep.		14.80%
CIAC (Yes or No)	No	Annual Depreciation Expens	se			124,932

,						,	RTEP Projected
							Rev. Reg't.From
							Prior Year
Investment	Beginning	Depreciation	Ending	RTEP Rev. Reg't.	RTEP Rev. Reg't.	Incentive Rev.	Template
Year	Balance	Expense	Balance	w/o Incentives	with Incentives **	Requirement ##	w/o Incentives
2013							w/o incentives
	8,370,424	72,877	8,297,547	1,301,059	1,301,059	\$ -	
2014	8,297,547	8,955	8,288,592	1,235,812	1,235,812	-	
2015	8,288,592	8,955	8,279,637	1,234,486	1,234,486	-	
2016	8,279,637	8,955	8,270,682	1,233,161	1,233,161	-	
2017	8,270,682	8,955	8,261,726	1,231,835	1,231,835	\$ -	
2018	8,261,726	8,955	8,252,771	1,230,510	1,230,510	\$ -	
2019	8,252,771	8,955	8,243,816	1,229,184	1,229,184	\$ -	
2020	8,243,816	8,955	8,234,861	1,227,859	1,227,859	\$ -	
2021	8,234,861	8,955	8,225,905	1,226,533	1,226,533	\$ -	
2022	8,225,905	8,955	8,216,950	1,225,208	1,225,208	\$ -	
2023	8,216,950	8,955	8,207,995	1,223,882	1,223,882	\$ -	
2024	8,207,995	8,955	8,199,040	1,222,557	1,222,557	\$ -	
2025	8,199,040	8,955	8,190,084	1,221,231	1,221,231	\$ -	
2026	8,190,084	8,955	8,181,129	1,219,906	1,219,906	\$ -	
2027	8,181,129	8,955	8,172,174	1,218,580	1,218,580	\$ -	
2028	8,172,174	8,955	8,163,219	1,217,255	1,217,255	¢ _	
2029	8,163,219	8,955	8,154,264	1,215,929	1,215,929	\$ -	
	· · · ·					·	
2030	8,154,264	8,955	8,145,308	1,214,604	1,214,604	\$ -	
2031	8,145,308	8,955	8,136,353	1,213,278	1,213,278	-	
2032	8,136,353	8,955	8,127,398	1,211,952	1,211,952	-	
2033	8,127,398	8,955	8,118,443	1,210,627	1,210,627	\$ -	
2034	8,118,443	8,955	8,109,487	1,209,301	1,209,301	\$ -	
2035	8,109,487	8,955	8,100,532	1,207,976	1,207,976	\$ -	
2036	8,100,532	8,955	8,091,577	1,206,650	1,206,650	\$ -	
2037	8,091,577	8,955	8,082,622	1,205,325	1,205,325	\$ -	
2038	8,082,622	8,955	8,073,667	1,203,999	1,203,999	\$ -	
2039	8,073,667	8,955	8,064,711	1,202,674	1,202,674	\$ -	
2040	8,064,711	8,955	8,055,756	1,201,348	1,201,348	\$ -	
2041	8,055,756	8,955	8,046,801	1,200,023	1,200,023	\$ -	
2042	8,046,801	8,955	8,037,846	1,198,697	1,198,697	\$ -	
2043	8,037,846	8,955	8,028,890	1,197,372	1,197,372		
2044	8,028,890	8,955	8,019,935	1,196,046	1,196,046		
2045	8,019,935	8,955		1,194,721	1,194,721	\$ -	
			8,010,980		1,193,395		
2046	8,010,980	8,955	8,002,025	1,193,395		\$ -	
2047	8,002,025	8,955	7,993,070	1,192,070	1,192,070	-	
2048	7,993,070	8,955	7,984,114	1,190,744	1,190,744	-	
2049	7,984,114	8,955	7,975,159	1,189,418	1,189,418	-	
2050	7,975,159	8,955	7,966,204	1,188,093	1,188,093		
2051	7,966,204	8,955	7,957,249	1,186,767	1,186,767	\$ -	
2052	7,957,249	8,955	7,948,293	1,185,442	1,185,442	\$ -	
2053	7,948,293	8,955	7,939,338	1,184,116	1,184,116	\$ -	
2054	7,939,338	8,955	7,930,383	1,182,791	1,182,791	\$ -	
2055	7,930,383	8,955	7,921,428	1,181,465	1,181,465	\$ -	
2056	7,921,428	8,955	7,912,473	1,180,140	1,180,140	\$ -	
2057	7,912,473	8,955	7,903,517	1,178,814	1,178,814	\$ -	
2058	7,903,517	8,955	7,894,562	1,177,489	1,177,489	\$ -	
2059	7,894,562	8,955	7,885,607	1,176,163	1,176,163		
2060	7,885,607	8,955	7,876,652	1,174,838	1,174,838	\$ -	
2061	7,876,652	8,955	7,867,696	1,173,512	1,173,512		
2062	7,867,696	8,955	7,858,741	1,172,187	1,172,187	\$ -	
2063	7,858,741	8,955	7,849,786	1,170,861	1,170,861	\$ -	
2064	7,849,786	8,955	7,849,780	1,169,535	1,169,535	\$ -	
2064		8,955					
	7,840,831		7,831,876	1,168,210	1,168,210	\$ -	
2066	7,831,876	8,955	7,822,920	1,166,884	1,166,884	\$ -	
2067	7,822,920	8,955	7,813,965	1,165,559	1,165,559	-	
2068	7,813,965	8,955	7,805,010	1,164,233	1,164,233	-	
2069	7,805,010	8,955	7,796,055	1,162,908	1,162,908	-	
2070	7,796,055	8,955	7,787,099	1,161,582	1,161,582		
2071	7,787,099		7,778,144	1,160,257	1,160,257		
2072	7.778.144	8.955	7.769.189	1.158.931	1.158.931	\$ -	

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

þ	TEMPLATE BE	ELOW TO MAINTAIN	HISTORY OF PROJE	CTED ARRS OVER T	HE
4	LIFE OF THE	PROJECT.			
	RTEP Projected		RTEP Projected		
I	Rev. Req't.From		Rev. Req't.From		
	Prior Year		Prior Year		
	Template		Template		
1	w/o Incentives		with Incentives **		
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7,778,144

2072

Project Totals

8,955

601,235

7,769,189

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.

1,158,931 \$

71,945,985

1,158,931

71,945,985

^{**} 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 2012 FF1 Balances Worksheet K Supporting Calculation of TRUE-UP PJM RTEP Project Revenue Requirement Billed to Benefiting Zones INDIANA MICHIGAN POWER COMPANY

Page 1 of 4

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

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

ROE w/o incentives (True-Up TCOS, In 164) 11.49% Project ROE Incentive Adder 0 <==ROE Adder Cannot Exceed 100 Basis Points</p> 11.49% <== ROE Including Incentives Cannot Exceed 12.5% Until July 1, 2012 ROE with additional 0 basis point incentive Determine R (cost of long term debt, cost of preferred stock and equity percentage is from the True-Up TCOS, lns 162 through 164) Cost Weighted cost % 6.03% 2.799% Long Term Debt 46.40% 0.00% 0.000% Preferred Stock 0.00% Common Stock 53.60% 11.49% 6.159% 8.957%

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

 Rate Base (True-Up TCOS, ln 78)
 549,269,073

 R (from A. above)
 8.957%

 Return (Rate Base x R)
 49,200,294

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

 Return (from B. above)
 49,200,294

 Effective Tax Rate (True-Up TCOS, In 126)
 43.60%

 Income Tax Calculation (Return x CIT)
 21,449,328

 ITC Adjustment
 (1,493,054)

 Income Taxes
 19,956,274

II. Calculate Net Plant Carrying Charge Rate (Fixed Charge Rate or FCR) with hypothetical 0 basis point ROE increase.

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

Annual Revenue Requirement (True-Up TCOS, In 1)	120,680,556
T.E.A. & Lease Payments (True-Up TCOS, Lns 105 & 106)	-
Return (True-Up TCOS, In 134)	49,200,294
Income Taxes (True-Up TCOS, In 133)	19,956,274
Annual Revenue Requirement, Less TEA Charges,	51,523,987
Return and Taxes	

B. Determine Annual Revenue Requirement with hypothetical 0 basis point increase in ROE.

Annual Revenue Requirement, Less TEA Charges, Return and Taxes	51,523,987
Return (from I.B. above)	49,200,294
Income Taxes (from I.C. above)	19,956,274
Annual Revenue Requirement, with 0 Basis Point ROE increase	120,680,556
Depreciation (True-Up TCOS, In 111)	18,090,421
Annual Rev. Req, w/ 0 Basis Point ROE increase,	102,590,135
less Depreciation	

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

Net Transmission Plant (True-Up TCOS, In 48) Annual Revenue Requirement, with 0 Basis Point ROE increase FCR with 0 Basis Point increase in ROE	679,396,414 120,680,556 17.76%
Annual Rev. Req, w / 0 Basis Point ROE increase, less Dep.	102,590,135
FCR with 0 Basis Point ROE increase, less Depreciation	15.10%
FCR less Depreciation (True-Up TCOS, In 9)	<u>15.10%</u>
Incremental FCR with 0 Basis Point ROE increase,	0.00%
less Depreciation	

III. Calculation of Composite Depreciation Rate

Transmission Plant @ Beginning of Historic Period () (P.206, In 58,(b)):	1,224,587,801
Transmission Plant @ End of Historic Period () (P.207, In 58,(g)):	1,278,027,455
Subtotal	2,502,615,256
Average Transmission Plant Balance for	1,251,307,628
Annual Depreciation Rate (True-Up TCOS, In 111)	18,714,918
Composite Depreciation Rate	1.50%
Depreciable Life for Composite Depreciation Rate	66.86
Round to nearest whole year	67

TRUE-UP YEAR		Rev Re	•		
As F	Projected in Prior Year WS J	\$	1,412,279	\$ 1,412,279	\$ -
	Actual after True-up	\$	1,323,753	\$ 1,323,753	\$ -
	True-up of ARR For 2012		(88,526)	(88,526)	-

I & M 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)

49,555,343

49,555,343

Project Description:

RTEP ID: b0839 (Replace existing 450 MVA transformer at Twin Branch 345 / 138 kV with a 675 MVA transformer)

Details 2012 8,316,811 Current Year Investment 9 ROE increase accepted by FERC (Basis Points) Service Year (yyyy) Service Month (1-12) FCR w/o incentives, less depreciation 15.10% Useful life 67 FCR w/incentives approved for these facilities, less dep. 15.10% CIAC (Yes or No) No Annual Depreciation Expense 124,132

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 ##
2009	8,316,811	62,066	8,254,745	8,285,778	1,313,234	1,313,234	\$ -
2010	8,254,745	124,132	8,130,614	8,192,679	1,361,242	1,361,242	\$ -
2011	8,130,614	124,132	8,006,482	8,068,548	1,342,497	1,342,497	\$ -
2012	8,006,482	124,132	7,882,351	7,944,416	1,323,753	1,323,753	\$ -
2013	7,882,351	124,132	7,758,219	7,820,285	1,305,009	1,305,009	\$ -
2014	7,758,219	124,132	7,634,088	7,696,153	1,286,265	1,286,265	\$ -
2015	7,634,088	124,132	7,509,956	7,572,022	1,267,521	1,267,521	\$ -
2016	7,509,956	124,132	7,385,825	7,447,890	1,248,777	1,248,777	\$ -
2017	7,385,825	124,132	7,261,693	7,323,759	1,230,033	1,230,033	\$ -
2018	7,261,693	124,132	7,137,562	7,199,627	1,211,289	1,211,289	\$ -
2019	7,137,562	124,132	7,013,430	7,075,496	1,192,545	1,192,545	\$ -
2020	7,013,430	124,132	6,889,299	6,951,364	1,173,801	1,173,801	-
2021	6,889,299	124,132	6,765,167	6,827,233	1,155,057	1,155,057	-
2022	6,765,167	124,132	6,641,036	6,703,101	1,136,312	1,136,312	-
2023	6,641,036	124,132	6,516,904	6,578,970	1,117,568	1,117,568	-
2024	6,516,904	124,132	6,392,773	6,454,838	1,098,824	1,098,824	-
2025	6,392,773	124,132	6,268,641	6,330,707	1,080,080	1,080,080	-
2026	6,268,641	124,132	6,144,510	6,206,575	1,061,336	1,061,336	-
2027	6,144,510	124,132	6,020,378	6,082,444	1,042,592	1,042,592	-
2028	6,020,378	124,132	5,896,247	5,958,312	1,023,848	1,023,848	-
2029	5,896,247	124,132	5,772,115	5,834,181	1,005,104	1,005,104	-
2030	5,772,115	124,132	5,647,984	5,710,049	986,360	986,360	-
2031	5,647,984	124,132	5,523,852	5,585,918	967,616	967,616	-
2032	5,523,852	124,132	5,399,721	5,461,786	948,872	948,872	-
2033	5,399,721	124,132	5,275,589	5,337,655	930,127	930,127	-
2034	5,275,589	124,132	5,151,458	5,213,523	911,383	911,383	-
2035	5,151,458	124,132	5,027,326	5,089,392	892,639	892,639	-
2036	5,027,326	124,132	4,903,195	4,965,260	873,895	873,895	-
2037	4,903,195	124,132	4,779,063	4,841,129	855,151	855,151	-
2038	4,779,063	124,132	4,654,932	4,716,997	836,407	836,407	-
2039	4,654,932	124,132	4,530,800	4,592,866	817,663	817,663	\$ -
2040	4,530,800	124,132	4,406,669	4,468,734	798,919	-	-
2041	4,406,669	124,132	4,282,537	4,344,603	780,175	780,175	
2042	4,282,537	124,132	4,158,405	4,220,471	761,431	761,431	\$ -
2043	4,158,405	124,132	4,034,274	4,096,340	742,687	742,687	\$ -
2044	4,034,274	124,132	3,910,142	3,972,208	723,942	723,942	\$ •
2045	3,910,142	124,132	3,786,011	3,848,077	705,198	705,198	-
2046	3,786,011	124,132 124,132	3,661,879	3,723,945	686,454	686,454 667,710	\$ - \$ -
2047	3,661,879	124,132 124,132	3,537,748	3,599,814	667,710	648,966	\$ -
2048 2049	3,537,748	124,132	3,413,616	3,475,682	648,966	630,222	\$ -
	3,413,616		3,289,485	3,351,551	630,222		
2050 2051	3,289,485 3,165,353	124,132 124,132	3,165,353 3,041,222	3,227,419 3,103,288	611,478 592,734	611,478 592,734	\$ - \$ -
2051	3,165,353	124,132 124,132	2,917,090	2,979,156	592,734 573,990	592,734 573,990	\$ -
2052	2,917,090	124,132		2,855,025	573,990 555,246	573,990 555,246	\$ -
2053 2054	2,917,090 2,792,959	124,132 124,132	2,792,959 2,668,827	2,855,025	536,502	536,502	\$ - \$ -
2054	2,792,959	124,132	2,544,696	2,730,693	517,757	517,757	\$ -
2056	2,544,696	124,132	2,420,564	2,482,630	499,013	499,013	\$ -
2057	2,420,564	124,132	2,420,364	2,358,499	480,269	480,269	\$ -
2057	2,420,564 2,296,433	124,132 124,132	2,296,433	2,358,499	461,525	480,269 461,525	\$ -
2059	2,290,433	124,132	2,048,170	2,110,236	442,781	442,781	\$ -
2060	2,172,301	124,132	1,924,038	1,986,104	424,037	424,037	\$ -
2061	1,924,038	124,132	1,799,907	1,861,973	405,293	405,293	\$ -
2062	1,799,907	124,132 124,132	1,675,775	1,737,841	386,549	386,549	\$ -
2062	1,675,775	124,132	1,551,644	1,613,710	367,805	367,805	\$ -
2064	1,551,644	124,132	1,427,512	1,489,578	349,061	349,061	\$ -
2065	1,427,512	124,132 124,132	1,303,381	1,365,447	330,317	349,061	\$ -
2066	1,427,512	124,132 124,132	1,179,249	1,241,315	311,572	311,572	\$ -
2067	1,303,361	124,132 124,132	1,055,118	1,117,184	292,828	292,828	\$ -
2068	1,179,249	124,132	930,986	993,052	274,084	274,084	- \$ -
Project Totals	1,000,110	7 205 025	330,300	993,U3Z	40 555 343	40 555 242	Ψ -

2012	Rev Require	W Incentives	Incentive Amounts
Prior Yr Projected	1,319,695	1,319,695	-
Prior Yr True-Up	1,323,753	1,323,753	-
True-Up Adjustment	4,058	4,058	-

Page 2 of 4

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

		ISTORY OF TRUED-U	P ARRS OVER THE	
LIFE OF THE P	ROJECT.			
RTEP Projected		RTEP Projected		
Rev. Req't.From	RTEP Rev Req't	Rev. Req't.From	RTEP Rev Req't	True-up of
Prior Year WS J	True-up	Prior Year WS J	True-up	Incentive
w/o Incentives	w/o Incentives	with Incentives **	with Incentives **	with Incentives **
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\$ 1,487,355	\$ (144,858)		\$ (144,858)	
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\$ 1,319,695	\$ 4,058	\$ 1,319,695	\$ 4,058	-
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Project Totals

7,385,825

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

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

I & M 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

Details

Investment

Facilities receiving incentives accepted by FERC in Docket No.

Current Year

(e.g. ER05-925-000)

2013

Project Description:

RTEP ID: b1465.2 (Replace the 100 MVAR 765 kV shunt reactor bank on Rockport - Jefferson 765 kV line with a 300 MVAR bank at Rockport Station)

2013	Rev Require	W Incentives	Incentive Amounts
Prior Yr Projected	92,584	92,584	-
Prior Yr True-Up	-	-	-
True-Up Adjustment	(92,584)	(92,584)	-

Page 3 of 4

Service Year (yyyy) Service Month (1-12) Useful life CIAC (Yes or No)	6 67	ROE increase accepte FCR w/o incentives, le FCR w/incentives app Annual Depreciation E	ess depreciation roved for these facilities				- 15.10% 15.10% -	INPUT TRUE-U TEMPLATE BE LIFE OF THE F	ORY OF TRUED-UP A JP ARR (WITH & WITH LOW TO MAINTAIN H PROJECT.	OUT INCENTIVES) FF ISTORY OF TRUED-U	ROM EACH PRIOR YE	AR
Investment	Beginning	Depreciation	Ending	Average	RTEP Rev. Req't.	RTEP Rev. Req't.	Incentive Rev.	RTEP Projected Rev. Req't.From Prior Year WS J	RTEP Rev Req't	RTEP Projected Rev. Req't.From Prior Year WS J	RTEP Rev Req't True-up	True-up of Incentive
Year	Balance	Expense	Balance	Balance	w/o Incentives	with Incentives **	Requirement ##	w/o Incentives	w/o Incentives	with Incentives **	with Incentives **	with Incentives **
2013 2014]	_	_	_	\$ -	\$ 92,584	\$ (92,584)	\$ 92,584	\$ (92,584) \$	\$ - \$ -
2015	_	_	_	_	_	_	\$ -		-		\$ -	\$ -
2016	-	-	-	-	-	-	\$ -		\$ -		\$ -	\$ -
2017	-	-	-	-	-	-	\$ -		\$ -		\$ -	\$ -
2018	-	-	-	-	-	-	\$ -		\$ -		\$ -	\$ -
2019	-	-	-	-	-	-	-		-		-	\$ -
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Project Totals		-			-	-	-					

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

Page 32 of 38

TRUE UP OF PROJECT REVENUE REQUIREMENT FOR PRIOR YEAR:

^{##} 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.

I & M 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:** RTEP ID: b1465.3 (Transpose the Rockport - Sullivan 765 kV line and the Rockport - Jefferson 765 kV line)

2013	Rev Require		W Incentives		Incentive Amoui	nts
Prior Yr Projected		-		-		-
Prior Yr True-Up		-		-		-
True-Up Adjustment		-		-		-

Page 4 of 4

Details 2013 Investment 2013 ROE increase accepted by FERC (Basis Points) Service Year (yyyy) Service Month (1-12) 5 FCR w/o incentives, less depreciation 15.10% 67 FCR w/incentives approved for these facilities, less dep. Useful life 15.10% CIAC (Yes or No) No Annual Depreciation Expense

CIAC (Yes or No)	NO	Annual Depreciation E	:xpense				-	LIFE OF THE P	ROJECT.			
Investment	Beginning	Depreciation	Ending	Average	RTEP Rev. Req't.	RTEP Rev. Req't.	Incentive Rev.	RTEP Projected Rev. Req't.From Prior Year WS J	RTEP Rev Req't True-up	RTEP Projected Rev. Req't.From Prior Year WS J	RTEP Rev Req't True-up	True-up of Incentive
Year	Balance	Expense	Balance	Balance	w/o Incentives	with Incentives **	Requirement ##	w/o Incentives	w/o Incentives	with Incentives **	with Incentives **	with Incentives 3
2013	-	-	-	-	-	-	\$ -		\$ -		\$ -	\$ -
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2016	-	-	-	-	-	-	-		-		-	-
2017	-	-	-	-	-	-	-		\$ -		\$ -	-
2018	-	-	-	-	-	-	-		-		\$ -	\$ -
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Project Totals

2071 2072 I & M WS K TRUE-UP RTEP RR Page 33 of 38

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.

TRUE UP OF PROJECT REVENUE REQUIREMENT FOR PRIOR YEAR:

LIFE OF THE P	ROJECT.			
RTEP Projected		RTEP Projected		
Rev. Req't.From	RTEP Rev Req't	Rev. Req't.From	RTEP Rev Req't	True-up of
Prior Year WS J	True-up	Prior Year WS J	True-up	Incentive
w/o Incentives	w/o Incentives	with Incentives **	with Incentives **	with Incentives **
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^{**} This is the total amount that needs to be reported to PJM for billing to all regions.

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

AEP East Companies Cost of Service Formula Rate Using 2012 FF1 Balances Worksheet L Supporting Projected Cost of Debt INDIANA MICHIGAN POWER COMPANY

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

Lina	(A)	(B)	(C)	(D)	(E)
<u>Line</u> Number	<u>Issuance</u>	Principle Outstanding	Interest Rate	Annual Expense (See Note S on Projected Template)	<u>Notes</u>
1	Long Term Debt (FF1.p. 256-257.h)			rojecteu rempute	
2 3	Advances From Associated Co.	-	5.375%	-	
4	Installment Purchase Contracts (FF1.p. 256	-257.h, a)			
5	PCRB Lawrenceburg In Series I	25,000,000	0.110%	27,500	
6	PCRB Lawrenceburg In Series H	52,000,000	0.130%	67,600	
7	PCRB - Rockport In Series D	40,000,000	5.250%	2,100,000	
8	PCRB - Rockport In 2002 Series A	50,000,000	4.625%	2,312,500	
9	PCRB - Rockport In 2009 Series A	50,000,000	6.250%	3,125,000	
10	PCRB - Rockport In 2009 Series B	50,000,000	6.250%	3,125,000	
11	Senior Unsecured Notes - Series F	175,000,000	5.050%	8,837,500	
12	Senior Unsecured Notes - Series G	125,000,000	5.650%	7,062,500	
13	Senior Unsecured Notes - Series H	400,000,000	6.050%	24,200,000	
14	Senior Unsecured Notes - Series I	475,000,000	7.000%	33,250,000	
15 16	Fort Wayne Settlement Multiple Draw Term Loan	20,429,608 110,000,000	6.000%	1,225,776	
17	Multiple Draw Term Loan	110,000,000	1.720%	1,892,000	
18	Issuance Discount, Premium, & Expenses:				
19	Auction Fees	FF1.p. 256 & 257.Lines Described as	Fees	-	
20	Allowable Hedge Amortization (See Ln 36 Beld	ow)		916,010	
21	Amort of Debt Discount and Expenses	FF1.p. 117.63.c		2,372,191	
22	Amort of Debt Premimums (Enter Negative)	FF1.p. 117.65.c		-	
23	Reacquired Debt:				
24	Amortization of Loss	FF1.p. 117.64.c		1,483,709	
25	Amortization of Gain	FF1.p. 117.66.c		(1,712)	
			_		
26	Total Interest on Long Term Debt	1,572,429,608	5.85%	91,995,574	
27	Preferred Stock (FF1.p. 250-251)	Preferred Shares Outstanding			
28	4.125% Series - \$100 - 55,257 Shares O/S	-	4.13%		
29	4.56% Series - \$100 - 14,412 Shares O/S	_	4.56%		
30	4.12% Series - \$100 - 11,055 Shares O/S	<u>.</u>	4.12%	-	
31	Dividends on Preferred Stock	-	0.00%	-	
32	Net Total Hedge Gains and Losses (WS M, L	n 34, (E))		916,010	
33	Total Projected Capital Structure Balance for 2	, \ //		3,405,193,446	
34	Financial Hedge Recovery Limit - Five Basis	Points of Total Capital		0.0005	
35	Limit of Recoverable Amount			1,702,597	
36	Recoverable Hedge Amortization (Lesser o	f Ln 32 or Ln 35)		916,010	

AEP East Companies Transmission Cost of Service Formula Rate INDIANA MICHIGAN POWER COMPANY

Worksheet M Supporting Calculation of Capital Structure and Weighted Average Cost of Capital Based on Average of Balances At 12/31/2011 & 12/31/2012

(A)	(B)	(C)	(D)	(E)
Line Devel	opment of Average Balance of Common Equity	Balances @ 12/31/2012	Balances @ 12/31/2011	Average
	1 Proprietary Capital (112.16.c&d) 2 Less Preferred Stock (Ln 54 Below)	1,803,774,755 0	1,760,980,133	1,782,377,444
	3 Less Account 216.1 (112.12.c&d) 4 Less Account 219.1 (112.15.c&d)	(104,879) (28,884,204)	(230,765) (28,221,410)	(167,822) (28,552,807)
	5 Average Balance of Common Equity	1,832,763,838	1,789,432,308	1,811,098,073
<u>Devel</u>	opment of Cost of Long Term Debt Based on Ave	rage Outstanding Bala	<u>nce</u>	
	6 Bonds (112.18.c&d) 7 Less: Reacquired Bonds (112.19.c&d)		-	-
	8 LT Advances from Assoc. Companies (112.20.c&d)		<u> </u>	-
	9 Senior Unsecured Notes (112.21.c&d)10 Less: Fair Value Hedges (See Note on Ln 12 below)	1,572,429,608	1,562,927,505	1,567,678,557
	11 Total Average Debt	1,572,429,608	1,562,927,505	1,567,678,557
	12 NOTE: The balance of fair value hedges on outstanding debt included in the formula's capital structure. (Column	•	cluded from the balar	nce of long term

13 Annual Interest Expense for 2012	
14 Interest on Long Term Debt (256-257.33.i)	90,701,590
Less: Total Hedge Gain/Expense Accumulated from p 256-257, col. (i) of FERC Form	
1 included in Ln 14 and shown in Ln 33 below.	916,010
16 Plus: Allowed Hedge Recovery From Ln 38 below.	916,010
17 Amort of Debt Discount & Expense (117.63.c)	2,372,191
18 Amort of Loss on Reacquired Debt (117.64.c)	1,483,709
19 Less: Amort of Premium on Debt (117.65.c)	-
20 Less: Amort of Gain on Reacquired Debt (117.66.c)	1,712
21 Total Interest Expense (Ln 14 + Ln 17 + Ln 18 - Ln 19 - Ln 20)	94,555,778
22 Average Cost of Debt for 2012 (Ln 21/Ln 11)	6.03%

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.

Amortization Period

HEDGE AMOUNTS BY ISSUANCE (FROM p. 256-257 (i) of the FERC Form 1)	Total Hedge (Gain)/Loss for 2012	Less Excludable Amounts (See NOTE on Line 23)	Net Includable Hedge Amount	Remaining Unamortized Balance	Beginning	Ending
24 Senior Unsecured Notes - Series F	877,840		877,840		November 2004	November 2014
25 Senior Unsecured Notes - Series G	(383,570)		(383,570)	(1,118,746)	December-05	November-15
26 Senior Unsecured Notes - Series H	421,740		421,740	10,174,485	November-06	February-37
27			-			
28			-			
29			-			
30 31			-			
32			_			
02				10,701,690		
33 Total Hedge Amortization	916,010	-	_			
34 Hedge Gain or Loss Prior to Application of Recovery Limit (S	um of Lines 24 to 32)		916,010			
35 Total Average Capital Structure Balance for 2012 (True-UP T			3,378,776,629			
36 Financial Hedge Recovery Limit - Five Basis Points of Total	Capital		0.0005			
37 Limit of Recoverable Amount		<u>-</u>	1,689,388			
38 Recoverable Hedge Amortization (Lesser of Ln 34 or Ln 3	7)		916,010			
elopment of Cost of Preferred Stock						
Preferred Stock			<u>Average</u>			

Devel

elopment of Cost of Preferred Stock						
Preferred Stock					Average	
39 4.125% Series - 100 - Dividend Rate (p. 250-251. 9.a)		4.125%		4.125%		
40 4.125% Series - 100 - Par Value (p. 250-251. 9.c)	\$	100.00	\$	100.00		
41 4.125% Series - 100 - Shares O/S (p.250-251. 9.e)		-		_		
42 4.125% Series - 100 - Monetary Value (Ln 40 * Ln 41)		-		-	-	
43 4.125% Series - 100 - Dividend Amount (Ln 39 * Ln 42)		_		_	_	
44 4.12% Series - 100 - Dividend Rate (p. 250-251 11.a)		4.12%		4.12%		
45 4.12% Series - 100 - Par Value (p. 250-251 11.c)	\$	100.00	\$	100.00		
46 4.12% Series - 100 - Shares O/S (p.250-251 11.e)	•	-	Ť	_		
47 4.12% Series - 100 - Monetary Value (Ln 45 * Ln 46)		_		<u>-</u>	_	
48 4.12% Series - 100 - Dividend Amount (Ln 44 * Ln 47)		_		_	_	
10 1.12/0 conco 100 Bividona / unodin (En 11 En 11)						
49 4.56% Series - 100 - Dividend Rate (p. 250-251. 10a)		4.56%		4.56%		
50 4.56% Series - 100 - Par Value (p. 250-251. 10c)	\$	100.00	\$	100.00		
51 4.56% Series - 100 - Shares O/S (p.250-251 10.e)	•	-	Ψ	-		
52 4.56% Series - 100 - Monetary Value (Ln 50 * Ln 51)		_		_	_	
53 4.56% Series - 100 - Dividend Amount (Ln 49 * Ln 52)		_		_	_	
50 4.56% Cones 100 Dividend Amount (En 45 En 52)						
54 Balance of Preferred Stock (Lns 42, 47, 52)		-		-	-	Year End Total Agrees to FF1 p.112, Ln 3, col (c) & (d)
55 Dividends on Preferred Stock (Lns 43, 48, 53)		-		-	-	
56 Average Cost of Preferred Stock (Ln 55/54)		0.00%		0.00%	0.00%	

AEP East Companies

Cost of Service Formula Rate Using 2012 FF1 Balances Worksheet N - Gains (Losses) on Sales of Plant Held For Future Use INDIANA MICHIGAN POWER COMPANY

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

	(A)	(B)	(C) Function	(D)	(E)	(F)	(G) Functional	(H) Functionalized	(I) FERC
Line	Date	Property Description	(T) or (G) T = Transmission G = General	Basis on	Proceeds	(Gain) / Loss	Allocator	Proceeds (Gain) / Loss	Account
1						-	0.000%	-	
2						-	0.000%	-	
3						-	0.000%	-	
4			N	et (Gain) or L	oss for 2012			<u> </u>	

AEP East Companies

Cost of Service Formula Rate Using 2010 FF1 Balances

Worksheet O - Calculation of Postemployment Benefits Other than Pensions Expenses Allocable to Transmission Service INDIANA MICHIGAN POWER COMPANY

Total AEP East Operating Company PBOP Settlement Amount

48,100,000

Allocation of PBOP Settlement Amount for 2012

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 2012	Actual Expense	Allowable Expense	One Year Functional Expense (Over)/Under
	(A) (Line 14)	(B)=(A)/Total (A)	(C)=(B) * 48100000	(D)	(E)=(A) * (D)	(F)=(C) * (D)	(G)=(E) - (F)
1 APCo	11,359,793	27.78%	13,362,440	7.081%	804,397	946,207	(141,809)
2							
3 I&M	10,586,657	25.89%	12,453,006	4.206%	445,250	523,744	(78,494)
4 KPCo	2,188,039	5.35%	2,573,774	9.694%	212,116	249,511	(37,394)
5 KNGP	277,875	0.68%	326,862	13.137%	36,506	42,941	(6,436)
6 OPCo	16,164,303	39.53%	19,013,950	6.771%	1,094,477	1,287,425	(192,948)
7 WPCo	314,520	0.77%	369,968	7.846%	24,676	29,026	(4,350)
8 Sum of Lines 1 to 7	40,891,187	-	48,100,000		2,617,422	3,078,853	(461,432)

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

	<u>APCo</u>	<u>I&M</u>	<u>KPCo</u>	<u>KNGSPT</u>	<u>OPCo</u>	<u>WPCo</u>	AEP East Total
9 Direct Charged PBOP Expense per Actuarial Report	10,991,074	9,836,923	1,994,927	247,734	13,628,228	282,183	36,981,069
10 Additional PBOP Ledger Entries (from Company Records)	(669,581)	(45,394)	-	-	1,105,077	-	
11 Medicare Subsidy	-	•	-	-	-	-	-
12 Net Company Expense (Ln 9 + Ln 10 + Ln 11)	10,321,493	9,791,529	1,994,927 -	247,734	14,733,305	282,183	37,371,171
13 PBOP Expenses From AEP Service Corporation (from Company Records)	1,038,300	795,128	193,112	30,141	1,430,998	32,337	3,520,016
14 Company PBOP Expense (Ln 12 + Ln 13)	11,359,793	10,586,657	2,188,039	277,875	16,164,303	314,520	40,891,187

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	
	PLANT ACCT.	(1) IURC RATES	ALLOCATION FACTOR (4)	WTD AVG. DEPREC. RATE	(2) MPSC APPROVED RATES	ALLOCATION FACTOR (4)	WTD AVG. DEPREC. RATE	(3) FERC RATES	ALLOCATION FACTOR (4)	WTD AVG. DEPREC. RATE	WTD AVG. DEPREC. RATE	
TRANSMISSION PLANT												
Land Improvements	350.1	1.1600%	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.

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.

⁽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.

KENTUCKY POWER COMPANY

Line No.						T	ransmission Amount
1	REVENUE REQUIREMENT (w/o incentives)	(In 138)	Total	A II .			\$55,400,649
2	REVENUE CREDITS	(Note A) (Worksheet E)	Total 79,378	DA	1.00000	\$	79,378
3	REVENUE REQUIREMENT For All Company Facilities	(In 1 less In 2)				\$	55,321,271
	The Carrying Charge Calculations on lines 6 to 11 belonission Enhancement Charges. The total non-incentive	— — — — — — — — — — — — — — — — — — —					
4	Revenue Requirement for PJM Schedule 12 Facilities (w	//o incentives) (Worksheet J)	-	DA	1.00000	\$	-
5	NET PLANT CARRYING CHARGE w/o intra-AEP charge	es or credits or ROE incentives (Note B)					
6	Annual Rate	((ln 1 - ln 105 - ln 106)/((ln 48 + ln 49 + ln 50 + lr	n 51 + ln 53) x 100))				16.13%
7	Monthly Rate	(ln 6 / 12)					1.34%
8	NET PLANT CARRYING CHARGE ON LINE 6, w/o depr	reciation or ROF incentives (Note B)					
9	Annual Rate	((ln 1 - ln 105 - ln 106 - ln 111 - ln 112) /((ln 48 +	- ln 49 + ln 50 + ln 51 + ln 53) x 100))				13.78%
10	NET PLANT CARRYING CHARGE ON LINE 9, w/o Retu	rn, income taxes or POE incentives (Note R)					
11	Annual Rate	((ln 1 - ln 105 - ln 106 - ln 111 - ln 112 - ln 133 -	In 134) /((In 48 + In 49 + In 50 + In 51 +	In 53) x 100))		3.47%
12	ADDITIONAL REVENUE REQUIREMENT for projects w/	incentive ROE's (Note B) (Worksheet J)					-
13		REVENUE REQUIREMENT FOR SCHED	OULE 1A CHARGES				
14	Total Load Dispatch & Scheduling (Account 561)	Line 85 Below					2,313,221
15	Less: Load Dispatch - Scheduling, System Control and D						1,160,718
16	Less: Load Dispatch - Reliability, Planning & Standards I	Development Services (321.92.b)					245,515
17	Total 561 Internally Developed Costs	(Line 14 - Line 15 - Line 16)					906,988
	•	•					

(5)

(4)

AEP East Companies Transmission Cost of Service Formula Rate Utilizing Historic Cost Data for 2012 and Projected Net Plant at Year-End 2013

KENTUCKY POWER COMPANY

(3)

(2)

(1)

	(.)	(=)	(0)	`	/	(-)
Lina	RATE BASE CALCULATION	Data Sources (See "General Notes")	TO Total	Allo	cator	Total <u>Transmission</u>
Line No.	GROSS PLANT IN SERVICE		NOTE C			
18	Production	(Worksheet A In 1.C)	551,473,235	NA	0.00000	0
19	Less: Production ARO (Enter Negative)	(Worksheet A In 1.0)	-3,614,563	NA NA	0.00000	0
20	Transmission	(Worksheet A In 2.0) (Worksheet A In 3.C & Ln 142)	490,121,490	DA	0.00000	488,475,204
21	Less: Transmission ARO (Enter Negative)	(Worksheet A In 4.C& Ln 143)	0	TP	0.99664	0
22	Plus: Transmission Plant-in-Service Additions (Works	,	17,254,112	DA	1.00000	17,254,112
23	Plus: Additional Trans Plant on Transferred Assets (V	·	0	DA	1.00000	0
24	Distribution	(Worksheet A In 5.C)	651,987,726	NA	0.00000	0
25	Less: Distribution ARO (Enter Negative)	(Worksheet A In 6.C)	0	NA	0.00000	0
26	General Plant	(Worksheet A In 7.C)	35,217,344	W/S	0.09694	3,414,092
27	Less: General Plant ARO (Enter Negative)	(Worksheet A In 8.C)	-81,055	W/S	0.09694	(7,858)
28	Intangible Plant	(Worksheet A In 9.C)	17,734,036	W/S	0.09694	1,719,199
29	TOTAL GROSS PLANT	(sum lns 18 to 28)	1,760,092,325			510,854,749
30	ACCUMULATED DEPRECIATION AND AMORTIZATION	N				
31	Production	(Worksheet A In 12.C)	267,211,806	NA	0.00000	0
32	Less: Production ARO (Enter Negative)	(Worksheet A In 13.C)	-936,402	NA	0.00000	0
33	Transmission	(Worksheet A In 14.C & 28.C)	154,839,705	TP1=	0.99581	154,190,968
34	Less: Transmission ARO (Enter Negative)	(Worksheet A In 15.C)	0	TP1=	0.99581	0
35	Plus: Transmission Plant-in-Service Additions (Works	· · · · · · · · · · · · · · · · · · ·	193,867	DA	1.00000	193,867
36	Plus: Additional Projected Deprec on Transferred Ass	· · · · · · · · · · · · · · · · · · ·	0	DA	1.00000	0
37	Plus: Additional Transmission Depreciation for 2013	•	7,897,690	TP1	0.99581	7,864,601
38	Plus: Additional General & Intangible Depreciation for		3,660,586	W/S	0.09694	354,870
39	Plus: Additional Accum Deprec on Transferred Assets	·	0	DA	1.00000	0
40	Distribution	(Worksheet A In 16.C)	171,225,681	NA	0.00000	0
41	Less: Distribution ARO (Enter Negative)	(Worksheet A In 17.C)	7.062.540	NA W/S	0.00000	774.047
42	General Plant ABO (Enter Negative)	(Worksheet A In 18.C)	7,962,549	W/S W/S	0.09694 0.09694	771,917
43 44	Less: General Plant ARO (Enter Negative) Intangible Plant	(Worksheet A In 19.C) (Worksheet A In 20.C)	-11,119 20,894,341	W/S	0.09694	(1,078) 2,025,570
4 4 45	TOTAL ACCUMULATED DEPRECIATION	(sum lns 31 to 44)	632,938,704	VV/3	0.09094	165,400,715
40	NET DI ANT IN CEDVICE					
46 47	NET PLANT IN SERVICE	(lo 40 + lo 40 - lo 24 - lo 22)	204 502 267			0
47 48	Production Transmission	(In 18 + In 19 - In 31 - In 32) (In 20 + In 21 - In 33 - In 34)	281,583,267 335,281,785			334,284,237
49	Plus: Transmission Plant-in-Service Additions (In 22 -	,	17,060,245			17,060,245
50	Plus: Additional Trans Plant on Transferred Assets (I		17,000,243			17,000,2 4 3
51	Plus: Additional Transmission Depreciation for 2013	•	(7,897,690)			(7,864,601)
52	Plus: Additional General & Intangible Depreciation for	` ,	(3,660,586)			(354,870)
53	Plus: Additional Accum Deprec on Transferred Assets		0			0
54	Distribution	(ln 24 + ln 25 - ln 40 - ln 41)	480,762,045			0
55	General Plant	(ln 26 + ln 27 - ln 42 - ln 43)	27,184,859			2,635,395
56	Intangible Plant	(ln 28 - ln 44)	(3,160,305)			(306,371)
57	TOTAL NET PLANT IN SERVICE	(sum lns 47 to 56)	1,127,153,621			345,454,035
58	DEFERRED TAX ADJUSTMENTS TO RATE BASE	(Note D)				
59	Account No. 281.1 (enter negative)	(Worksheet B, In 2 & In 5.C)	(26,644,638)	NA		0
60	Account No. 282.1 (enter negative)	(Worksheet B, In 7 & In 10.C)	(198,723,117)	DA		(58,756,969)
61	Account No. 283.1 (enter negative)	(Worksheet B, In 12 & In 15.C)	(18,533,602)	DA		(851,337)
62	Account No. 190.1	(Worksheet B, In 17 & In 20.C)	13,719,413	DA		3,137,219
63 64	Account No. 255 (enter negative) TOTAL ADJUSTMENTS	(Worksheet B, In 24 & In 25.C)	(220 191 044)	DA		(FG 471 007)
64	TOTAL ADJUSTMENTS	(sum lns 59 to 63)	(230,181,944)			(56,471,087)
65	PLANT HELD FOR FUTURE USE	(Worksheet A In 29.C & In 30.C)	7,436,551	DA		30,592
66	REGULATORY ASSETS	(Worksheet A In 36. (C))	0	DA		0
67	WORKING CAPITAL	(Note E)				
68	Cash Working Capital	(1/8 * In 88)	691,015			688,694
69	Transmission Materials & Supplies	(Worksheet C, In 2.(D))	29,645	TP	0.99664	29,545
70	A&G Materials & Supplies	(Worksheet C, In 3.(D))	6,628	W/S	0.09694	643
71	Stores Expense	(Worksheet C, In 4.(D))	0	GP(h)	0.28322	0
72	Prepayments (Account 165) - Labor Allocated	(Worksheet C, In 6.G)	27,322,535	W/S	0.09694	2,648,741
73	Prepayments (Account 165) - Gross Plant	(Worksheet C, In 6.F)	634,845	GP(h)	0.28322	179,799
74	Prepayments (Account 165) - Transmission Only	(Worksheet C, In 6.E)	0	DA	1.00000	0
75	Prepayments (Account 165) - Unallocable	(Worksheet C, In 6.D)	(26,387,585)	NA	0.00000	0
76	TOTAL WORKING CAPITAL	(sum lns 68 to 75)	2,297,083			3,547,422
77	IPP CONTRIBUTIONS FOR CONSTRUCTION	(Note F) (Worksheet D, In 7.B)	(260,279)	DA	1.00000	(260,279)
78	RATE BASE (sum Ins 57, 64, 65, 66, 76, 77)		906,445,031			
10	NATE DAGE (Suittins 37, 04, 03, 00, 70, 77)		300,440,001			292,300,682

KENTUCKY POWER COMPANY

(1) (2) (3) (4) (5)

	EXPENSE, TAXES, RETURN & REVENUE REQUIREMENTS CALCULATION	Data Sources (See "General Notes")	TO Total	Allc	ocator_	Total <u>Transmission</u>
Line						
No.	OPERATION & MAINTENANCE EXPENSE	204.001	074 704 040			
79	Production Distribution	321.80.b	371,701,916			
80	Distribution	322.156.b	40,373,125			
81 82	Customer Related Expense Regional Marketing Expenses	322.164,171,178.b 322.131.b	9,222,773 1,194,322			
83	Transmission	321.112.b	12,202,913			
84	TOTAL O&M EXPENSES	(sum lns 79 to 83)	434,695,049			
85	Less: Total Account 561	(Note G) (Worksheet F, In 14.C)	2,313,221			
86	Less: Account 565	(Note H) 321.96.b	4,361,575			
87	Less: State Regulatory Deferrals & Amortizations	(Note I) (Worksheet F, In 4.C)	, , <u>-</u>			
88	Total O&M Allocable to Transmission	(Ins 83 - 85 - 86 - 87)	5,528,117	TP	0.99664	5,509,548
89	Administrative and General	323.197.b (Note J)	19,906,103			
90	Less: Acct. 924, Property Insurance	323.185.b	605,545			
91	Acct. 9260039 PBOP Expense	PBOP Worksheet O Line 9 & 10, (Note K)	1,994,927			
92	Acct. 9260057 PBOP Medicare Subsidy	PBOP Worksheet O Line 11, (Note K)	-			
93	PBOP Expense Billed From AEPSC	PBOP Worksheet O Line 13, (Note K)	193,112			
94	Acct. 928, Reg. Com. Exp.	323.189.b	155,946			
95	Acct. 930.1, Gen. Advert. Exp.	323.191.b	68,468			
96	Acct. 930.2, Misc. Gen. Exp.	323.192.b	290,504			
97	Balance of A & G	(ln 89 - sum ln 90 to ln 96)	16,597,601	W/S	0.09694	1,609,029
98	Plus: Acct. 924, Property Insurance	(In 90)	605,545	GP(h)	0.28322	171,500
99	Acct. 928 - Transmission Specific	Worksheet F In 18.(E) (Note L)	-	TP	0.99664	-
100	Acct 930.1 - Only safety related ads -Direct	Worksheet F In 27.(E) (Note L)	-	TP	0.99664	- 04.070
101	Acct 930.2 - Misc Gen. Exp Trans	Worksheet F In 34.(E) (Note L)	21,276	DA	1.00000	21,276
102	Settlement Approved PBOP Recovery	PBOP Worksheet O, Col. C, Line 4, (Note M)	2,573,774	W/S	0.09694	249,511
103	A & G Subtotal	(sum lns 97 to 102)	19,798,196			2,051,316
104	O & M EXPENSE SUBTOTAL	(ln 88 + ln 103)	25,326,313	D.4	4 00000	7,560,864
105	Plus: TEA Settlement in Account 565	Company Records (Note H)	-	DA	1.00000	-
106	Plus: Transmission Lease Payments To Affiliates in A		-	DA	1.00000	7.500.004
107	TOTAL O & M EXPENSE	(ln 104 + ln 105 + ln 106)	25,326,313			7,560,864
108	DEPRECIATION AND AMORTIZATION EXPENSE	336.2-6.f	20 967 792	NΙΛ	0.00000	
109 110	Production Distribution	336.8.f	20,867,782 22,040,399	NA NA	0.00000	-
111	Transmission	336.7.f	7,897,690	TP1	0.99581	7,864,601
112	Plus: Transmission Plant-in-Service Additions (Works		193,867	DA	1.00000	193,867
113	General	336.10.f	851,375	W/S	0.09694	82,535
114	Intangible	336.1.f	2,809,211	W/S	0.09694	272,335
115	TOTAL DEPRECIATION AND AMORTIZATION	(Lns 109+110+111	54,660,324	*****	0.00001	8,413,338
		+112+113+114)	0 1,000,02 1			3, 1.0,000
116	TAXES OTHER THAN INCOME	(Note N)				
117	Labor Related					
118	Payroll	Worksheet H In 21.(D)	1,700,019	W/S	0.09694	164,806
119	Plant Related	,				·
120	Property	Worksheet H In 21.(C) & In 35.(C)	9,357,117	DA		3,583,173
121	Gross Receipts/Sales & Use	Worksheet H In 21.(F)	186,263	NA	0.00000	-
122	Other	Worksheet H In 21.(E)	916,572	GP(h)	0.28322	259,588
123	TOTAL OTHER TAXES	(sum lns 118 to 122)	12,159,971			4,007,567
124	INCOME TAXES	(Note O)				
125	T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =		38.52%			
126	EIT=(T/(1-T)) * (1-(WCLTD/WACC)) =		38.09%			
127	where WCLTD=(In 162) and WACC = (In 165)					
128	and FIT, SIT & p are as given in Note O.		4.0005			
129	GRCF=1 / (1 - T) = (from In 125)	(FF4 n 444 ln 40 n)	1.6265			
130	Amortized Investment Tax Credit (enter negative)	(FF1 p.114, ln 19.c)	(278,005)			
131	Income Tax Calculation	(In 126 * In 134)	30,406,252			9,805,082
132	ITC adjustment	(ln 129 * ln 130)	(452,162)	NP(h)	0.30010	(135,696)
133	TOTAL INCOME TAXES	(sum lns 131 to 132)	29,954,090		0.00010	9,669,386
		,				
134	RETURN ON RATE BASE (Rate Base * WACC)	(In 78 * In 165)	79,825,288	5 .	4.00000	25,741,204
135	INTEREST ON IPP CONTRIBUTION FOR CONST. (Not		8,290	DA	1.00000	8,290
136	(Gains) / Losses on Sales of Plant Held for Future Use (\		-			-
137	Tax Impact on (Gains) / Losses on Sales of Plant Held for	or Future Use (In 136 * In126)	-			<u> </u>
138	TOTAL REVENUE REQUIREMENT (sum lns 107, 115, 123, 133, 134, 135, 136, 137)		201,934,276			55,400,649

KENTUCKY POWER COMPANY

SUPPORTING CALCULATIONS

ln								
No.	TRANSMISSION PLANT INCLUDED IN PJM TARIFF							
139	Total transmission plant	(In 20)						490,121,490
140	Less transmission plant excluded from PJM Tariff (Note	P)						-
141	Less transmission plant included in OATT Ancillary Serv	ices (Worksheet A, In 23, Col. (C))	(Note Q)					1,646,286
142	Transmission plant included in PJM Tariff	(In 139 - In 140 - In 141)						488,475,204
143	Percent of transmission plant in PJM Tariff	(In 142 / In 139)					TP	0.99664
				Payroll Billed from				
144	WAGES & SALARY ALLOCATOR (W/S)	(Note R)	Direct Payroll	AEP Service Corp.	Total			
145	Production	354.20.b	8,667,563	2,494,771	11,162,334	NA	0.00000	-
146	Transmission	354.21.b	1,152,669		2,570,854	TP	0.99664	2,562,219
147	Regional Market Expenses	354.22.b	0	0	-	NA	0.00000	-
148	Distribution Other (Evaluates ASC)	354.23.b	8,394,535	929,541	9,324,076	NA	0.00000	-
149	Other (Excludes A&G)	354.24,25,26.b	1,686,265	1,686,499	3,372,764	NA	0.00000	2 562 240
150	Total	(sum Ins 145 to 149)	19,901,032	6,528,996	26,430,028			2,562,219
151	Transmission related amount						W/S=	0.09694
151 152	Transmission related amount WEIGHTED AVERAGE COST OF CAPITAL (WACC)						W/S=	0.09694 \$
		(Worksheet L, In. 35, col. (D))					W/S= 	\$ 35,553,541
152	WEIGHTED AVERAGE COST OF CAPITAL (WACC)	(Worksheet L, In. 35, col. (D)) (Worksheet L, In. 40, col. (D))					W/S= 	\$
152 153 154 155	WEIGHTED AVERAGE COST OF CAPITAL (WACC) Long Term Interest Preferred Dividends Development of Common Stock:	(Worksheet L, In. 40, col. (D))					W/S= 	\$ 35,553,541 -
152 153 154 155 156	WEIGHTED AVERAGE COST OF CAPITAL (WACC) Long Term Interest Preferred Dividends Development of Common Stock: Proprietary Capital	(Worksheet L, In. 40, col. (D)) (FF1 p 112, Ln 16.c)					W/S= 	\$
152 153 154 155 156 157	WEIGHTED AVERAGE COST OF CAPITAL (WACC) Long Term Interest Preferred Dividends Development of Common Stock: Proprietary Capital Less: Preferred Stock	(Worksheet L, In. 40, col. (D)) (FF1 p 112, Ln 16.c) (FF1 p 112, Ln 3.c)					W/S=	\$ 35,553,541 -
152 153 154 155 156 157 158	WEIGHTED AVERAGE COST OF CAPITAL (WACC) Long Term Interest Preferred Dividends Development of Common Stock: Proprietary Capital Less: Preferred Stock Less: Account 216.1	(Worksheet L, In. 40, col. (D)) (FF1 p 112, Ln 16.c) (FF1 p 112, Ln 3.c) (FF1 p 112, Ln 12.c)					W/S= 	\$ 35,553,541 - 479,610,035 - -
152 153 154 155 156 157 158 159	WEIGHTED AVERAGE COST OF CAPITAL (WACC) Long Term Interest Preferred Dividends Development of Common Stock: Proprietary Capital Less: Preferred Stock Less: Account 216.1 Less: Account 219	(Worksheet L, In. 40, col. (D)) (FF1 p 112, Ln 16.c) (FF1 p 112, Ln 3.c) (FF1 p 112, Ln 12.c) (FF1 p 112, Ln 15.c)					W/S=	\$ 35,553,541 - 479,610,035 - - (408,880)
152 153 154 155 156 157 158	WEIGHTED AVERAGE COST OF CAPITAL (WACC) Long Term Interest Preferred Dividends Development of Common Stock: Proprietary Capital Less: Preferred Stock Less: Account 216.1	(Worksheet L, In. 40, col. (D)) (FF1 p 112, Ln 16.c) (FF1 p 112, Ln 3.c) (FF1 p 112, Ln 12.c)						\$ 35,553,541 - 479,610,035 - -
152 153 154 155 156 157 158 159	WEIGHTED AVERAGE COST OF CAPITAL (WACC) Long Term Interest Preferred Dividends Development of Common Stock: Proprietary Capital Less: Preferred Stock Less: Account 216.1 Less: Account 219	(Worksheet L, In. 40, col. (D)) (FF1 p 112, Ln 16.c) (FF1 p 112, Ln 3.c) (FF1 p 112, Ln 12.c) (FF1 p 112, Ln 15.c)		\$	%		W/S= Cost (Note S)	\$ 35,553,541 - 479,610,035 - - (408,880)
152 153 154 155 156 157 158 159 160	WEIGHTED AVERAGE COST OF CAPITAL (WACC) Long Term Interest Preferred Dividends Development of Common Stock: Proprietary Capital Less: Preferred Stock Less: Account 216.1 Less: Account 219	(Worksheet L, In. 40, col. (D)) (FF1 p 112, Ln 16.c) (FF1 p 112, Ln 3.c) (FF1 p 112, Ln 12.c) (FF1 p 112, Ln 15.c)		\$ 550,000,000	% 53.40%		Cost	\$ 35,553,541 - 479,610,035 (408,880) 480,018,915
152 153 154 155 156 157 158 159 160	WEIGHTED AVERAGE COST OF CAPITAL (WACC) Long Term Interest Preferred Dividends Development of Common Stock: Proprietary Capital Less: Preferred Stock Less: Account 216.1 Less: Account 219 Common Stock	(Worksheet L, In. 40, col. (D)) (FF1 p 112, Ln 16.c) (FF1 p 112, Ln 3.c) (FF1 p 112, Ln 12.c) (FF1 p 112, Ln 15.c)		\$ 550,000,000			Cost (Note S)	\$ 35,553,541 - 479,610,035 - (408,880) 480,018,915 Weighted
152 153 154 155 156 157 158 159 160	WEIGHTED AVERAGE COST OF CAPITAL (WACC) Long Term Interest Preferred Dividends Development of Common Stock: Proprietary Capital Less: Preferred Stock Less: Account 216.1 Less: Account 219 Common Stock Long Term Debt (Note T) Worksheet L, In 35, col. (B))	(Worksheet L, In. 40, col. (D)) (FF1 p 112, Ln 16.c) (FF1 p 112, Ln 3.c) (FF1 p 112, Ln 12.c) (FF1 p 112, Ln 15.c)		\$ 550,000,000 - 480,018,915 1,030,018,915	53.40%		Cost (Note S)	\$ 35,553,541 - 479,610,035 - (408,880) 480,018,915 Weighted 0.0345

KENTUCKY POWER COMPANY

<u>Notes</u>

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

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

See Worksheet E for details.

- B The annual and monthly net plant carrying charges on page 1 are used to compute the revenue requirement for RTEP sponsored upgrades or those projects receiving approved incentive-ROE's.
- C Transmission Plant balances in this study are projected as of December 31, 2013. Other ratebase amounts are as of December 31, 2012.
- The total-company balances shown for Accounts 281, 282, 283, 190 only reflect ADIT that relates to utility operations. The balance of Account 255 is reduced by prior flow throughs and is completely excluded if the utility chose to utilize amortization of tax credits against FIT expense. An exception to this is pre-1971 ITC balances, which are required to be taken as an offset to rate base. Account 281 is not allocated. In compliance with FERC Rulemaking RM02-7-000, Asset Retirement Obligation deferrals have been removed from ratebase. Transmission ADIT allocations are shown on WS B.

 The company will not include the ADIT portion of deferred hedge gains and losses in rate base.
- E Cash Working Capital assigned to transmission is one-eighth of O&M allocated to transmission, as shown on line 88. It excludes:
 - 1) Load Scheduling & Dispatch Charges in account 561 that are collected in the OATT Ancilliary Services Revenue, as shown on line 85.
 - 2) AEP transmission equalization transfers, as shown on line 86
 - 3) The impact of state regulatory deferrals and amortizations, as shown on line 87
 - 4) All A&G Expenses, as shown on line 103.
- F Consistent with Paragraph 657 of Order 2003-A, the amount on line 77 is equal to the balance of IPP System Upgrade Credits owed to transmission customers that made contributions toward the construction of System upgrades, and includes accrued interest and unreturned balance of contributions. The annual interest expense is included on line 135.
- Removes from the cost of service the Load Scheduling and Dispatch expenses booked to accounts 561.1 through 561.8. Expenses recorded in these accounts, with the exception of 561.4 & 561.8 (lines 15 & 16 above) are recovered in Schedule 1A, OATT ancillary services rates. See Worksheet F, lines 5 through 14, for descriptions and the Form 1 Source of these accounts' balances.
- Removes cost of transmission service provided by others to determine the basis of cash working capital on line 88. To the extent such service is incurred to provide the PJM service at issue, e.g. transmission equalization agreement, such costs are added back on lines 105 and 106 to determine the total O&M collected in the formula. The amounts on lines 105 and 106 are also excluded in the calculation of the FCR percentage calculated on lines 5 through 11.

 The addbacks on lines 105 and 106 of activity recorded in 565 represents inter-company sales or purchases of transmission capacity necessary to meet each AEP company's transmission load relative to their available transmission capacity.

The company records referenced on lines 105 and 106 is the KENTUCKY POWER COMPANY general ledger.

- Removes the impact of state regulatory deferrals or their amortization from O&M expense.
- J General Plant and Administrative & General expenses, other than in accounts 924, 928, and 930, will be functionalized based on the Wages & Salaries "W/S" allocator. The allocation basis for accounts 924, 928 and 930 are separately presented in the formula. A change in the allocation method for an account must be approved via a 205 filing with the FERC.
- K These deductions on lines 91 through 93 are to remove from the cost of service the expenses recorded by the company for Postemployment Benefits Other than Pensions (PBOP). See Note M below for the recoverable PBOP expense.
- Expenses reported for these A&G accounts will be included in the cost of service only to the extent they are directly assignable to transmission service. Worksheet F allocates these expense items. Acct 928 Includes Regulatory Commission expenses itemized in FERC Form-1 at page 351, column H. FERC Assessment Fees and Annual Charges shall not be allocated to transmission. Only safety-related and educational advertising costs in Account 930.1 are included in the TCOS. Account 930.2 includes the expenses incurred by the transmission function for Associated Business Development revenues given as a credit to the TCOS on Worksheet E.
- See note K above. Per the settlement in Docket ER08-1329, recoverable PBOP expense is based on an annual total for the operating companies that is ratioed to them based on the total of actual annual PBOP costs, including charges from the AEP Service Corportation. The calculation of the recoverable amount for each company is shown on Worksheet O, and the process for updating the annual total is documented on Attachment F, Allowable PBOP Expense Formula.
- N Includes only FICA, unemployment, highway, property and other assessments charged in the current year. Gross receipts, sales & use and taxes related to income are excluded.
- The currently effective income tax rate, where FIT is the Federal income tax rate; SIT is the State income tax rate, and p = the percentage of federal income tax deductible for state income taxes. See Worksheet G for the development of the Company's composite SIT. A utility that elected to utilize amortization of tax credits against taxable income, rather than book tax credits to Account No. 255 and reduce rate base, must reduce its income tax expense by the amount of the Amortized Investment Tax Credit (Form 1, 266.8.f) (In 130) multiplied by (1/1-T). If the applicable tax rates are zero enter 0.

Inputs Required:

FIT =

SIT= 5.41% (State Income Tax Rate or Composite SIT. Worksheet G))
p = 0.00% (percent of federal income tax deductible for state purposes)

35.00%

- P Removes plant excluded from the OATT because it does not meet the PJM's definition of Transmission Facilities or is otherwise ineligible to be recovered under the OATT.
- Removes transmission plant (e.g. step-up transformers) included in the development of OATT ancillary service rates and not already removed for reasons indicated in Note P.
- R Includes functional wages & salaries billed by AEP Service Corporation for support of the operating company.
- Long Term Debt cost rate = long-term interest (ln 153) / long term debt (ln 162). Preferred Stock cost rate = preferred dividends (ln 154) / preferred outstanding (ln 163). Common Stock cost rate (ROE) = 11.49%, the rate accepted by FERC in Docket No. ER08-1329. It includes an additional 50 basis points for PJM RTO membership. In the Projected & Historic templates, the interest expense on long-term debt is the sum of a full year's interest expense at the coupon rate for each issuance outstanding as of December 31 of the historic year. The projected expense for variable rate debt will be based on the effective rate at December 31. These conventions ensure that the expense used in the projection will reflect a full year, similar to the actual expense that will appear in the subsequent true-up of the projection, and minimize the impact on the true-up of using a partial year interest expense. The projection will reflect the actual historic-year expense recorded for issuance expenses, discounts and premiums, and gains or losses on reacquired debt. Eligible hedging gains or losses will be limited to five basis points of the projected capital structure. Details and calculations are shown on Worksheet L.
- This note only applies to Indiana Michigan Power Company.
- U This note only applies to the true-up template.

KENTUCKY POWER COMPANY

Line No. 166	REVENUE REQUIREMENT (w/o incentives) REVENUE CREDITS	(In 303) (Note A) (Worksheet E)	Total 79,378	DA	Allocator 1.00000	Tr	ransmission Amount \$54,131,667 79,378			
107	REVENUE CREDITS	(Note A) (Worksheet E)	19,310	DA	1.00000	Φ	79,376			
168	REVENUE REQUIREMENT For All Company Facilities	(In 166 less In 167)				\$	54,052,289			
	MEMO: The Carrying Charge Calculations on lines 171 to 176 below are used in calculating project revenue requirements billed through PJM Schedule 12, Transmission Enhancement Charges. The total non-incentive revenue requirements for these projects shown on line 169 is included in the total on line 168.									
169	Not applicable on this template									
170 171 172	NET PLANT CARRYING CHARGE w/o intra-AEP charges Annual Rate Monthly Rate	or credits or ROE incentives (Note B) ((In 166 - In 270 - In 271)/ In 213 x 100) (In 171 / 12)					16.19% 1.35%			
173 174	NET PLANT CARRYING CHARGE ON LINE 171, w/o dep Annual Rate	reciation or ROE incentives (Note B) ((In 166 - In 270 - In 271 - In 276) / In 213 x 100)					13.84%			
175 176	NET PLANT CARRYING CHARGE ON LINE 174, w/o Retu Annual Rate	urn, income taxes or ROE incentives (Note B) ((In 166 - In 270 - In 271 - In 276 - In 298 - In 299)	/ In 213 x 100)				3.57%			
177	Not applicable on this template									
178		REVENUE REQUIREMENT FOR S	CHEDULE 1A CHARGES							
179 180 181	Total Load Dispatch & Scheduling (Account 561) Less: Load Dispatch - Scheduling, System Control and Dis Less: Load Dispatch - Reliability, Planning & Standards De	·					2,313,221 1,160,718 245,515			
182	Total 561 Internally Developed Costs	(Line 179 - Line 180 - Line 181)					906,988			

KENTUCKY POWER COMPANY

(1) (2) (3)

		Data Sources				Total
Line	RATE BASE CALCULATION	(See "General Notes")	<u>TO Total</u> NOTE C	Alloc	cator_	<u>Transmission</u>
No.	GROSS PLANT IN SERVICE		14012.0			
183	Production	(Worksheet A In 1.C)	551,473,235	NA	0.00000	-
184	Less: Production ARO (Enter Negative)	(Worksheet A In 2.C)	(3,614,563)	NA	0.00000	-
185	Transmission	(Worksheet A In 3.C & Ln 307)	490,121,490	DA TP	0.00664	488,475,204
186 187	Less: Transmission ARO (Enter Negative) Plus: Transmission Plant-in-Service Additions (Works	(Worksheet A In 4.C& Ln 308)	N/A	NA	0.99664 0.00000	N/A
188	Plus: Additional Trans Plant on Transferred Assets (W	•	N/A	NA	0.00000	N/A
189	Distribution	(Worksheet A In 5.C)	651,987,726	NA	0.00000	-
190	Less: Distribution ARO (Enter Negative)	(Worksheet A In 6.C)	-	NA	0.00000	-
191	General Plant	(Worksheet A In 7.C)	35,217,344	W/S	0.09694	3,414,092
192	Less: General Plant ARO (Enter Negative)	(Worksheet A In 8.C)	(81,055)	W/S	0.09694	(7,858)
193	Intangible Plant	(Worksheet A In 9.C)	17,734,036	W/S	0.09694	1,719,199
194	TOTAL GROSS PLANT	(sum Ins 183 to 193)	1,742,838,213	GP(h)= GTD=	0.283217 0.42770	493,600,637
195	ACCUMULATED DEPRECIATION AND AMORTIZATIO					
196	Production	(Worksheet A In 12.C)	267,211,806	NA	0.00000	-
197	Less: Production ARO (Enter Negative)	(Worksheet A In 13.C)	(936,402)	NA TP1=	0.00000	454400000
198 199	Transmission Less: Transmission ARO (Enter Negative)	(Worksheet A In 14.C & 28.C) (Worksheet A In 15.C)	154,839,705	TP1=	0.99581 0.99581	154,190,968
200	Plus: Transmission Plant-in-Service Additions (Works	,	N/A	DA	1.00000	N/A
201	Plus: Additional Projected Deprec on Transferred Ass	·	N/A	DA	1.00000	N/A
202	Plus: Additional Transmission Depreciation for 2013		N/A	TP1	0.99581	N/A
203	Plus: Additional General & Intangible Depreciation for	` '	N/A	W/S	0.09694	N/A
204	Plus: Additional Accum Deprec on Transferred Assets	s (Worksheet I)	N/A	DA	1.00000	N/A
205	Distribution	(Worksheet A In 16.C)	171,225,681	NA	0.00000	-
206	Less: Distribution ARO (Enter Negative)	(Worksheet A In 17.C)	- 	NA	0.00000	-
207	General Plant	(Worksheet A In 18.C)	7,962,549	W/S	0.09694	771,917
208 209	Less: General Plant ARO (Enter Negative) Intangible Plant	(Worksheet A In 19.C) (Worksheet A In 20.C)	(11,119) 20,894,341	W/S W/S	0.09694 0.09694	(1,078) 2,025,570
209	TOTAL ACCUMULATED DEPRECIATION	(sum Ins 196 to 209)	621,186,561	VV/3	0.09094	156,987,377
		(30111113 130 to 203)	021,100,301			130,907,377
211	NET PLANT IN SERVICE	(la 400 : la 404 la 400 la 407)	204 502 207			
212 213	Production Transmission	(In 183 + In 184 - In 196 - In 197) (In 185 + In 186 - In 198 - In 199)	281,583,267 335,281,785			- 334,284,237
213	Plus: Transmission Plant-in-Service Additions (In 187	,	N/A			N/A
215	Plus: Additional Trans Plant on Transferred Assets (III	,	N/A			N/A
216	Plus: Additional Transmission Depreciation for 2013	•	N/A			N/A
217	Plus: Additional General & Intangible Depreciation for	·	N/A			N/A
218	Plus: Additional Accum Deprec on Transferred Assets	s (Worksheet I) (-In 204)	N/A			N/A
219	Distribution	(In 189 + In 190 - In 205 - In 206)	480,762,045			-
220	General Plant	(ln 191 + ln 192 - ln 207 - ln 208)	27,184,859			2,635,395
221	Intangible Plant	(ln 193 - ln 209)	(3,160,305)	ND/b_	0.200405	(306,371)
222	TOTAL NET PLANT IN SERVICE	(sum Ins 212 to 221)	1,121,651,652	NP(h)=	0.300105	336,613,260
223	DEFERRED TAX ADJUSTMENTS TO RATE BASE	(Note D)				
224	Account No. 281.1 (enter negative)	(Worksheet B, In 2 & In 5.C)	(26,644,638)	NA		-
225	Account No. 282.1 (enter negative)	(Worksheet B, In 7 & In 10.C)	(198,723,117)	DA		(58,756,969)
226	Account No. 283.1 (enter negative)	(Worksheet B, In 12 & In 15.C)	(18,533,602)	DA		(851,337)
227	Account No. 190.1	(Worksheet B, In 17 & In 20.C)	13,719,413	DA		3,137,219
228 229	Account No. 255 (enter negative) TOTAL ADJUSTMENTS	(Worksheet B, In 24 & In 25.C) (sum Ins 224 to 228)	(230,181,944)	DA		(56,471,087)
		,	·			
230	PLANT HELD FOR FUTURE USE	(Worksheet A In 29.C & In 30.C)	7,436,551	DA		30,592
231	REGULATORY ASSETS	(Worksheet A In 36. (C))	-	DA		-
232	WORKING CAPITAL	(Note E)				
233	Cash Working Capital	(1/8 * In 253)	691,015			688,694
234	Transmission Materials & Supplies	(Worksheet C, In 2.(D))	29,645	TP	0.99664	29,545
235	A&G Materials & Supplies	(Worksheet C, In 3.(D))	6,628	W/S	0.09694	643
236 237	Stores Expense Prepayments (Account 165) - Labor Allocated	(Worksheet C, In 4.(D)) (Worksheet C, In 6.G)	- 27,322,535	GP(h) W/S	0.28322 0.09694	- 2,648,741
237 238	Prepayments (Account 165) - Labor Allocated Prepayments (Account 165) - Gross Plant	(Worksheet C, In 6.F)	27,322,535 634,845	GP(h)	0.09694	2,648,741 179,799
239	Prepayments (Account 165) - Transmission Only	(Worksheet C, In 6.E)	-	DA	1.00000	-
240	Prepayments (Account 165) - Unallocable	(Worksheet C, In 6.D)	(26,387,585)	NA	0.00000	
241	TOTAL WORKING CAPITAL	(sum Ins 233 to 240)	2,297,083			3,547,422
242	IPP CONTRIBUTIONS FOR CONSTRUCTION	(Note F) (Worksheet D, In 7.B)	(260,279)	DA	1.00000	(260,279)
243	RATE BASE (sum Ins 222, 229, 230, 231, 241, 242)		900,943,062			283,459,908
∠ ⊣∪						200,400,000

KENTUCKY POWER COMPANY

(1) (2) (3)

Policy P	Line	EXPENSE, TAXES, RETURN & REVENUE REQUIREMENTS CALCULATION	Data Sources (See "General Notes")	TO Total	Alloc	eator_	Total <u>Transmission</u>
Add Production		OPERATION & MAINTENANCE EXPENSE					
Concessed instanced in-answers 379 X DS 161 44 71 178			321.80.b	371,701,916			
Page							
1000 1000		•	, ,				
Section Control Column Control Column Co							
Less Total Account 56 (Note of Workslater) F, in 14.0 4.00 5.21 2.21							
Less Regulatory Defends & Amusilization Post Power sheet F, in 4.0			,				
1000 GAM Allecable to Insernation 1010 GAM Allecable to Insert 1010 GAM	251	Less: Account 565		4,361,575			
Activitation and Concret Activitation Services Activitation Services Activitation Services Activitation Services Activitation Services Activitation Services PEDP Wishelms Co Line 3, Nines () PEDP Expenses PEDP Wishelms Co Line 13, Nines () PEDP Expenses PEDP Wishelms Co Line 13, Nines () PEDP Wishelms Co Line 13, Nines () PEDP Wishelms Co Line 13, Nines () Activitation Services Activitation Serv				<u> </u>			
Less: Act. 362 Papersylmonamore 32.186.5 605.45 190.1427	253	Total O&M Allocable to Transmission	(Ins 248 - 250 - 251 - 252)	5,528,117	TP	0.99664	5,509,548
Less: Act. 2024 Properly Insurance 921, 486.5 905, 485.	254	Administrative and General	323.197.b (Note J)	19,906,103			
Act. 9500.67 PROP Nethiers Standing PEOP Winthers Clam's 1, Note (1) PEOP Winthers Clam's 1, Note (1) PEOP Propries Stands Clam's 1, Note (1) PEOP Winthers Clam's 1,		Less: Acct. 924, Property Insurance	,				
PBOP Popera Billed From AEIPC PBOP (Worksheet O Line 13, Note No. 183,112 185,000 18		·		1,994,927			
Acc. 928 Feeg Corn. Exp. 323 198.5 1859.46 88.48 88.				-			
Acct. S011. Gen. Acct. S011. Gen. Acct. S011. Gen. Acct. S012. Gen. Exp. 323.191.5 200.001.5 200.0		·		·			
261 Act. 9012, Miles, Ger. Exp. 223 1925 16,007 on 261 17,000							
Balance of A & C (1,000 1,000		·					
Plast Act 924, Properly Insurance (in 25)		· • • • • • • • • • • • • • • • • • • •			W/S	0.09694	1,609,029
Act 20.1 - Only surfay registed ads - Clased Pia Z (E) (Nate I) 21,276 DA 0.00004 21,276 22,276,2774 W/S 0.09934 21,276,27774 W/S 0.09934 21,276,27774 W/S 0.09934 21,276,277774 W/S 0.09934 W/S 0	263	Plus: Acct. 924, Property Insurance	,	605,545	GP(h)	0.28322	171,500
Accidence Part Pa		• • • • • • • • • • • • • • • • • • •	` , ` ,	-			-
Settlement Approved PSCP Recovery PSCP Worksheet O. Col. C., Line 4, (Note M) 2.573,774 W/S 0.0864 248,511			` , ` ,	-			-
2,051,315 2,05			· · · · · · · · · · · · · · · · · · ·				
268 O. & M. EXPENSE SUBTOTAL (In. 263 + In. 288) 25.326.313 DA 1.00000 - 2.00000 - 2.000000 - 2.000000 - 2.0000000 - 2.00000000000000000000000000000000000					VV/3	0.09094	
Plus TEA Settlement in Account 565	200	A & O Subiolai	(30111 1113 202 10 201)	19,790,190			2,031,310
Plus TEA Settlement in Account 565	269	O & M EXPENSE SUBTOTAL	(In 253 + In 268)	25,326,313			7,560,864
TOTAL O. & MEXPENSE	270	Plus: TEA Settlement in Account 565	Company Records (Note H)		DA	1.00000	-
DEPRECIATION AND AMORTIZATION EXPENSE 20,007,782 NA		•			DA	1.00000	
Production 336.2-6.1 20,867.782 NA 0,00000	272	TOTAL O & M EXPENSE	(In 269 + In 270 + In 271)	25,326,313			7,560,864
Production 336.2-6.1 20,867.782 NA 0,00000	273	DEPRECIATION AND AMORTIZATION EXPENSE					
Distribution 33.6 at 22.040,389 NA 0.00000 7,887,680 TP1 0.95581 7,884,601 7,887,680 7,887,6			336.2-6.f	20.867.782	NA	0.0000	-
Piets Transmission Plant-in-Service Additions (Worksheet I)							-
Companies Comp	276	Transmission	336.7.f	The state of the s	TP1	0.99581	
Paragraphie Sa6.1.1		•	•				
TOTAL DEPRECIATION AND AMORTIZATION Line 274-275+ 276-2774-278-279 TAXES OTHER THAN INCOME (Note N) Plant Related Payroll Worksheet H in 21.(D) 1.700.019 W/S 0.09894 164.806 Plant Related Property Worksheet H in 21.(C) & in 35.(C) 9.357.117 DA 0.00000 2.50 Plant Related Worksheet H in 21.(F) 186.263 NA 0.00000 2.50 Other Other Other (Note N) 0.28322 259.388 Poyroll (Note N) 1.700.019 W/S 0.09894 164.806 Plant Related Worksheet H in 21.(C) & in 35.(C) 9.357.117 DA 0.00000 2.50 Other Other (Note N) 0.00000 0.50 Other (Note N) 0.00000 0.50 Other (Note N) 0.000000 0.00000 0.000000 0.000000 0.000000 0.000000 0.000000 0.000000 0.000000 0.000000 0.000000 0.000000 0.00000000							
TAXES OTHER THAN INCOME		•			VV/3	0.09094	
TAXES OTHER THAN INCOME (Note N)	200	TOTAL DELINEONATION AND AMORTIZATION	· ·	34,400,437			0,213,471
Payroll Plant Related Plant Related Property Worksheet H In 21,(C) & In 35,(C) 9,357,117 DA 3,583,173 286	281	TAXES OTHER THAN INCOME	,				
Plant Related Property		Labor Related					
Property Worksheet H In 21,(E) & In 35,(C) 9,357,117 DA 0,00000 3,353,173 286 Gross Receipts/Sales & Use Worksheet H In 21,(E) 186,263 NA 0,00000 0,2 2,59,588 7,00000 12,159,871 1		· · · · · · · · · · · · · · · · · · ·	Worksheet H In 21.(D)	1,700,019	W/S	0.09694	164,806
286 Gross Receipts/Sales & Use Worksheet H In 21 (F) 916,572 GP(h) 0.28322 2.59,588 287 TOTAL OTHER TAXES (sum Ins 285 to 287) 12,159,971 12,159,971 2,159,971			Workshoot II In 24 (C) 9 In 25 (C)	0.257.447	DΛ		2 502 172
Other Other Worksheet H In 21,(E) 916,672 GP(h) 0.28322 259,588		, ,	` , , , , , , , , , , , , , , , , , , ,	• •		0.0000	3,303,173
TOTAL OTHER TAXES (sum ins 283 to 287) 12,159,971 4,007,567		·	` '	·			259,588
290 T=1-{[(1-SIT)*(1-FIT)*/1-SIT*FIT*p)}= 38.52% 291 EIT=(T(1-T))*(1-FIT)*/(1-SIT*FIT*p)}= 38.52% 292 where WCLTD=(In 327) and WACC = (In 330) 293 and FIT, SIT & p are as given in Note O. 294 GRCF=1/(1-T) = (from In 290) 295 Amortized Investment Tax Credit (enter negative) (FF1 p.114, In 19.c) (278.005) 296 Income Tax Calculation (In 291* In 299) 30,221,691 297 ITC adjustment (In 294* In 295) (452,162) NP(h) 0.30010 (135,696) 298 TOTAL INCOME TAXES (sum Ins 296 to 297) 29,769,529 299 RETURN ON RATE BASE (Rate Base*WACC) (In 243* In 330) 79,340,762 200 INTEREST ON IPP CONTRIBUTION FOR CONST. (Note F) (Worksheet D, In 2.(B)) 8,290 201 (Gains) / Losses on Sales of Plant Held for Future Use (Worksheet N, In 4, Cols. ((F) & (H))) - 1 202 Tax Impact on Net Loss / (Gain) on Sales of Plant Held for Future Use (In 301* In291) 203 TOTAL REVENUE REQUIREMENT 201.0000 204 S8.290 205 S4,131,667		TOTAL OTHER TAXES	` ,	·	()		
290 T=1-{[(1-SIT)*(1-FIT)*/1-SIT*FIT*p)}= 38.52% 291 EIT=(T(1-T))*(1-FIT)*/(1-SIT*FIT*p)}= 38.52% 292 where WCLTD=(In 327) and WACC = (In 330) 293 and FIT, SIT & p are as given in Note O. 294 GRCF=1/(1-T) = (from In 290) 295 Amortized Investment Tax Credit (enter negative) (FF1 p.114, In 19.c) (278.005) 296 Income Tax Calculation (In 291* In 299) 30,221,691 297 ITC adjustment (In 294* In 295) (452,162) NP(h) 0.30010 (135,696) 298 TOTAL INCOME TAXES (sum Ins 296 to 297) 29,769,529 299 RETURN ON RATE BASE (Rate Base*WACC) (In 243* In 330) 79,340,762 200 INTEREST ON IPP CONTRIBUTION FOR CONST. (Note F) (Worksheet D, In 2.(B)) 8,290 201 (Gains) / Losses on Sales of Plant Held for Future Use (Worksheet N, In 4, Cols. ((F) & (H))) - 1 202 Tax Impact on Net Loss / (Gain) on Sales of Plant Held for Future Use (In 301* In291) 203 TOTAL REVENUE REQUIREMENT 201.0000 204 S8.290 205 S4,131,667							
EIT=(T/(1-T)) * (1 (WCLTD/WACC)) = 38.09%			(Note O)	00.500/			
292 where WCLTD=(in 327) and WACC = (in 330) 293 and FIT, SIT & p are as given in Note O. 294 GRCF=1 / (1 - T) = (from in 290) 295 Amortized Investment Tax Credit (enter negative) (FF1 p.114, ln 19.c) 296 Income Tax Calculation (ln 291 * ln 299) 30,221,691 297 ITC adjustment (ln 294 * ln 295) (452,162) 298 TOTAL INCOME TAXES (sum lns 296 to 297) 29,769,529 299 RETURN ON RATE BASE (Rate Base*WACC) (ln 243 * ln 330) 79,340,762 24,962,649 300 INTEREST ON IPP CONTRIBUTION FOR CONST. (Note F) (Worksheet D, ln 2.(B)) 8,290 DA 1.00000 8,290 301 (Gains) / Losses on Sales of Plant Held for Future Use (Worksheet N, in 4, Cols. ((F) & (H))) - - - 302 Tax Impact on Net Loss / (Gain) on Sales of Plant Held for Future Use (in 301 * ln291) - - - 303 TOTAL REVENUE REQUIREMENT 201,071,322 54,131,667		7-1					
293 and FIT, SIT & p are as given in Note O. 294 GRCF=1 / (1 - T) = (from lin 290) 295 Amortized Investment Tax Credit (enter negative) 296 Income Tax Calculation 297 ITC adjustment 298 TOTAL INCOME TAXES 299 RETURN ON RATE BASE (Rate Base*WACC) 299 RETURN ON RATE BASE (Rate Base*WACC) 290 INTEREST ON IPP CONTRIBUTION FOR CONST. (Note F) (Worksheet D, ln 2.(B)) 290 INTEREST ON IPP CONTRIBUTION FOR CONST. (Note F) (Worksheet N, ln 4, Cols. ((F) & (H))) 290 Tax Impact on Net Loss / (Gain) on Sales of Plant Held for Future Use (In 301 * In291) 290 INTEREST ON IPP CONTRIBUTION FOR CONST. (Note F) (The Action of Plant Held for Future Use (In 301 * In291) 290 Total Revenue Requirement 291 Total Revenue Requirement 292 Total Revenue Requirement 293 Total Revenue Requirement 294,962,649 295 Total Revenue Requirement 295 Total Revenue Requirement 296 Total Revenue Requirement 297 Total Revenue Requirement 298 Total Revenue Reguirement 299 Total Revenue Reguirem				36.09%			
Company Comp		, , , , , , , , , , , , , , , , , , , ,					
295 Amortized Investment Tax Credit (enter negative) (FF1 p.114, ln 19.c) (278,005) 296 Income Tax Calculation (ln 291 * ln 299) 30,221,691 9,508,523 297 ITC adjustment (ln 294 * ln 295) (452,162) NP(h) 0.30010 (135,696) 298 TOTAL INCOME TAXES (sum Ins 296 to 297) 29,769,529 NP(h) 0.30010 (135,696) 299 RETURN ON RATE BASE (Rate Base*WACC) (ln 243 * ln 330) 79,340,762 24,962,649 300 INTEREST ON IPP CONTRIBUTION FOR CONST. (Note F) (Worksheet D, ln 2.(B)) 8,290 DA 1.00000 8,290 301 (Gains) / Losses on Sales of Plant Held for Future Use (Worksheet N, ln 4, Cols. ((F) & (H))) - - - 302 Tax Impact on Net Loss / (Gain) on Sales of Plant Held for Future Use (ln 301 * ln291) - 54,131,667				1.6265			
Total Income	295		(FF1 p.114, ln 19.c)	(278,005)			
Total Income	000	In come Tay Calaulation	(la 004 * la 000)	20.204.224			0.500.500
298 TOTAL INCOME TAXES (sum Ins 296 to 297) 29,769,529 9,372,827 299 RETURN ON RATE BASE (Rate Base*WACC) (ln 243 * ln 330) 79,340,762 24,962,649 300 INTEREST ON IPP CONTRIBUTION FOR CONST. (Note F) (Worksheet D, ln 2.(B)) 8,290 DA 1.00000 8,290 301 (Gains) / Losses on Sales of Plant Held for Future Use (Worksheet N, ln 4, Cols. ((F) & (H))) - - - - 302 Tax Impact on Net Loss / (Gain) on Sales of Plant Held for Future Use (ln 301 * ln291) - - - - 303 TOTAL REVENUE REQUIREMENT 201,071,322 54,131,667			,	• •	ND/b)	0.20010	· · ·
299 RETURN ON RATE BASE (Rate Base*WACC) (In 243 * In 330) 79,340,762 24,962,649 300 INTEREST ON IPP CONTRIBUTION FOR CONST. (Note F) (Worksheet D, In 2.(B)) 8,290 DA 1.00000 8,290 301 (Gains) / Losses on Sales of Plant Held for Future Use (Worksheet N, In 4, Cols. ((F) & (H))) - - - 302 Tax Impact on Net Loss / (Gain) on Sales of Plant Held for Future Use (In 301 * In291) - - 54,131,667 303 TOTAL REVENUE REQUIREMENT 201,071,322 54,131,667		•	,		INF(II)	0.30010	•
300 INTEREST ON IPP CONTRIBUTION FOR CONST. (Note F) (Worksheet D, In 2.(B)) 8,290 DA 1.00000 8,290 301 (Gains) / Losses on Sales of Plant Held for Future Use (Worksheet N, In 4, Cols. ((F) & (H))) - - - 302 Tax Impact on Net Loss / (Gain) on Sales of Plant Held for Future Use (In 301 * In291) - - - 303 TOTAL REVENUE REQUIREMENT 201,071,322 54,131,667	200	TO THE INCOME THAT	(54111116 255 16 257)	20,100,020			0,012,021
301 (Gains) / Losses on Sales of Plant Held for Future Use (Worksheet N, In 4, Cols. ((F) & (H)) Tax Impact on Net Loss / (Gain) on Sales of Plant Held for Future Use (In 301 * In291) TOTAL REVENUE REQUIREMENT - 201,071,322 54,131,667	299	RETURN ON RATE BASE (Rate Base*WACC)	(In 243 * In 330)	79,340,762			24,962,649
302 Tax Impact on Net Loss / (Gain) on Sales of Plant Held for Future Use (In 301 * In291) - 303 TOTAL REVENUE REQUIREMENT - 201,071,322 54,131,667	300	INTEREST ON IPP CONTRIBUTION FOR CONST. (Note I	F) (Worksheet D, In 2.(B))	8,290	DA	1.00000	8,290
303 TOTAL REVENUE REQUIREMENT <u>201,071,322</u> <u>54,131,667</u>	301	(Gains) / Losses on Sales of Plant Held for Future Use (Wo	orksheet N, In 4, Cols. ((F) & (H))	-			-
	302	Tax Impact on Net Loss / (Gain) on Sales of Plant Held for	Future Use (In 301 * In291)	-			-
	200	TOTAL DEVENUE DECLUDEMENT		004.074.000			F4.404.007
	303			201,071,322			54,131,667

KENTUCKY POWER COMPANY

SUPPORTING CALCULATIONS

ln								
No.	TRANSMISSION PLANT INCLUDED IN PJM TARIFF							
304	Total transmission plant	(In 185)						490,121,490
305	Less transmission plant excluded from PJM Tariff (Note	,						
306	Less transmission plant included in OATT Ancillary Servi	ces (Worksheet A, In 23, Col. (C)) (Note Q)					1,646,286
307	Transmission plant included in PJM Tariff	(In 304 - In 305 - In 306)					_	488,475,204
308	Percent of transmission plant in PJM Tariff	(In 307 / In 304)					TP=	0.99664
				Payroll Billed from				
309	WAGES & SALARY ALLOCATOR (W/S)	(Note R)	Direct Payroll	AEP Service Corp.	Total			
310	Production	354.20.b	8,667,563	2,494,771	11,162,334	NA	0.00000	-
311	Transmission	354.21.b	1,152,669	1,418,185	2,570,854	TP	0.99664	2,562,219
312	Regional Market Expenses	354.22.b	0	0	-	NA	0.00000	-
313	Distribution	354.23.b	8,394,535	929,541	9,324,076	NA	0.00000	-
314	Other (Excludes A&G)	354.24,25,26.b	1,686,265	1,686,499	3,372,764	NA	0.00000	-
315	Total	(sum Ins 310 to 314)	19,901,032	6,528,996	26,430,028			2,562,219
316	Transmission related amount						W/S=	0.09694
317	WEIGHTED AVERAGE COST OF CAPITAL (WACC)							\$
318	Long Term Interest	(Worksheet L, In. 35, col. (D))						35,553,541
319	Preferred Dividends	(Worksheet L, In. 40, col. (D))						-
320	Development of Common Stock:							
321	Proprietary Capital	(FF1 p 112, Ln 16.c)						479,610,035
322	Less: Preferred Stock	(FF1 p 112, Ln 3.c)						-
323	Less: Account 216.1	(FF1 p 112, Ln 12 .c)						-
324	Less: Account 219	(FF1 p 112, Ln 15.c)						(408,880)
325	Common Stock	(ln 321 - ln 322 - ln 323 - ln 32	24)				Coot	480,018,915
326				\$	%		Cost (Note S)	Weighted
327	Long Term Debt (Note T) Worksheet L, In 35, col. (B))		•	550,000,000	53.40%		0.0646	0.0345
328	Preferred Stock (In 322)			· · ·	0.00%		-	0.0000
329	Common Stock (În 325)			480,018,915	46.60%		11.49%	0.0535
330	Total (Sum Ins 327 to 329)		•	1,030,018,915			WACC=	0.0881

KENTUCKY POWER COMPANY

<u>Letter</u> <u>Notes</u>

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

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

See Worksheet E for details.

- B The annual and monthly net plant carrying charges on page 1 are used to compute the revenue requirement for RTEP sponsored upgrades or those projects receiving approved incentive-ROE's.
- C Transmission Plant balances in this study are projected as of December 31, 2012.
- The total-company balances shown for Accounts 281, 282, 283, 190 only reflect ADIT that relates to utility operations. The balance of Account 255 is reduced by prior flow throughs and is completely excluded if the utility chose to utilize amortization of tax credits against FIT expense. An exception to this is pre-1971 ITC balances, which are required to be taken as an offset to rate base. Account 281 is not allocated. In compliance with FERC Rulemaking RM02-7-000, Asset Retirement Obligation deferrals have been removed from ratebase. Transmission ADIT allocations are shown on WS B.

 The company will not include the ADIT portion of deferred hedge gains and losses in rate base.
 - Cash Working Capital assigned to transmission is one-eighth of O&M allocated to transmission, as shown on line 253. It excludes:
 - 1) Load Scheduling & Dispatch Charges in account 561 that are collected in the OATT Ancilliary Services Revenue, as shown on line 250.
 - 2) AEP transmission equalization transfers, as shown on line 251
 - 3) The impact of state regulatory deferrals and amortizations, as shown on line 252
 - 4) All A&G Expenses, as shown on line 268.
- F Consistent with Paragraph 657 of Order 2003-A, the amount on line 242 is equal to the balance of IPP System Upgrade Credits owed to transmission customers that made contributions toward the construction of System upgrades, and includes accrued interest and unreturned balance of contributions. The annual interest expense is included on line 300.
- Removes from the cost of service the Load Scheduling and Dispatch expenses booked to accounts 561.1 through 561.8. Expenses recorded in these accounts, with the exception of 561.4 & 561.8 (lines 180 & 181 above) are recovered in Schedule 1A, OATT ancillary services rates. See Worksheet F, lines 5 through 14, for descriptions and the Form 1 Source of these accounts' balances.
- H Removes cost of transmission service provided by others to determine the basis of cash working capital on line 253. To the extent such service is incurred to provide the PJM service at issue, e.g. transmission equalization agreement, such costs are added back on lines 270 and 271 to determine the total O&M collected in the formula. The amounts on lines 270 and 271 are also excluded in the calculation of the FCR percentage calculated on lines 170 through 176.
 - The addbacks on lines 270 and 271 of activity recorded in 565 represents inter-company sales or purchases of transmission capacity necessary to meet each AEP company's transmission load relative to their available transmission capacity.

The company records referenced on lines 270 and 271 is the KENTUCKY POWER COMPANY general ledger.

- I Removes the impact of state regulatory deferrals or their amortization from O&M expense.
 - General Plant and Administrative & General expenses, other than in accounts 924, 928, and 930, will be functionalized based on the Wages & Salaries "W/S" allocator. The allocation basis for accounts 924, 928 and 930 are separately presented in the formula. A change in the allocation method for an account must be approved via a 205 filing with the FERC.
- K These deductions on lines 256 through 258 are to remove from the cost of service the expenses recorded by the company for Postemployment Benefits Other than Pensions (PBOP). See Note M below for the recoverable PBOP expense.
- Expenses reported for these A&G accounts will be included in the cost of service only to the extent they are directly assignable to transmission service. Worksheet F allocates these expense items. Acct 928 Includes Regulatory Commission expenses itemized in FERC Form-1 at page 351, column H. FERC Assessment Fees and Annual Charges shall not be allocated to transmission. Only safety-related and educational advertising costs in Account 930.1 are included in the TCOS. Account 930.2 includes the expenses incurred by the transmission function for Associated Business Development revenues given as a credit to the TCOS on Worksheet E.
- M See note K above. Per the settlement in Docket ER08-1329, recoverable PBOP expense is based on an annual total for the operating companies that is ratioed to them based on the total of actual annual PBOP costs, including charges from the AEP Service Corportation. The calculation of the recoverable amount for each company is shown on Worksheet O, and the process for updating the annual total is documented on Attachment F, Allowable PBOP Expense Formula.
- N Includes only FICA, unemployment, highway, property and other assessments charged in the current year. Gross receipts, sales & use and taxes related to income are excluded.
- The currently effective income tax rate, where FIT is the Federal income tax rate; SIT is the State income tax rate, and p = the percentage of federal income tax deductible for state income taxes. See Worksheet G for the development of the Company's composite SIT.

 A utility that elected to utilize amortization of tax credits against taxable income, rather than book tax credits to Account No. 255 and reduce rate base, must reduce its income tax expense by the amount of the Amortized Investment Tax Credit (Form 1, 266.8.f)

 (In 295) multiplied by (1/1-T). If the applicable tax rates are zero enter 0.

Inputs Required:

FIT = 35.00%

SIT= 5.41% (State Income Tax Rate or Composite SIT. Worksheet G))

p = 0.00% (percent of federal income tax deductible for state purposes)

- P Removes plant excluded from the OATT because it does not meet the PJM's definition of Transmission Facilities or is otherwise ineligible to be recovered under the OATT.
- Q Removes transmission plant (e.g. step-up transformers) included in the development of OATT ancillary service rates and not already removed for reasons indicated in Note P.
- R Includes functional wages & salaries billed by AEP Service Corporation for support of the operating company.
- S Long Term Debt cost rate = long-term interest (ln 318) / long term debt (ln 327). Preferred Stock cost rate = preferred dividends (ln 319) / preferred outstanding (ln 328). Common Stock cost rate (ROE) = 11.49%, the rate accepted by FERC in Docket No. ER08-1329. It includes an additional 50 basis points for remaining a member of the PJM RTO.

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

- T This note only applies to Indiana Michigan Power Company.
- U This note only applies to the true-up template.

KENTUCKY POWER COMPANY

Line No.						Tı	ransmission Amount
1	REVENUE REQUIREMENT (w/o incentives)	(In 138)	Tatal		A lla cata :		\$52,145,724
2	REVENUE CREDITS	(Note A) (Worksheet E)	Total 79,378	DA	Allocator 1.00000	\$	79,378
3	REVENUE REQUIREMENT For All Company Facilities	(In 1 less In 2)				\$	52,066,346
	The Carrying Charge Calculations on lines 6 to 11 belo smission Enhancement Charges. The total non-incenti		_				
4	Revenue Requirement for PJM Schedule 12 Facilities (w	//o incentives) (Worksheet K)	-	DA	1.00000	\$	-
5 6 7	NET PLANT CARRYING CHARGE w/o intra-AEP charge Annual Rate Monthly Rate	es or credits or ROE incentives (Note B) ((In 1 - In 105 - In 106)/ In 48 x 100) (In 6 / 12)					16.37% 1.36%
8 9	NET PLANT CARRYING CHARGE ON LINE 6, w/o depr Annual Rate	reciation or ROE incentives (Note B) ((In 1 - In 105 - In 106 - In 111) / In 48 x 100)					13.90%
10 11	NET PLANT CARRYING CHARGE ON LINE 9, w/o Return Annual Rate	rn, income taxes or ROE incentives (Note B) ((In 1 - In 105 - In 106 - In 111 - In 133 - In 134)	/ In 48 x 100)				3.74%
12	ADDITIONAL REVENUE REQUIREMENT for projects w/	incentive ROE's (Note B) (Worksheet K)					-
13		REVENUE REQUIREMENT FOR SCHE	DULE 1A CHARGES				
14 15 16	Total Load Dispatch & Scheduling (Account 561) Less: Load Dispatch - Scheduling, System Control and Dispatch - Reliability, Planning & Standards I						2,313,221 1,160,718 245,515
17	Total 561 Internally Developed Costs	(Line 14 - Line 15 - Line 16)					906,988

KENTUCKY POWER COMPANY

(1) (2) (3) (4) (5)

		Data Sources				Total
Line	RATE BASE CALCULATION	(See "General Notes")	<u>TO Total</u> NOTE C	All	<u>ocator</u>	<u>Transmission</u>
No.	GROSS PLANT IN SERVICE					
18	Production	(Worksheet A In 1.E)	549,114,863	NA	0.00000	-
19	Less: Production ARO (Enter Negative)	(Worksheet A In 2.E)	(3,614,563)	NA	0.00000	-
20	Transmission	(Worksheet A In 3.C & Ln 142)	473,321,457	DA		471,675,171
21	Less: Transmission ARO (Enter Negative)	(Worksheet A In 4.C& Ln 143)	-	TP	0.99652	-
22	Plus: Transmission Plant-in-Service Additions (Wor	•	N/A	NA	0.00000	N/A
23	Plus: Additional Trans Plant on Transferred Assets	•	N/A	NA	0.00000	N/A
24	Distribution	(Worksheet A In 5.E)	632,096,061	NA	0.00000	-
25 26	Less: Distribution ARO (Enter Negative) General Plant	(Worksheet A In 6.E)	- 24 691 019	NA W/S	0.00000 0.09693	2 264 702
20 27	Less: General Plant ARO (Enter Negative)	(Worksheet A In 7.E) (Worksheet A In 8.E)	34,681,918 (81,055)	W/S	0.09693	3,361,783 (7,857)
28	Intangible Plant	(Worksheet A III 6.E)	16,615,414	W/S	0.09693	1,610,563
29	TOTAL GROSS PLANT	(sum Ins 18 to 28)	1,702,134,094	GP(h)=	0.28002	476,639,661
		(03	.,. 0=, .0 .,00 .	GTD=	0.00000	,,
30	ACCUMULATED DEPRECIATION AND AMORTIZATION	ON				
31	Production	(Worksheet A In 12.E)	261,998,071	NA	0.00000	-
32	Less: Production ARO (Enter Negative)	(Worksheet A In 13.E)	(841,591)	NA	0.00000	-
33	Transmission	(Worksheet A In 14.E & 28.E)	153,749,700	TP1=	0.99587	153,115,039
34	Less: Transmission ARO (Enter Negative)	(Worksheet A In 15.E)	-	TP1=	0.99587	-
35	Plus: Transmission Plant-in-Service Additions (Wor	•	N/A	DA	1.00000	N/A
36	Plus: Additional Projected Deprec on Transferred A	·	N/A	DA	1.00000	N/A
37	Plus: Additional Transmission Depreciation for 201	· · · · ·	N/A	TP1	0.99587	N/A
38	Plus: Additional General & Intangible Depreciation	,	N/A	W/S	0.09693	N/A
39 40	Plus: Additional Accum Deprec on Transferred Ass Distribution	·	N/A	DA	1.00000	N/A
40 41	Less: Distribution ARO (Enter Negative)	(Worksheet A In 16.E) (Worksheet A In 17.E)	166,964,522	NA NA	0.00000 0.00000	<u>-</u>
42	General Plant	(Worksheet A III 17.E)	7,994,972	W/S	0.09693	774,968
43	Less: General Plant ARO (Enter Negative)	(Worksheet A In 19.E)	(8,303)	W/S	0.09693	(805)
44	Intangible Plant	(Worksheet A In 20.E)	19,811,837	W/S	0.09693	1,920,398
45	TOTAL ACCUMULATED DEPRECIATION	(sum Ins 31 to 44)	609,669,208		•	155,809,600
46	NET PLANT IN SERVICE					
47	Production	(ln 18 + ln 19 - ln 31 - ln 32)	284,343,820			-
48	Transmission	(ln 20 + ln 21 - ln 33 - ln 34)	319,571,757			318,560,133
49 50	Plus: Transmission Plant-in-Service Additions (In 2)	,	N/A			N/A
50	Plus: Additional Transmission Depresiation for 200	·	N/A			N/A
51 52	Plus: Additional Transmission Depreciation for 2013 Plus: Additional General & Intangible Depreciation		N/A N/A			N/A N/A
52 53	Plus: Additional Accum Deprec on Transferred Ass		N/A			N/A N/A
54	Distribution	(ln 24 + ln 25 - ln 40 - ln 41)	465,131,539		1	-
55	General Plant	(ln 26 + ln 27 - ln 42 - ln 43)	26,614,194			2,579,764
56	Intangible Plant	(ln 28 - ln 44)	(3,196,423)			(309,835)
57	TOTAL NET PLANT IN SERVICE	(sum Ins 47 to 56)	1,092,464,887	NP(h)=	0.29368	320,830,061
50		(Nata D)				
58 50	DEFERRED TAX ADJUSTMENTS TO RATE BASE	(Note D)	(27.427.454)	NΙΔ		
59 60	Account No. 281.1 (enter negative) Account No. 282.1 (enter negative)	(Worksheet B, In 2 & In 5.E) (Worksheet B, In 7 & In 10.E)	(27,437,154) (195,354,334)	NA DA		(58,003,846)
61	Account No. 283.1 (enter negative)	(Worksheet B, In 12 & In 15.E)	(18,681,066)	DA		(1,091,464)
62	Account No. 190.1	(Worksheet B, In 17 & In 20.E)	16,839,991	DA		3,432,266
63	Account No. 255 (enter negative)	(Worksheet B, In 24 & In 25.E)	-	DA		-
64	TOTAL ADJUSTMENTS	(sum Ins 59 to 63)	(224,632,563)		•	(55,663,044)
65	PLANT HELD FOR FUTURE USE	(Worksheet A In 29.E & In 30.E)	7,436,551	DA		30,592
66	REGULATORY ASSETS	(Worksheet A In 36. (E))	-	DA		-
		· · · · · · · · · · · · · · · · · · ·				
67 68	WORKING CAPITAL	(Note E) (1/8 * In 88)	604.045			688,611
69	Cash Working Capital Transmission Materials & Supplies	(Worksheet C, In 2.F)	691,015 113,716	TP	0.99652	113,320
70	A&G Materials & Supplies	(Worksheet C, In 3.F)	16,793	W/S	0.09693	1,628
70 71	Stores Expense	(Worksheet C, In 4.(D))	-	GP(h)	0.28002	-
72	Prepayments (Account 165) - Labor Allocated	(Worksheet C, In 8.G)	26,494,005	W/S	0.09693	2,568,114
73	Prepayments (Account 165) - Gross Plant	(Worksheet C, In 8.F)	628,070	GP(h)	0.28002	175,875
74	Prepayments (Account 165) - Transmission Only	(Worksheet C, In 8.E)	-	DÀ	1.00000	-
75	Prepayments (Account 165) - Unallocable	(Worksheet C, In 8.D)	(25,607,264)	NA	0.00000	-
76	TOTAL WORKING CAPITAL	(sum Ins 68 to 75)	2,336,335			3,547,548
77	IPP CONTRIBUTIONS FOR CONSTRUCTION	(Note F) (Worksheet D, In 8 (B))	(256,134)	DA	1.00000	(256,134)
78	RATE BASE (sum Ins 57, 64, 65, 66, 76, 77)	· •	877,349,076			268,489,024
. 5	(2 0., 0., 00, 10, 17)		3,0.0,0.0		:	_00,100,021

KENTUCKY POWER COMPANY

(1) (2) (3) (4)

	EXPENSE, TAXES, RETURN & REVENUE	Data Sources				Total
Line	REQUIREMENTS CALCULATION	(See "General Notes")	TO Total	Allo	ocator	<u>Transmission</u>
No.	OPERATION & MAINTENANCE EXPENSE					
79	Production	321.80.b	371,701,916			
80	Distribution	322.156.b	40,373,125			
81	Customer Related Expense	322.164,171,178.b	9,222,773			
82	Regional Marketing Expenses	322.131.b	1,194,322			
83	Transmission	321.112.b	12,202,913			
84	TOTAL O&M EXPENSES	(sum Ins 79 to 83)	434,695,049			
85 00	Less: Total Account 561	(Note G) (Worksheet F, In 14.C)	2,313,221			
86 87	Less: Account 565	(Note H) 321.96.b	4,361,575			
88	Less: Regulatory Deferrals & Amortizations Total O&M Allocable to Transmission	(Note I) (Worksheet F, In 4.C) (Ins 83 - 85 - 86 - 87)	5,528,117	TP	0.99652	5,508,889
00	A desimilatorativa and Open and	200 407 h (Nata II)	40,000,400			
89 90	Administrative and General	323.197.b (Note J) 323.185.b	19,906,103 605,545			
90	Less: Acct. 924, Property Insurance Acct. 9260039 PBOP Expense	PBOP Worksheet O Line 9 & 10, (Note K)	1,994,927			
92	Acct. 9200039 FBOP Expense Acct. 9260057 PBOP Medicare Subsidy	PBOP Worksheet O Line 11, (Note K)	1,994,921			
93	PBOP Expense Billed From AEPSC	PBOP Worksheet O Line 13, (Note K)	193,112			
94	Acct. 928, Reg. Com. Exp.	323.189.b	155,946			
95	Acct. 930.1, Gen. Advert. Exp.	323.191.b	68,468			
96	Acct. 930.2, Misc. Gen. Exp.	323.192.b	290,504			
97	Balance of A & G	(In 89 - sum In 90 to In 96)	16,597,601	W/S	0.09693	1,608,837
98	Plus: Acct. 924, Property Insurance	(In 90)	605,545	GP(h)	0.28002	169,568
99	Acct. 928 - Transmission Specific	Worksheet F In 18.(E) (Note L)	· -	TP ´	0.99664	-
100	Acct 930.1 - Only safety related ads -Direct	Worksheet F In 27.(E) (Note L)	-	TP	0.99664	-
101	Acct 930.2 - Misc Gen. Exp Trans	Worksheet F In 34.(E) (Note L)	21,276	DA	1.00000	21,276
102	Settlement Approved PBOP Recovery	PBOP Worksheet O, Col. C, Line 4, (Note M)	2,573,774	W/S	0.09693	249,481
103	A & G Subtotal	(sum lns 97 to 102)	19,798,196			2,049,161
104	O & M EXPENSE SUBTOTAL	(ln 88 + ln 103)	25,326,313		•	7,558,050
105	Plus: TEA Settlement in Account 565	Company Records (Note H)	-	DA	1.00000	-
106	Plus: Transmission Lease Payments To Affiliates in A			DA	1.00000	-
107	TOTAL O & M EXPENSE	(ln 104 + ln 105 + ln 106)	25,326,313			7,558,050
108	DEPRECIATION AND AMORTIZATION EXPENSE					
109	Production	336.2-6.f	20,867,782	NA	0.00000	-
110	Distribution	336.8.f	22,040,399	NA	0.00000	-
111	Transmission	336.7.f	7,897,690	TP1	0.99587	7,865,089
112	Plus: Transmission Plant-in-Service Additions (Worksl	·	N/A			N/A
113	General	336.10.f	851,375	W/S	0.09693	82,525
114	Intangible	336.1.f	2,809,211	W/S	0.09693	272,302
115	TOTAL DEPRECIATION AND AMORTIZATION	(Ln 109+110+	54,466,457			8,219,917
116	TAVES OTHER THAN INCOME	111+112+113+114)				
116 117	TAXES OTHER THAN INCOME Labor Related	(Note N)				
117	Payroll	Worksheet H In 21.(D)	1,700,019	W/S	0.09693	164,786
119	Plant Related	Worksheet IT in 21.(D)	1,700,019	VV/S	0.09093	104,700
120	Property	Worksheet H In 21.(C) & In 35.(C)	9,357,117	DA		3,583,173
121	Gross Receipts/Sales & Use	Worksheet H In 21.(F)	186,263	NA	0.00000	-
122	Other	Worksheet H In 21.(E)	916,572	GP(h)	0.28002	256,663
123	TOTAL OTHER TAXES	(sum Ins 118 to 122)	12,159,971	, ,	•	4,004,622
	NICOME TAYES	(1)				
124	INCOME TAXES	(Note O)	00 500/			
125	T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =		38.52%			
126 127	EIT=(T/(1-T)) * (1-(WCLTD/WACC)) =		37.79%			
127	where WCLTD=(In 162) and WACC = (In 165) and FIT, SIT & p are as given in Note O.					
129	GRCF=1 / (1 - T) = (from In 125)		1.6265			
130	Amortized Investment Tax Credit (enter negative)	(FF1 p.114, In 19.c)	(278,005)			
131	Income Tax Calculation	(ln 126 * ln 134)	29,116,695			8,910,379
132	ITC adjustment	(In 129 * In 130)	(452,162)	NP(h)	0.29368	(132,789)
133	TOTAL INCOME TAXES	(sum Ins 131 to 132)	28,664,533	()		8,777,590
134	RETURN ON RATE BASE (Rate Base*WACC)	(In 78 * In 165)	77,044,055			23,577,255
135	INTEREST ON IPP CONTRIBUTION FOR CONST. (Note	e F) (Worksheet D, In 2.(B))	8,290	DA	1.00000	8,290
136	(Gains) / Losses on Sales of Plant Held for Future Use (V	Vorksheet N, In 4, Cols. ((F) & (H))	-			-
137	Tax Impact on Net Loss / (Gain) on Sales of Plant Held f	or Future Use (In 136 * In126)	-			-
138	TOTAL REVENUE REQUIREMENT		197,669,618			52,145,724
	(sum lns 107, 115, 123, 133, 134, 135)					

KENTUCKY POWER COMPANY

SUPPORTING CALCULATIONS

ln								
No.	TRANSMISSION PLANT INCLUDED IN PJM TARIFF							
139	Total transmission plant	(In 20)						473,321,457
140	Less transmission plant excluded from PJM Tariff (Note	` ,						-
141	Less transmission plant included in OATT Ancillary Serv	,	. (C)) (Note Q)					1,646,286
142	Transmission plant included in PJM Tariff	(ln 139 - ln 140 - ln 141)	, , ,					471,675,171
143	Percent of transmission plant in PJM Tariff	(In 142 / In 139)					TP=	0.99652
144	WAGES & SALARY ALLOCATOR (W/S)	(Note R)	Direct Payroll	Payroll Billed from AEP Service Corp.	Total			
145	Production	354.20.b	8,667,563	2,494,771	11,162,334	NA	0.00000	-
146	Transmission	354.21.b	1,152,669	1,418,185	2,570,854	TP	0.99652	2,561,912
147	Regional Market Expenses	354.22.b	0	0	-	NA	0.00000	-
148	Distribution	354.23.b	8,394,535	929,541	9,324,076	NA	0.00000	-
149	Other (Excludes A&G)	354.24,25,26.b	1,686,265	1,686,499	3,372,764	NA	0.00000	-
150	Total	(sum lns 145 to 149)	19,901,032	6,528,996	26,430,028			2,561,912
151	Transmission related amount						W/S=	0.09693
152	WEIGHTED AVERAGE COST OF CAPITAL (WACC)							\$
153	Long Term Interest	(Worksheet M, In. 21, col. (E	:))					35,553,541
154	Preferred Dividends	(Worksheet M, In. 56, col. (E	, ,					-
155	Development of Common Stock:	(1.0.1.0.1.001, 00, 00.1 (2	•//					Average
156	Proprietary Capital	(Worksheet M, In. 1, col. (E))					470,012,627
157	Less: Preferred Stock	(Worksheet M, In. 2, col. (E)	•					-
158	Less: Account 216.1	(Worksheet M, In. 3, col. (E)	,					_
159	Less: Account 219	(Worksheet M, In. 4, col. (E)	•					(517,062)
160	Common Stock	(ln 156 - ln 157 - ln 158 - ln 1	,					470,529,689
100	Common Glock	(11.100 11.101 11.100 11.	100)	Capital Structure	Weighting		Cost	170,020,000
161		Average \$		Actual	Cap Limit		(Note S)	Weighted
162	Long Term Debt (Note T) W/S M, In 11, In 22, col. (E))	550,000,000		53.89%	0.00%		0.0646	0.0348
163	Preferred Stock (In 157)	-		0.00%	0.00%		- -	0.0000
164	Commone Stock (In 160)	470,529,689		46.11%	0.00%		11.49%	0.0530
165	Total (Sum Ins 162 to 164)	1,020,529,689		70.11/0	0.0070		WACC=	0.0878
100	10tal (001111113 102 to 10 1)	1,020,029,009					**AUG=	0.0070
166	Capital Structure Equity Limit (Note U)	100.0%						

KENTUCKY POWER COMPANY

<u>Letter</u> <u>Notes</u>

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

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

See Worksheet E for details.

- B The annual and monthly net plant carrying charges on page 1 are used to compute the revenue requirement for RTEP sponsored upgrades or those projects receiving approved incentive-ROE's.
- C Transmission Plant balances in this study reflect the average of the balances at December 31, 2011 and December 31, 2012.
- The total-company balances shown for Accounts 281, 282, 283, 190 only reflect ADIT that relates to utility operations. The balance of Account 255 is reduced by prior flow throughs and is completely excluded if the utility chose to utilize amortization of tax credits against FIT expense. An exception to this is pre-1971 ITC balances, which are required to be taken as an offset to rate base. Account 281 is not allocated. In compliance with FERC Rulemaking RM02-7-000, Asset Retirement Obligation deferrals have been removed from ratebase. Transmission ADIT allocations are shown on WS B.

The company will not include the ADIT portion of deferred hedge gains and losses in rate base.

- E Cash Working Capital assigned to transmission is one-eighth of O&M allocated to transmission, as shown on line 88. It excludes:
 - 1) Load Scheduling & Dispatch Charges in account 561 that are collected in the OATT Ancilliary Services Revenue, as shown on line 85.
 - 2) AEP transmission equalization transfers, as shown on line 86
 - 3) The impact of state regulatory deferrals and amortizations, as shown on line 87
 - 4) All A&G Expenses, as shown on line 103.
- Consistent with Paragraph 657 of Order 2003-A, the amount on line 77 is equal to the balance of IPP System Upgrade Credits owed to transmission customers that made contributions toward the construction of System upgrades, and includes accrued interest and unreturned balance of contributions. The annual interest expense is included on line 135.
- Removes from the cost of service the Load Scheduling and Dispatch expenses booked to accounts 561.1 through 561.8. Expenses recorded in these accounts, with the exception of 561.4 & 561.8 (lines 15 & 16 above) are recovered in Schedule 1A, OATT ancillary services rates. See Worksheet F, lines 5 through 14, for descriptions and the Form 1 Source of these accounts' balances.
- Removes cost of transmission service provided by others to determine the basis of cash working capital on line 88. To the extent such service is incurred to provide the PJM service at issue, e.g. transmission equalization agreement, such costs are added back on lines 105 and 106 to determine the total O&M collected in the formula. The amounts on lines 105 and 106 are also excluded in the calculation of the FCR percentage calculated on lines 5 through 11.
 - The addbacks on lines 105 and 106 of activity recorded in 565 represents inter-company sales or purchases of transmission capacity necessary to meet each AEP company's transmission load relative to their available transmission capacity.

The company records referenced on lines 105 and 106 is the KENTUCKY POWER COMPANY general ledger.

- Removes the impact of state regulatory deferrals or their amortization from O&M expense, applicable only for state regulatory purposes.
- J General Plant and Administrative & General expenses, other than in accounts 924, 928, and 930, will be functionalized based on the Wages & Salaries "W/S" allocator. The allocation basis for accounts 924, 928 and 930 are separately presented in the formula. A change in the allocation method for an account must be approved via a 205 filing with the FERC.
- K These deductions on lines 91 through 93 are to remove from the cost of service the expenses recorded by the company for Postemplyoment Benefits Other than Pensions (PBOP). See Note M below for the recoverable PBOP expense.
- Expenses reported for these A&G accounts will be included in the cost of service only to the extent they are directly assignable to transmission service. Worksheet F allocates these expense items. Acct 928 Includes Regulatory Commission expenses itemized in FERC Form-1 at page 351, column H. FERC Assessment Fees and Annual Charges shall not be allocated to transmission. Only safety-related and educational advertising costs in Account 930.1 are included in the TCOS. Account 930.2 includes the expenses incurred by the transmission function for Associated Business Development revenues given as a credit to the TCOS on Worksheet E.
- M See note K above. Per the settlement in Docket ER08-1329, recoverable PBOP expense is based on an annual total for the operating companies that is ratioed to them based on the total of actual annual PBOP costs, including charges from the AEP Service Corportation. The calculation of the recoverable amount for each company is shown on Worksheet O, and the process for updating the annual total is documented on Attachment F, Allowable PBOP Expense Formula.
- N Includes only FICA, unemployment, highway, property and other assessments charged in the current year. Gross receipts, sales & use and taxes related to income are excluded.
- The currently effective income tax rate, where FIT is the Federal income tax rate; SIT is the State income tax rate, and p = the percentage of federal income tax deductible for state income taxes. See Worksheet G for the development of the Company's composite SIT. A utility that elected to utilize amortization of tax credits against taxable income, rather than book tax credits to Account No. 255 and reduce rate base, must reduce its income tax expense by the amount of the Amortized Investment Tax Credit (Form 1, 266.8.f) (In 130) multiplied by (1/1-T). If the applicable tax rates are zero enter 0.

Inputs Required: FIT = 35.00%

SIT= 5.41% (State Income Tax Rate or Composite SIT. Worksheet G))
p = 0.00% (percent of federal income tax deductible for state purposes)

- P Removes plant excluded from the OATT because it does not meet the PJM's definition of Transmission Facilities or is otherwise ineligible to be recovered under the OATT.
- Q Removes transmission plant (e.g. step-up transformers) included in the development of OATT ancillary service rates and not already removed for reasons indicated in Note P.
- R Includes functional wages & salaries billed by AEP Service Corporation for support of the operating company.
- Long Term Debt cost rate = long-term interest (ln 153) / long term debt (ln 162). Preferred Stock cost rate = preferred dividends (ln 154) / preferred outstanding (ln 163). Common Stock cost rate (ROE) = 11.49%, the rate accepted by FERC in Docket No. ER08-1329. It includes an additional 50 basis points for PJM RTO membership. Interest expense for the true-up WACC is based on actual expenses for the true-up year. The amount of eligible hedging gains or losses included in total interest expense is limited to five basis points of the true-up capital structure. Details and calculations of the true-up weighted average cost of capital are shown on Worksheet M. Eligible Hedging Gains and Losses are defined in the Formula Protocols in the tariff, and on Worksheet M.
- This note only applies to Indiana Michigan Power Company.
- Per Settlement, equity for KENTUCKY POWER COMPANY is limited to 100% of Capital Structure. If the percentage of equity exceeds the cap, the excess is included in weighted percentage of long term debt in the capital structure.

 During the period ended December 31, 2011 the equity cap is in effect. During this period, a change in the cap percentage must be approved via a 205 filing with the FERC.

AEP East Companies Cost of Service Formula Rate Using 2012 FF1 Balances Worksheet A Supporting Plant Balances KENTUCKY POWER COMPANY

(A) (B) (C) (D) (E) <u>Line</u> Balance @ December Balance @ December Average Balance 31, 2011 for 2012 <u>Number</u> Rate Base Item & Supporting Balance **Source of Data** <u>31, 2012</u> NOTE: Functional ARO investment and accumulated depreciation balances shown below are included in the total functional balances shown here. **Plant Investment Balances Production Plant In Service** FF1, page 205 Col.(g) & pg. 204 Col. (b), ln 46 551,473,235 546,756,491 549,114,863 2 **Production Asset Retirement Obligation (ARO)** FF1, page 205&204, Col.(g)&(b), Ins 15,24,34,44 3,614,563 3,614,563 3,614,563 **Transmission Plant In Service** FF1, page 207 Col.(g) & pg. 206 Col. (b), ln 58 490,121,490 456,521,424 3 473,321,457 **Transmission Asset Retirement Obligation** FF1, page 207 Col.(g) & pg. 206 Col. (b), ln 57 5 **Distribution Plant In Service** FF1, page 207 Col.(g) & pg. 206 Col. (b), ln 75 651,987,726 612,204,396 632,096,061 **Distribution Asset Retirement Obligation** FF1, page 207 Col.(g) & pg. 206 Col. (b), ln 74 **General Plant In Service** 35,217,344 34,146,492 34,681,918 FF1, page 207 Col.(g) & pg. 206 Col. (b), ln 99 **General Asset Retirement Obligation** FF1, page 207 Col.(g) & pg. 206 Col. (b), ln 98 81,055 81,055 81,055 9 **Intangible Plant In Service** FF1, page 205 Col.(g) & pg. 204 Col. (b), ln 5 17,734,036 15,496,791 16,615,414 1,705,829,713 10 **Total Property Investment Balance** (Sum of Lines: 3, 1, 5, 7, 9) 1,746,533,831 1,665,125,594 **Total ARO Balance (included in total on line 10)** (Sum of Lines: 4, 2, 6, 8) 3,695,618 3,695,618 3,695,618 11 Accumulated Depreciation & Amortization Balances 12 **Production Accumulated Depreciation** FF1, page 219, Ins 20-24, Col. (b) 267,211,806 256,784,336 261,998,071 13 **Production ARO Accumulated Depreciation** Company Records - Note 1 936,402 746,780 841,591 14 **Transmission Accumulated Depreciation** FF1, page 219, ln 25, Col. (b) 154,839,705 152,659,695 153,749,700 15 **Transmission ARO Accumulated Depreciation** Company Records - Note 1 16 171,225,681 162,703,363 **Distribution Accumulated Depreciation** FF1, page 219, ln 26, Col. (b) 166,964,522 17 **Distribution ARO Accumulated Depreciation** Company Records - Note 1 7,962,549 FF1, page 219, ln 28, Col. (b) 18 **General Accumulated Depreciation** 8,027,395 7,994,972 5,487 8,303 19 **General ARO Accumulated Depreciation** Company Records - Note 1 11,119 20 FF1, page 200, In 21, Col. (b) 20,894,341 18,729,332 19,811,837 **Intangible Accumulated Amortization** 610,519,102 598,904,121 21 **Total Accumulated Depreciation or Amortization** (Sum of Lines: 14, 12, 16, 18, 20) 622,134,082 947,521 752,267 22 **Total ARO Balance (included in total on line 21)** 849,894 (Sum of Lines: 15, 13, 17, 19) **Generation Step-Up Units** 23 **GSU Investment Amount** Company Records - Note 1 1,646,286 1,646,286 1,646,286 24 **GSU Accumulated Depreciation** Company Records - Note 1 648,737 620,586 634,661 1,025,700 (Line 23 - Line 24) 997,548 1,011,624 25 **GSU Net Balance** Transmission Accumulated Depreciation Net of GSU Accumulated Depreciation 26 **Transmission Accumulated Depreciation** (Line 14 Above) 154,839,705 153,749,700 152,659,695 27 **Less: GSU Accumulated Depreciation** (Line 24 Above) 648,737 620,586 634,661 153,115,039 28 **Subtotal of Transmission Net of GSU** (Line 26 - Line 27) 154,190,968 152,039,109 **Plant Held For Future Use** Plant Held For Future Use FF1, page 214, In 47, Col. (d) 7,436,551 7,436,551 7,436,551 29 30 **Transmission Plant Held For Future** Company Records - Note 1 30,592 30,592 30,592 Regulatory Assets and Liabilities Approved for Recovery In Ratebase Note: Regulatory Assets & Liabilities can only be included in ratebase pursuant to a 205 filing with the FERC. 31 32 33 34 35 36 Total Regulatory Deferrals Included in Ratebase

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

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

AEP East Companies Cost of Service Formula Rate Using 2012 FF1 Balances Worksheet B Supporting ADIT and ITC Balances KENTUCKY POWER COMPANY

	(A)	(B)	(C)	(D)	(E)
<u>Line</u> Number	<u>Description</u>	<u>Source</u>	Balance @ December 31, 2012	Balance @ December 31, 2011	Average Balance for 2012
					,
1	Account 281				
2 3	Year End Utility Deferrals Less: ARO Related Deferrals	FF1, p. 272 - 273, ln 8, Col. (k) Company Records - Note 1	26,644,638	28,229,670	27,437,154 -
4	Less: Other Excluded Deferrals	Company Records - Note 1	26,644,638	28,229,670	27,437,154
5	Transmission Related Deferrals	Ln 2 - ln 3 - ln 4	-	-	-
6	Account 282				
7	Year End Utility Deferrals	FF1, p. 274 - 275, ln 5, Col. (k)	198,723,117	191,985,551	195,354,334
8	Less: ARO Related Deferrals	Company Records - Note 1	1,282,377	1,105,092	1,193,735
9	Less: Other Excluded Deferrals	Company Records - Note 1	138,683,771	133,629,737	136,156,754
10	Transmission Related Deferrals	Ln 7 - ln 8 - ln 9	58,756,969	57,250,722	58,003,846
11	Account 283				
12	Year End Utility Deferrals	FF1, p. 276 - 277, ln 9, Col. (k)	18,533,602	18,828,529	18,681,066
13	Less: ARO Related Deferrals	Company Records - Note 1	-	-	-
14	Less: Other Excluded Deferrals	Company Records - Note 1	17,682,265	17,496,938	17,589,602
15	Transmission Related Deferrals	Ln 12 - ln 13 - ln 14	851,337	1,331,591	1,091,464
16	Account 190				
17	Year End Utility Deferrals	FF1, p. 234, ln 8, Col. (c)	13,719,413	19,960,569	16,839,991
18	Less: ARO Related Deferrals	Company Records - Note 1	1,365,791	1,300,433	1,333,112
19	Less: Other Excluded Deferrals	Company Records - Note 1	9,216,403	14,932,824	12,074,614
20	Transmission Related Deferrals	Ln 17 - ln 18 - ln 19	3,137,219	3,727,312	3,432,266
21	Account 255				
22	Year End ITC Balances	FF1, p. 266-267, ln 8, Col. (h)	355,759	633,764	494,762
23	Less: Balances Not Qualified for Ratebase	Company Records - Note 1	355,759	633,764	494,762
24	ITC Balances Includeable Ratebase	Ln 22 - ln 23	-		-
25	Transmission Related Deferrals	Company Records - Note 1	0	0	-

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

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

AEP East Companies Cost of Service Formula Rate Using 2012 FF1 Balances Worksheet C Supporting Working Capital Rate Base Adjustments KENTUCKY POWER COMPANY

			K	ENTUCKY POWER COM	IPANY				
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(1)
			<u>Materia</u>	ls & Supplies					
<u>Line</u> Number	:		<u>Source</u>	Balance @ December 31, 2012	Balance @ December 31, 2011	Average Balance for 2012			
1		Transmission Materials & Supplies	FF1, p. 227, In 8, Col. (c) & (b)	29,645	197,787	113,716			
				6,628	26,958				
3		General Materials & Supplies	FF1, p. 227, ln 11, Col. (c) & (b)			16,793			
4		Stores Expense (Undistributed)	FF1, p. 227, ln 16, Col. (c) & (b)	0	0	-			
			Prepayment	Balance Summary					
5			Average of YE Balance	Excludable <u>Balances</u>	100% Transmission <u>Related</u>	Transmission Plant <u>Related</u>	Transmission Labor <u>Related</u>	Total Included in Ratebase (E)+(F)+(G)	
6 7 8		Totals as of December 31, 2012 Totals as of December 31, 2011 Average Balance	1,569,796 1,459,828 1,514,812	(26,387,585) (24,826,944) (25,607,264)	0	634,845 621,296 628,070	27,322,535 25,665,476 26,494,005	27,957,380 26,286,772 27,122,076	-
9	<u>Acc. No.</u>	<u>Description</u>	Prepayments Account 165 - 1 2012 YE Balance	Balance @ 12/31/201 Excludable Balances	<u>2</u> 100% Transmission <u>Related</u>	Transmission Plant <u>Related</u>	Transmission Labor <u>Related</u>	Total Included in Ratebase (E)+(F)+(G)	<u>Explanation</u>
10 11 12 13 14 15 16 17 18	1650001 165000212 1650009 1650010 1650014 1650016 165001212 165001112 1650021 1650023	Prepaid Insurance Prepaid Taxes Prepaid Carry Cost-Factored AR Prepaid Pension Benefits FAS 158 Qual Contra Asset FAS 112 ASSETS Prepaid Use Taxes Prepaid Sales Taxes Prepaid Insurance - EIS Prepaid Lease	366,671 515,095 13,101 27,322,535 (27,322,535) 0 42,719 294,773 268,174 69,262	- 42,719 294,773 - 69,262		366,671 - 268,174	27,322,535 - - -	27,322,535 - - - - - 268,174 -	Plant Related Insurance Policies Prepaid Fees AR Factoring - Retail Only Prefunded Pension Expense SFAS 158 Offset Use Taxes-Distribution Sales Taxes-Distribution Prepaid Ins EIS Distribution Lease
		Subtotal - Form 1, p 111.57.c	1,569,796	(26,387,585)	0	634,845	27,322,535	27,957,380	
20	<u>Acc. No.</u>	<u>Description</u>	Prepayments Account 165 - I 2011 YE Balance	Excludable Balances	100% Transmission <u>Related</u>	Transmission Plant <u>Related</u>	Transmission Labor <u>Related</u>	Total Included in Ratebase (E)+(F)+(G)	<u>Explanation</u>
21 22 23 24 25 26 27 28 29 30	1650001 165000211 1650009 1650010 1650014 1650016 165001211 165001111 1650021 1650023	Prepaid Insurance Prepaid Taxes Prepaid Carry Cost-Factored AR Prepaid Pension Benefits FAS 158 Qual Contra Asset FAS 112 ASSETS Prepaid Use Taxes Prepaid Sales Taxes Prepaid Insurance - EIS Prepaid Lease	352,266 412,861 20,357 25,665,476 (25,665,476) 0 51,118 348,741 269,030 5,454	- 412,861 20,357		352,266 - 269,030	25,665,476 - - -	352,266 - - 25,665,476 - - -	

(24,826,944)

621,296

1,459,828

Subtotal - Form 1, p 111.57.d

AEP East Companies Cost of Service Formula Rate Using 2012 FF1 Balances Worksheet D Supporting IPP Credits KENTUCKY POWER COMPANY

<u>Line</u> Number	(A) <u>Description</u>	(B) <u>2012</u>
1	Net Funds from IPP Customers 12/31/2011 (2012 FORM 1, P269, line 13.b)	(251,989.00)
2	Interest Accrual (Company Records - Note 1)	(8,290.00)
3	Revenue Credits to Generators (Company Records - Note 1)	-
4 5 6	Other Adjustments Accounting Adjustment (Company Records - Note 1)	
7	Net Funds from IPP Customers 12/31/2012 (2012 FORM 1, P269, line 13.f)	(260,279.00)
8	Average Balance for Year as Indicated in Column ((In 1 + In 7)/2)	(256,134.00)

Note 1 On this worksheet Company Records refers to KENTUCKY POWER COMPANY's general ledger.

AEP East Companies Cost of Service Formula Rate Using 2012 FF1 Balances Worksheet E Supporting Revenue Credits KENTUCKY POWER COMPANY

<u>Line</u> Number	<u>Description</u>	<u>Total</u> <u>Company</u>	Non- Transmission	<u>Transmission</u>
1	Account 450, Forfeited Discounts (FF1 p.300.16.(b); Company Records - Note 1)	3,268,233	3,268,233	-
2	Account 451, Miscellaneous Service Revenues (FF1 p.300.17.(b); Company Records - Note 1)	353,912	340,356	13,556
3	Account 454, Rent from Electric Property (FF1 p.300.19.(b); Company Records - Note 1)	7,006,537	6,980,262	26,275
4	Account 4560015, Associated Business Development - (Company Records - Note 1)	242,814	203,267	39,547
5	Account 456 - Other Electric Revenues - (Company Records - Note 1)	20,241,015	20,241,015	
6	Subtotal - Other Operating Revenues (Company Total equals (FF1 p. 300.26.(b))	31,112,511	31,033,133	79,378
7	Accounts 4470004 & 5, Revenues from Grandfathered Transmission Contracts - (Company Records - Note 1)	-	-	-
8	Total Other Operating Revenues To Reduce Revenue Requirement	31,112,511	31,033,133	79,378

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

AEP East Companies Cost of Service Formula Rate Using 2012 FF1 Balances Worksheet F Supporting Allocation of Specific O&M or A&G Expenses KENTUCKY POWER COMPANY

	(A)	(B)	(C)	(D)	(E) <u>100%</u>	(F)
<u>Line</u>			<u>2012</u>	<u>100%</u>	<u>Transmission</u>	
<u>Number</u>	Item No.	<u>Description</u>	<u>Expense</u>	Non-Transmission	Specific	Explanation
1		Regulatory O&M Deferrals & Amortizations No Applicable Charges for KPCO				
2		No Applicable Charges for KFCO				
3						
4		Total	0			
		Detail of Account 561 Per FERC Form 1				
5	FF1 p 321.84.b	561 - Load Dispatching	0			
6	FF1 p 321.85.b	561.1 - Load Dispatch - Reliability	5,642			
7	FF1 p 321.86.b	561.2 - Load Dispatch - Monitor & Operate Trans System	764,533			
8	FF1 p 321.87.b	561.3 - Load Dispatch - Trans Service & Scheduling	(77)			
9	FF1 p 321.88.b	561.4 - Scheduling, System Control & Dispatch	1,160,718			
10	FF1 p 321.89.b	561.5 - Reliability, Planning and Standards Development	136,890			
11	FF1 p 321.90.b	561.6 - Transmission Service Studies	0			
12	FF1 p 321.91.b	561.7 - Generation Interconnection Studies	0			
13	FF1 p 321.92.b	561.8 - Reliability, Planning and Standards Development Servi	245,515			
14		Total of Account 561	2,313,221			
		Account 928	(0)	(0)		
15	9280000	Regulatory Commission Exp	(3)	(3)	-	
16 17	9280001 9280002	Regulatory Commission Exp-Adm	(4)	(4) 155.054	-	
17	9200002	Regulatory Commission Exp-Case	155,954	155,954	-	
18		Total _	155,947	155,947	-	
.0		<u> </u>				
		<u>Account 930.1</u>				
19	9301000	General Advertising Expenses	8,325	8,325	-	
20	9301001	Newspaper Advertising Space	13,201	13,201	-	
21 22	9301002 9301006	Radio Station Advertising Time Spec Corp Comm Info Proj	2,750	2,750	-	
23	9301000	Publicity	1,278	1,278	-	
24	9301011	Dedications, Tours, & Openings	1,270	1,270	_	
25	9301012	Public Opinion Surveys	2,607	2,607	-	
26	9301014	Video Communications	13	13	-	
	9301015	Other Corporate Comm Exp	40,294	40,294		
27		Total	68,469	68,469	-	
		Account 930.2				
28	9302000	Misc General Expenses	166,816	166,816		
29	9302003	Corporate & Fiscal Expenses	20,488	20,488		
30	9302004	Research, Develop&Demonstr Exp	2,998	2,998		
31	9302006	Assoc Bus Dev Materials Sold	39,799	39,799	_	
32	9302007	Assoc Business Development Exp	60,370	39,094	21,276	
33	9302458	AEPSC Non Affiliated Expense	34	34	04.070	
34		Total	290,505	269,229	21,276	

Formula Rate KPCo WS G State Tax Rate Page 22 of 34

AEP East Companies

Cost of Service Formula Rate Using 2012 FF1 Balances Worksheet G Supporting - Development of Composite State Income Tax Rate KENTUCKY POWER COMPANY

Kentucky Corporate Income Tax Apportionment Factor - Note 2	6.00% 86.11%	- 4-04
Effective State Tax Rate		5.17%
West Virginia Corporate Income Tax	7.75%	
Apportionment Factor - Note 2	0.73%	
Effective State Tax Rate		0.06%
Michigan Business Income Tax	6.00%	
Apportionment Factor - Note 2	0.10%	
Effective State Tax Rate		0.01%
State Income Tax Rate - Ohio	0.00%	
Phase-out Factor Note 1	0.00%	
Apportionment Factor - Note 2	0.00%	
Effective State Tax Rate		0.00%
Illinios Income Tax	9.50%	
Apportionment Factor - Note 2	1.80%	
Effective State Tax Rate		0.17%
Total Effective State Income Tax Rate	- -	5.41%

Note 1 The Ohio State Income Tax is being phased-out prorata over a 5 year period from 2005 through 2009. The taxable portion of income is 0% 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 Activites 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 2012 FF1 Balances Worksheet H Supporting Taxes Other than Income KENTUCKY POWER COMPANY

	(A)	(B)	(C)	(D)	(E)	(F)
Line		Total				
No.	Account	Company	Property	Labor	Other	Non-Allocable
		NOTE 1				
1	Revenue Taxes					
2	Gross Receipts Tax	174,213				174,213
3	Real Estate and Personal Property Taxes					
4	Real and Personal Property - Kentucky	9,354,076	9,354,076			
5	Real and Personal Property - Other	3,041	3,041			
6	Payroll Taxes					
7	Federal Insurance Contribution (FICA)	1,660,027		1,660,027		
8	Federal Unemployment Tax	22,342		22,342		
9	State Unemployment Insurance	17,650		17,650		
10	Production Taxes					
11	State Severance Taxes	-				-
12	Miscellaneous Taxes					
13	State Business & Occupation Tax	-				-
14	State Public Service Commission Fees	927,956			927,956	
15	State Franchise Taxes	(11,849)			(11,849)	
16	State Lic/Registration Fee	465			465	
17	Misc. State and Local Tax	-			-	
18	Sales & Use	11,052				11,052
19	Federal Excise Tax	998				998
20	Michigan Single Business Tax	-				-
21	Total Taxes by Allocable Basis	12,159,971	9,357,117	1,700,019	916,572	186,263
	(Total Company Amount Ties to FFI p.114, Ln 14,(c))					
	NOTE 1: The detail of each total company number and its source in t					
	Fur	nctional Property Tax		Distribution	0	T-1-1
22	Functionalized Net Plant (Hist. TCOS, Lns 212 thru 222)	<u>Production</u> 281,583,267	<u>Transmsission</u> 335,281,785	<u>Distribution</u> 480,762,045	<u>General</u> 27,184,859	<u>Total</u> 1,124,811,957
22	KENTUCKY JURISDICTION	201,303,207	333,201,703	480,702,043	27,104,039	1,124,011,937
23	Percentage of Plant in KENTUCKY JURISDICTION	100.00%	100.00%	100.00%	100.00%	
24	Net Plant in KENTUCKY JURISDICTION (Ln 22 * Ln 23)	281,583,267	335,281,785	480,762,045	27,184,859	1,124,811,957
25	Less: Net Value of Exempted Generation Plant	103,264,979				
26	Taxable Property Basis (Ln 24 - Ln 25)	178,318,288	335,281,785	480,762,045	27,184,859	1,021,546,978
27	Relative Valuation Factor	33%	100%	100%	100%	
28	Weighted Net Plant (Ln 26 * Ln 27)	59,451,317	335,281,785	480,762,045	27,184,859	
29	General Plant Allocator (Ln 28 / (Total - General Plant))	6.79%	38.30%	54.91%	-100.00%	
30	Functionalized General Plant (Ln 29 * General Plant)	1,846,013	10,410,782	14,928,065	(27,184,859)	-
31	Weighted KENTUCKY JURISDICTION Plant (Ln 28 + 30)	61,297,330	345,692,567	495,690,110	U	902,680,006
32	Functional Percentage (Ln 31/Total Ln 31)	6.79%	38.30%	54.91%		0.054.070
33	Functionalized Expense in KENTUCKY JURISDICTION	635,197	3,582,260	5,136,619		9,354,076
34	Total Other Jurisdictions: (Line 5 * Net Plant Allocator)		913			3,041
35	Total Func. Property Taxes (Sum Lns 33, 34)	635,197	3,583,173	5,136,619		9,357,117

AEP East Companies

Cost of Service Formula Rate Using 2012 FF1 Balances Worksheet H-1 Form 1 Source Reference of Company Amounts on WS H KENTUCKY POWER COMPANY

	(A)	(B)	(C)	(D)
Line No.	Annual Tax Expenses by Type (Note 1)	Total Company	FERC FORM 1 Tie-Back	FERC FORM 1 Reference
		Company		
1 2	Revenue Taxes Gross Receipts Tax	174,213		
		, -	30,112 144,101	P.263.1 ln 30 (i) P.263.1 ln 31 (i)
3	Real Estate and Personal Property Taxes	0.254.070	144,101	1 .203.1 111 31 (1)
4	Real and Personal Property - Kentucky	9,354,076	(447) (30,160) (98,374) 9,603,943 18 (104,116) (62,800) 16,699 311 2,257 26,745	P.263 ln 31 (i) P.263 ln 32 (i) P.263 ln 33 (i) P.263 ln 34 (i) P.263 ln 36 (i) P.263 ln 37 (i) P.263 ln 38 (i) P.263 ln 39 (i) P.263 ln 40 (i) P.263.1 ln 2 (i) P.263.1 ln 3 (i)
5	Real and Personal Property - Other	3,041	0.000	D 000 4 1 45 (i)
			2,063 978 -	P.263.1 In 15 (i) P.263.1 In 16 (i)
	D		-	
6 7	Payroll Taxes Federal Insurance Contribution (FICA)	1,660,027		
8	Federal Unemployment Tax	22,342	1,660,027	P.263 In 4 (i)
9	State Unemployment Insurance	17,650	22,342	P.263 In 5 (i)
			17,086 564	P.263 ln 23 (i) P.263.1 ln 20 (i)
10 11	Production Taxes State Severance Taxes	-	-	
12 13	Miscellaneous Taxes State Business & Occupation Tax	_		
14	State Public Service Commission Fees	927,956	-	
		027,000	412,861 515,095	P.263 ln 25 (i) P.263 ln 26 (i)
15	State Franchise Taxes	(11,849)		·
			(22,194) 10,345	P.263.1 In 9 (i) P.263.1 In 10 (i)
16	State Lic/Registration Fee	465	300 15 50 100	P.263 In 19 (i) P.263.1 In 20 (i) P.263.1 In 18 (i) P.263.1 In 21 (i)
17	Misc. State and Local Tax	-		
18	Sales & Use	11,052	-	
			1,247 9,805	P.263 In 27 (i) P.263 In 28 (i)
19	Federal Excise Tax	998	998	P.263 In 7 (i)
20	Michigan Single Business Tax	-	-	(,)
21	Total Taxes by Allocable Basis (Total Company Amount Ties to FFL p 114 L p 14 (c))	12,159,971	12,159,971	

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.

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

AEP East Companies

Cost of Service Formula Rate Using 2012 FF1 Balances Worksheet I Supporting Transmission Plant in Service Additions KENTUCKY POWER COMPANY

(A) (B) (C) (D)	(E) (F)	(G) (H)	(1)
-----------------	---------	---------	-----

I. Calculation of Composite Depreciation Rate

1	Transmission Plant @ Beginning of Historic Period (2012) (P.206, In 58,(b)):	456,521,424
2	Transmission Plant @ End of Historic Period (2012) (P.207, In 58,(g)):	490,121,490
3		946,642,914
4	Average Balance of Transmission Investment	473,321,457
5	Annual Depreciation Expense, Historic TCOS, In 276	7,897,690
6	Composite Depreciation Rate	1.67%
7	Round to 1.67% to Reflect a Composite Life of 60 Years	1.67%

II. Calculation of Property Placed in Service by Month and the Related Depreciation Expense

8	Month in Service	Capi	talized Balance	Composite Annual Depreciation Rate	ı	Annual Depreciation	Mon	thly Depreciation	No. Months Depreciation	First Year Depreciation Expense
9	January	\$	10,342,016	1.67%	\$	172,712	\$	14,393	11	\$ 158,323
10	February	\$	387,925	1.67%	\$	6,478	\$	540	10	\$ 5,400
11	March	\$	539,244	1.67%	\$	9,005	\$	750	9	\$ 6,750
12	April	\$	458,665	1.67%	\$	7,660	\$	638	8	\$ 5,104
13	May	\$	478,248	1.67%	\$	7,987	\$	666	7	\$ 4,662
14	June	\$	507,009	1.67%	\$	8,467	\$	706	6	\$ 4,236
15	July	\$	295,250	1.67%	\$	4,931	\$	411	5	\$ 2,055
16	August	\$	281,260	1.67%	\$	4,697	\$	391	4	\$ 1,564
17	September	\$	898,044	1.67%	\$	14,997	\$	1,250	3	\$ 3,750
18	October	\$	569,934	1.67%	\$	9,518	\$	793	2	\$ 1,586
19	November	\$	314,271	1.67%	\$	5,248	\$	437	1	\$ 437
20	December	\$	2,182,246	1.67%	\$	36,444	\$	3,037	0	\$ -
21	Investment	\$	17,254,112					Dep	oreciation Expense	\$ 193,867

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 2013

	Estimated Cost	
	<u>(000's)</u>	Month in Service
25 Major Zonal Projects	<u> </u>	
26 N/A	\$0	Multiple
		_ ividitiple
27 Subto	tal \$0	
28 PJM Socialized/Beneficiary Allocated Regional Projects		
29 N/A	\$0	_
30 Subto	tal \$0	_

AEP East Companies Cost of Service Formula Rate Using 2012 FF1 Balances Worksheet J Supporting Calculation of PROJECTED PJM RTEP Project Revenue Requirement Billed to Benefiting Zones KENTUCKY POWER COMPANY

SUMMARY OF PROJECTED ANNUAL RTEP REVENUE REQUIREMENTS

PROJECTED YEAR

Rev Require

W Incentives

Incentive Amounts

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, In 164)

Project ROE Incentive Adder

ROE with additional basis point incentive

11.49%

-==ROE Adder Cannot Exceed 125 Basis Points

11.49% -== 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, Ins 162 through164)

	<u>%</u>	Cost	Weighted cost
Long Term Debt	53.40%	6.46%	3.452%
Preferred Stock	0.00%	0.00%	0.000%
Common Stock	46.60%	11.49%	<u>5.355%</u>
		R =	8.806%

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

Rate Base (Projected TCOS, In 78)	292,300,682
R (from A. above)	8.806%
Return (Rate Base x R)	25.741.204

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

Return (from B. above)	25,741,204
Effective Tax Rate (Projected TCOS, In 126)	38.09%
Income Tax Calculation (Return x CIT)	9,805,082
ITC Adjustment	(135,696)
Income Taxes	9,669,386

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, In 1)	55,400,649
T.E.A. & Lease Payments (Projected TCOS, Lns 105 & 106)	-
Return (Projected TCOS, In 134)	25,741,204
Income Taxes (Projected TCOS, In 133)	9,669,386
Annual Revenue Requirement, Less TEA Charges, Return and Taxes	19,990,059

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

Annual Revenue Requirement, Less TEA Charges, Return and Taxes	19,990,059
Return (from I.B. above)	25,741,204
Income Taxes (from I.C. above)	9,669,386
Annual Revenue Requirement, with Basis Point ROE increase	55,400,649
Depreciation (Projected TCOS, In 111)	7,864,601
Annual Rev. Reg. w/ Basis Point ROE increase, less Depreciation	47.536.048

C. Determine FCR with hypothetical basis point ROE increase.

Net Transmission Plant (Projected TCOS, In 48)	334,284,237
Annual Revenue Requirement, with Basis Point ROE increase	55,400,649
FCR with Basis Point increase in ROE	16.57%
Annual Rev. Req, w / Basis Point ROE increase, less Dep.	47,536,048
FCR with Basis Point ROE increase, less Depreciation	14.22%
FCR less Depreciation (Projected TCOS, In 9)	<u>13.78%</u>
Incremental FCR with Basis Point ROE increase, less Depreciation	0.44%

III. Calculation of Composite Depreciation Rate

Transmission Plant @ Beginning of Historic Period (2012) (P.206, In 58,(b)):	456,521,424
Transmission Plant @ End of Historic Period (2012) (P.207, In 58,(g)):	490,121,490
Subtotal	946,642,914
Average Transmission Plant Balance for 2012	473,321,457
Annual Depreciation Rate (Projected TCOS, In 111)	7,897,690
Composite Depreciation Rate	1.67%
Depreciable Life for Composite Depreciation Rate	59.93
Round to nearest whole year	60

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

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

A. Base Plan Facilities

Facilities receiving incentives accepted by FERC in Docket No.

(e.g. ER05-925-000)

Current Projected Year ARR

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

Details			
Investment		Current Year	2008
Service Year (yyyy)	2008	ROE increase accepted by FERC (Basis Points)	-
Service Month (1-12)	1	FCR w/o incentives, less depreciation	13.78%
Useful life	60	FCR w/incentives approved for these facilities, less dep.	13.78%
CIAC (Yes or No)	No	Annual Depreciation Expense	-

CUMULATIVE HISTORY OF PROJECTED ANNUAL REVE	NUE 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.

CIAC (Yes or No)	No	Annual Depreciation	Expense			-	LIFE OF THE P	ROJECT.		
							RTEP Projected		RTEP Projected	
							Rev. Req't.From		Rev. Req't.From	
							Prior Year		Prior Year	
Investment	Beginning	Depreciation	Ending	RTEP Rev. Req't.	RTEP Rev. Req't.	Incentive Rev.	Template		Template	
Year	Balance	Expense	Balance	w/o Incentives	with Incentives **	Requirement ##	w/o Incentives		with Incentives **	
2008	-	-	-	-	-	\$ -				
2009	-	-	-	-	-	\$ -				
2010	-	-	-	-	-	\$ -				
2011	-	-	-	-	-	\$ -				
2012	-	-	-	-	-	\$ -				
2013	-	-	-	-	-	\$ -				
2014	-	-	-	-	-	\$ -				
2015	-	-	-	-	-	\$ -				
2016	-	-	-	-	-	\$ -				
2017	-	-	-	-	-	\$ -				
2018	_	-	_	_	-	\$ -				
2019	_	_	_	_	_	\$ -				
2020	_	_	_	_	_	\$ -				
2021	_	_	_	_	_	\$ -				
2022	_	_	_	_	_	\$ -				
2023	_	_	_	_	_	\$ -				
2024	_	_	_	_	_	\$ -				
2025	_	_	_	_		\$ -				
2026	-	_	_	_		\$ -				
2027	-	_			_	\$ -				
2028					-	•				
2020	-	-	-		-	\$ - ¢				
2029	-	-	-	-	-	\$ -				
2030	-	-	-	-	-	-				
2031	-	-	-	-	-	5 -				
2032	-	-	-	-	-	-				
2033	-	-	-	-	-	-				
2034	-	-	-	-	-	-				
2035	-	-	-	-	-	-				
2036	-	-	-	-	-	\$ -				
2037	-	-	-	-	-	-				
2038	-	-	-	-	-	-				
2039	-	-	-	-	-	-				
2040	-	-	-	-	-	-				
2041	-	-	-	-	-	-				
2042	-	-	-	-	-	-				
2043	-	-	-	-	-	-				
2044	-	-	-	-	-	\$ -				
2045	-	-	-	-	-	\$ -				
2046	-	-	-	-	-	\$ -				
2047	-	-	-	-	-	\$ -				
2048	-	-	-	-	-	\$ -				
2049	-	-	-	-	-	\$ -				
2050	-	-	-	-	-	\$ -				
2051	-	-	-	-	-	\$ -				
2052	-	-	-	-	-	\$ -				
2053	-	-	-	-	-	\$ -				
2054	-	-	-	-	-	\$ -				
2055	-	-	-	-	-	\$ -				
2056	-	-	-	-	-	\$ -				
2057	-	-	-	-	-	\$ -				
2058	-	-	-	-	-	\$ -				
2059	-	-	-	-	-	\$ -				
2060	-	_	_	_	-	\$ -				
2061	_	_	_	_	_	\$ -				
2062	_	_	_	_	_	\$ -				
2063	_	_	_	_	_	\$ -				
2064	_	_	_	_	_	\$ -				
2065	_	_	_	_	_	\$ -				
2066	-	_	_	_	_	\$ -				
2000	-	_	Ī	Ī	-	<u>-</u>				

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

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

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

AEP East Companies Cost of Service Formula Rate Using 2012 FF1 Balances Worksheet K Supporting Calculation of TRUE-UP PJM RTEP Project Revenue Requirement Billed to Benefiting Zones KENTUCKY POWER COMPANY

Page 1 of 2

١.

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

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

ROE w/o incentives (True-U	p TCOS, ln 164	1)	11.49%	
Project ROE Incentive Adde	r		0 <==ROE Adder Cannot Exceed 100 Basis Points	
ROE with additional 0 basis	point incentive		11.49% <== ROE Including Incentives Cannot Exceed 12.5% Until July 1, 2012	
Determine R (cost of long to	erm debt, cost c	of preferred stock and equi	ity percentage is from the True-Up TCOS, lns 162 through164)	
	<u>%</u>	Cost	Weighted cost	
Long Term Debt	53.89%	6.46%	3.484%	
Preferred Stock	0.00%	0.00%	0.000%	
Common Stock	46 11%	11 49%	5 298%	

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

Rate Base (True-Up TCOS, In 78)	268,489,024
R (from A. above)	8.781%
Return (Rate Base x R)	23,577,255

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

Return (from B. above)	23,577,255
Effective Tax Rate (True-Up TCOS, In 126)	37.79%
Income Tax Calculation (Return x CIT)	8,910,379
ITC Adjustment	(132,789)
Income Taxes	8,777,590

11. Calculate Net Plant Carrying Charge Rate (Fixed Charge Rate or FCR) with hypothetical 0 basis point ROE increase.

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

Annual Revenue Requirement (True-Up TCOS, In 1)	52,145,724
T.E.A. & Lease Payments (True-Up TCOS, Lns 105 & 106)	-
Return (True-Up TCOS, In 134)	23,577,255
Income Taxes (True-Up TCOS, In 133)	8,777,590
Annual Revenue Requirement, Less TEA	19,790,879
Charges, Return and Taxes	

B. Determine Annual Revenue Requirement with hypothetical 0 basis point increase in ROE.

Annual Revenue Requirement, Less TEA Charges, Return and Taxes	19,790,879
Return (from I.B. above)	23,577,255
Income Taxes (from I.C. above)	8,777,590
Annual Revenue Requirement, with 0 Basis Point ROE increase	52,145,724
Depreciation (True-Up TCOS, In 111)	7,865,089
Annual Rev. Req, w/ 0 Basis Point ROE	44,280,635
increase, less Depreciation	

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

Net Transmission Plant (True-Up TCOS, In 48) Annual Revenue Requirement, with 0 Basis Point ROE increase FCR with 0 Basis Point increase in ROE	318,560,133 52,145,724 16.37%
Annual Rev. Req, w / 0 Basis Point ROE increase, less Dep.	44,280,635
FCR with 0 Basis Point ROE increase, less Depreciation	13.90%
FCR less Depreciation (True-Up TCOS, In 9)	13.90%
Incremental FCR with 0 Basis Point ROE	0.00%
increase, less Depreciation	

III. Calculation of Composite Depreciation Rate

Transmission Plant @ Beginning of Historic Period () (P.206, In 58,(b)):	456,521,424
Transmission Plant @ End of Historic Period () (P.207, In 58,(g)):	490,121,490
Subtotal	946,642,914
Average Transmission Plant Balance for	473,321,457
Annual Depreciation Rate (True-Up TCOS, In 111)	7,897,690
Composite Depreciation Rate	1.67%
Depreciable Life for Composite Depreciation Rate	59.93
Round to nearest whole year	60

SUMMARY OF TRU	JED-UP ANNUAL REVEI	NUE REQUIRE	MENTS F	OR RTEPPRO	DJECT	ΓS	
		Rev Require	V	V Incentives		Incentive Amo	ounts
TRUE-UP YEAR	2012						
As Proj	ected in Prior Year WS J					\$	-
	Actual after True-up	\$	- \$	5	-	\$	-
 	rue-up of ARR For 2012		-		-		-
	•						

KPCo 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)

2012 Rev Require W Incentives Incentive Amounts Prior Yr Projected Prior Yr True-Up True-Up Adjustment

Project Description:

Details			
Investment		Current Year	2012
Service Year (yyyy)	2008	ROE increase accepted by FERC (Basis Points)	· ·
Service Month (1-12)		FCR w/o incentives, less depreciation	13.90%
Useful life	60	FCR w/incentives approved for these facilities, less dep.	13.90%
CIAC (Voc or No)	No	Annual Depreciation Evenes	

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.

CIAC (Yes or No)	No	Annual Depreciation E	xpense				-	LIFE OF THE P	ROJECT.			
								RTEP Projected		RTEP Projected		
								Rev. Req't.From	RTEP Rev Req't	Rev. Req't.From	RTEP Rev Req't	True-up of
Investment	Beginning	Depreciation	Ending	Average	RTEP Rev. Req't.	RTEP Rev. Req't.	Incentive Rev.	Prior Year WS J	True-up	Prior Year WS J	True-up	Incentive
Year	Balance	Expense	Balance	Balance	w/o Incentives	with Incentives **	Requirement ##	w/o Incentives	w/o Incentives	with Incentives **	with Incentives **	with Incentives **
2008	-	-	-	-	-	-	\$ -		\$ -		\$ -	\$ -
2009	-	-	-	-	-	-	\$ -		\$ -		\$ -	\$ -
2010	-	-	-	-	-	-	\$ -		\$ -		\$ -	\$ -
2011	-	-	-	-	-	-	\$ -		\$ -		\$ -	\$ -
2012	-	_	-	-	_	_	\$ -		\$ -		\$ -	\$ -
2013	-	_	-	-	_	_	\$ -		\$ -		\$ -	\$ -
2014	-	_	_	_	_	_	\$ -		\$ -		\$ -	\$ -
2015	-	_	_	_	_	_	\$ -		\$ -		\$ -	\$ -
2016	_	_	_	_	_	_	\$ -		¢ -		\$ -	\$ -
2017	_	_	_	_	_	_	\$ -		φ • -		φ \$ -	¢ •
2018			_		_		\$ -		¢ _		Ψ - •	ψ - ¢ -
2010	-	_	-	_	_	_	Φ		ψ - Φ		φ •	φ - ¢
2019	-	· ·	-	-	-	•	\$ - ¢		Ф -		ф -	ф •
2020	-	-	-	-	-	-	\$ -		5 -		5 -	5 -
2021	-	-	-	-	-	-	5 -		5 -		\$ -	5 -
2022	-	-	-	-	-	-	-		\$ -		\$ -	\$ -
2023	-	-	-	-	-	-	-		\$ -		-	\$ -
2024	-	-	-	-	-	-	\$ -		\$ -		\$ -	\$ -
2025	-	-	-	-	-	-	\$ -		\$ -		-	-
2026	-	-	-	-	-	-	\$ -		\$ -		\$ -	\$ -
2027	-	-	-	-	-	-	\$ -		\$ -		\$ -	\$ -
2028	-	-	-	-	-	-	\$ -		\$ -		\$ -	\$ -
2029	-	-	-	-	-	-	\$ -		\$ -		\$ -	\$ -
2030	-	-	-	-	-	-	\$ -		\$ -		\$ -	\$ -
2031	-	-	-	-	-	-	\$ -		\$ -		\$ -	\$ -
2032	-	_	-	-	_	_	\$ -		\$ -		\$ -	\$ -
2033	-	_	_	-	_	_	\$ -		\$ -		\$ -	\$ -
2034	_	_	_	_	_	_	\$ -		\$ -		\$ -	\$ -
2035	_	_	_	_	_	_	\$ -		¢ -		\$ -	\$ -
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2038	-	·	- 1	-	•	•	ф -		Ф -		ф -	ф •
2039	-	·	- 1	-	•	•	ф -		Ф -		ф -	ф •
2040	-	-	-	-	-	-	\$ -		5 -		ъ - с	5 -
2041	-	-	-	-	-	-	-		5 -		5 -	5 -
2042	-	-	-	-	-	-	-		5 -		5 -	5 -
2043	-	-	-	-	-	-	-		\$ -		\$ -	5 -
2044	-	-	-	-	-	-	-		\$ -		\$ -	\$ -
2045	-	-	-	-	-	-	\$ -		\$ -		\$ -	\$ -
2046	-	-	-	-	-	-	\$ -		\$ -		-	\$ -
2047	-	-	-	-	-	-	\$ -		\$ -		\$ -	\$ -
2048	-	-	-	-	-	-	\$ -		\$ -		-	-
2049	-	-	-	-	-	-	\$ -		\$ -		-	\$ -
2050	-	-	-	-	-	-	\$ -		\$ -		-	\$ -
2051	-	-	-	-	-	-	\$ -		\$ -		\$ -	-
2052	-	-	-	-	-	-	\$ -		\$ -		\$ -	-
2053	-	-	-	-	-	-	\$ -		\$ -		-	\$ -
2054	-	-	-	-	-	-	\$ -		\$ -		-	\$ -
2055	-	-	-	-	-	-	\$ -		\$ -		-	\$ -
2056	-	-		-	-	-	\$ -		\$ -		-	\$ -
2057	_	_		-	_	_	\$ -		\$ -		-	\$ -
2058	_		_	_	_	_	\$ -		\$ -		-	\$ -
2059	_			_	_	_	\$ -		\$ -		\$ -	\$ -
2060	_	_	_	_	_	_	\$ -		\$ -		\$ -	\$ -
2061	<u>-</u>]	<u> </u>	-			\$ -		\$ -		- \$	\$ -
2062	-	1	·	-	_]	φ - \$ -		φ <u>-</u>		- (¢	· ·
2002	-	· ·	·	-]]	Φ		ψ <u>-</u> ¢		- ψ	- ¢
2063	-	· ·	·	-	_	_	\$ - ¢		ψ -		- φ	- φ
2064	-	_	·	-	_	_	\$ - ¢		φ - ¢		- e	φ - e
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2066	-	-	-	-	-	-	-		5 -		-	-
2067	-	-	-	-	-	-	\$ -		> -		-	\$ -

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

Project Totals

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

Page 2 of 2

AEP East Companies Cost of Service Formula Rate Using 2012 FF1 Balances Worksheet L Supporting Projected Cost of Debt KENTUCKY POWER COMPANY

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

<u>Line</u>	(A)	(B)	(C)	(D)	(E)
<u>Number</u>	<u>Issuance</u>	Principle Outstanding	Interest Rate	Annual Expense (See Note S on Projected Template)	<u>Notes</u>
1	Long Term Debt (FF1.p. 256-257.h)	00,000,000	5.0500/	4.050.000	
2 3	Notes Payable to Parent	20,000,000	5.250%	1,050,000	
Ü					
4	Installment Purchase Contracts (FF1.p. 256				
5	Senior Unsecured Notes - Series D	75,000,000	5.625%	4,218,750	
6	Senior Unsecured Notes - Series E	325,000,000	6.000%	19,500,000	
7 8	Senior Unsecured Notes - 7.250% Senior Unsecured Notes - 8.030%	40,000,000 30,000,000	7.250% 8.030%	2,900,000 2,409,000	
9	Senior Unsecured Notes - 8.030% Senior Unsecured Notes - 8.130%	60,000,000	8.130%	4,878,000	
10	Oction Officedured Notes 0.10070	00,000,000	0.10070	-,070,000	
11					
12				-	
13					
14				-	
4.5					
15 16				_	
17					
18				_	
19				-	
20				-	
21				-	
22				-	
23 24				-	
25					
26					
27	Issuance Discount, Premium, & Expenses:		_		
28	Auction Fees	FF1.p. 256 & 257.Lines Described as F	ees	- 00.050	
29 30	Allowable Hedge Amortization (See Ln 45 Belo Amort of Debt Discount and Expenses	ow) FF1.p. 117.63.c		92,956 471,186	
31	Amort of Debt Premimums (Enter Negative)	FF1.p. 117.65.c		471,100	
01	/ more of Bober rommania (Emer regains)	111.5.111.00.0			
32	Reacquired Debt:				
33	Amortization of Loss	FF1.p. 117.64.c		33,649	
34	Amortization of Gain	FF1.p. 117.66.c		-	
35	Total Interest on Long Term Debt	550,000,000	6.46%	35,553,541	
36	Preferred Stock (FF1.p. 250-251)	Preferred Shares Outstanding			
37		-	0.00%	-	
38				-	
39				-	
40	Dividends on Preferred Stock	-		-	
41	Net Total Hedge Gains and Losses (WS M, L	n 35. (E))		92,956	
42	Total Projected Capital Structure Balance for 2			1,030,018,915	
43	Financial Hedge Recovery Limit - Five Basis I	· · ·		0.0005	
44	Limit of Recoverable Amount	·		515,009	
45	Recoverable Hedge Amortization (Lesser of	f Ln 41 or Ln 44)		92,956	

AEP East Companies Transmission Cost of Service Formula Rate KENTUCKY POWER COMPANY

Worksheet M Supporting Calculation of Capital Structure and Weighted Average Cost of Capital Based on Average of Balances At 12/31/2011 & 12/31/2012

(A)	(B)	(C)	(D)	(E)
Line		Balances @ 12/31/2012	Balances @ 12/31/2011	Average
<u>Developme</u>	nt of Average Balance of Common Equity			
1 Pro	oprietary Capital (112.16.c&d)	479,610,035	460,415,218	470,012,627
2 Les	ss Preferred Stock (Ln 55 Below)	0	0	-
	ss Account 216.1 (112.12.c&d)	0	0	0
	ss Account 219.1 (112.15.c&d)	-408,880	-625,244	-517,062
5 Av	erage Balance of Common Equity	480,018,915	461,040,462	470,529,689
<u>Developme</u>	ent of Cost of Long Term Debt Based on Av	verage Outstanding B	<u>alance</u>	
6 Bo	nds (112.18.c&d)	0	0	0
	ss: Reacquired Bonds (112.19.c&d)	0	0	0
8 LT	Advances from Assoc. Companies (112.20.c&d)	20,000,000	20,000,000	20,000,000
	nior Unsecured Notes (112.21.c&d)	530,000,000	530,000,000	530,000,000
10 Les	ss: Fair Value Hedges (See Note on Ln 12 below)	0	0	0
11 To	tal Average Debt	550,000,000	550,000,000	550,000,000
	TE: The balance of fair value hedges on outstanding		e excluded from the	balance of long
ter	m debt included in the formula's capital structure. (Column H of the FF1)		
13 An	nual Interest Expense for 2012			
14 Inte	erest on Long Term Debt (256-257.33.i)			35,048,706
₄₅ Les	ss: Total Hedge Gain/Expense Accumulated from p 256	-257, col. (i) of FERC		
¹⁵ Fo	m 1 included in Ln 14 and shown in Ln 34 below.			92,956
16 Plu	s: Allowed Hedge Recovery From Ln 39 below.			92,956
17 Am	ort of Debt Discount & Expense (117.63.c)			471,186
	ort of Loss on Reacquired Debt (117.64.c)			33,649
	ss: Amort of Premium on Debt (117.65.c)			-
20 Les	ss: Amort of Gain on Reacquired Debt (117.66.c)			-

CALCULATION OF RECOVERABLE HEDGE GAINS/LOSSES

21 Total Interest Expense (Ln 14 + Ln 17 + Ln 18 - Ln 19 - Ln 20)

22 Average Cost of Debt for 2012 (Ln 21/Ln 11)

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.

					Amortiza	tion Period
HEDGE AMOUNTS BY ISSUANCE (FROM p. 256-257	Total Hedge	Less Excludable Amounts (See	Net Includable	Remaining Unamortized		
(i) of the FERC Form 1)	(Gain)/Loss for 2012	NOTE on Line 23)	Hedge Amount	Balance	Beginning	Endin
24 Senior Unsecured Notes - Series E 25 Senior Unsecured Notes	92,956	•	92,956	433,796 8	eptember 2007	September 2
26 Senior Unsecured Notes	0		-			
	0		-			
27 Senior Unsecured Notes	0		-			
28 Senior Unsecured Notes	0		-			
29 Senior Unsecured Notes	0		-			
30 Senior Unsecured Notes	0		-			
31 Senior Unsecured Notes	0		-			
32 Senior Unsecured Notes 33 Senior Unsecured Notes	0		-			
34 Total Hedge Amortization	92,956	-				
35 Hedge Gain or Loss Prior to Application of Recovery Limi	t (Sum of Lines 24 to 33)		92,956			
36 Total Average Capital Structure Balance for 2012 (True-L			1,020,529,689			
37 Financial Hedge Recovery Limit - Five Basis Points of To	otal Capital		0.0005			
38 Limit of Recoverable Amount	·		510,265			
39 Recoverable Hedge Amortization (Lesser of Ln 35 or	Ln 38)	[92,956			
opment of Cost of Preferred Stock						
Preferred Stock			<u>Average</u>			
40 0% Series - 0 - Dividend Rate (p. 250-251. 7 & 10.a)	0.00%	0.00%				
41 0% Series - 0 - Par Value (p. 250-251. 8.c)	\$ -	\$ -				
42 0% Series - 0 - Shares O/S (p.250-251. 8 & 11.e)	_					
43 0% Series - 0 - Monetary Value (Ln 41 * Ln 42)	-	-	_			
44 0% Series - 0 - Dividend Amount (I n 40 * I n 43)						

35,553,541

6.46%

Preferred Stock			<u>Average</u>	
40 0% Series - 0 - Dividend Rate (p. 250-251. 7 & 10.a)	0.00%	0.00%		
41 0% Series - 0 - Par Value (p. 250-251. 8.c) 42 0% Series - 0 - Shares O/S (p.250-251. 8 & 11.e)	\$ - \$ -	-		
43 0% Series - 0 - Monetary Value (Ln 41 * Ln 42)	-	-	-	
44 0% Series - 0 - Dividend Amount (Ln 40 * Ln 43)	-	-	-	
45 00/ Series Dividend Beta (n. 250 251 a)				
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)	<u>-</u>			
53 0% Series Morietary Value (El151 - El152) 54 0% Series Dividend Amount (Ln 50 * Ln 53)	-	-	- -	
· · · · ·				
55 Balance of Preferred Stock (Lns 43, 48, 53) 56 Dividends on Preferred Stock (Lns 44, 49, 54)		<u>-</u>	 - Year End Total Agrees to FF1 p.112, Ln 3, col (c) & ((4)
57 Average Cost of Preferred Stock (Ln 56/55)	0.00%	0.00%	- Treal Ella Total Agrees to FF F p. 112, Ell 3, col (c) & ((u)

AEP East Companies Cost of Service Formula Rate Using 2012 FF1 Balances Worksheet N - Gains (Losses) on Sales of Plant Held For Future Use KENTUCKY POWER COMPANY

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

	(A)	(B)	(C) Function	(D)	(E)	(F)	(G) Functional	(H) Functionalized	(I) FERC
Line	Date	Property Description	(T) or (G) T = Transmissi G = General	Basis ion	Proceeds	(Gain) / Loss	Allocator	Proceeds (Gain) / Loss	Account
1						-	0.000%	-	
2						-	0.000%	-	
3						-	0.000%	-	
4			N	Net (Gain) or Lo	oss for 2012			-	

AEP East Companies

Cost of Service Formula Rate Using 2012 FF1 Balances Worksheet O - Calculation of Postemployment Benefits Other than Pensions Expenses Allocable to Transmission Service KENTUCKY POWER COMPANY

Total AEP East Operating Company PBOP Settlement Amount

48,100,000

Allocation of PBOP Settlement Amount for 2012

Total Company Amount

Line# Compar	Actual Expense (Including AEPSC Billed ny OPEB)	Ratio of Company Actual to Total	Allocation of PBOB Recovery Allowance	Labor Allocator for 2012	Actual Expense	Allowable Expense	One Year Functional Expense (Over)/Under
	(A) (Line 14)	(B)=(A)/Total (A)	(C)=(B) * 48100000	(D)	(E)=(A) * (D)	(F)=(C) * (D)	(G)=(E) - (F)
1 APCo	11,359,793	27.78%	13,362,440	7.081%	804,397	946,207	(141,809)
2							
3 I&M	10,586,657	25.89%	12,453,006	4.206%	445,250	523,744	(78,494)
4 KPCo	2,188,039	5.35%	2,573,774	9.694%	212,116	249,511	(37,394)
5 KNGP	277,875	0.68%	326,862	13.137%	36,506	42,941	(6,436)
6 OPCo	16,164,303	39.53%	19,013,950	6.771%	1,094,477	1,287,425	(192,948)
7 WPCo	314,520	0.77%	369,968	7.846%	24,676	29,026	(4,350)
8 Sum of Lines	a 1 to 7 40,891,187	•	48,100,000		2,617,422	3,078,853	(461,432)

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

	APCo	<u>I&M</u>	<u>KPCo</u>	KNGSPT	<u>OPCo</u>	<u>WPCo</u>	AEP East Total
9 Direct Charged PBOP Expense per Actuarial Report	10,991,074	9,836,923	1,994,927	247,734	13,628,228	282,183	36,981,069
10 Additional PBOP Ledger Entries (from Company Records)	(669,581)	(45,394)	-	-	1,105,077	-	
11 Medicare Subsidy	-	-	-	-	-	-	-
12 Net Company Expense (Ln 9 + Ln 10 + Ln 11)	10,321,493	9,791,529	1,994,927 -	247,734	14,733,305	282,183	37,371,171
13 PBOP Expenses From AEP Service Corporation (from Company Records)	1,038,300	795,128	193,112	30,141	1,430,998	32,337	3,520,016
14 Company PBOP Expense (Ln 12 + Ln 13)	11,359,793	10,586,657	2,188,039	277,875	16,164,303	314,520	40,891,187

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.

KINGSPORT POWER COMPANY

Line No.						Tr	ansmission Amount
1	REVENUE REQUIREMENT (w/o incentives)	(In 138)	T-4-1	A II -			\$3,760,479
2	REVENUE CREDITS	(Note A) (Worksheet E)	Total 306,055	DA	1.00000	\$	306,055
3	REVENUE REQUIREMENT For All Company Facilities	(In 1 less In 2)				\$	3,454,424
	The Carrying Charge Calculations on lines 6 to 11 belo ssion Enhancement Charges. The total non-incentive r	.		•			
4	Revenue Requirement for PJM Schedule 12 Facilities (w/	o incentives) (Worksheet J)	-	DA	1.00000	\$	-
5	NET PLANT CARRYING CHARGE w/o intra-AEP charges	s or credits or ROE incentives (Note B)					
6	Annual Rate	((ln 1 - ln 105 - ln 106)/((ln 48 + ln 49 + ln 50 +	ln 51 + ln 53) x 100))				21.78%
7	Monthly Rate	(ln 6 / 12)					1.82%
8	NET PLANT CARRYING CHARGE ON LINE 6, w/o depr	eciation or ROF incentives (Note B)					
9	Annual Rate	((ln 1 - ln 105 - ln 106 - ln 111 - ln 112) /((ln 48	+ ln 49 + ln 50 + ln 51 + ln 53) x 100))			18.28%
10	NET PLANT CARRYING CHARGE ON LINE 9, w/o Retur	n, income taxes or ROE incentives (Note B)					
11	Annual Rate	((ln 1 - ln 105 - ln 106 - ln 111 - ln 112- ln 133 -	In 134) /((In 48 + In 49 + In 50 + In 5	1 + ln 53) x 1	00))		6.90%
12	ADDITIONAL REVENUE REQUIREMENT for projects w/	incentive ROE's (Note B) (Worksheet J)					-
13		REVENUE REQUIREMENT FOR SCHED	ULE 1A CHARGES				
1.1	Total Load Dianatah & Cahadulina (Assaurt 564)	Line 95 Below					E0 457
14 15	Total Load Dispatch & Scheduling (Account 561) Less: Load Dispatch - Scheduling, System Control and D	Line 85 Below ispatch Services (321 88 b)					50,457 1,263
16	Less: Load Dispatch - Reliability, Planning & Standards D	• • • • • • • • • • • • • • • • • • • •					0
17	Total 561 Internally Developed Costs	(Line 14 - Line 15 - Line 16)					49,194

KINGSPORT POWER COMPANY

	(1)	(2)	(3)	(4	4)	(5)
	RATE BASE CALCULATION	Data Sources (See "General Notes")	TO Total	Allo	cator	Total <u>Transmission</u>
Line No.	GROSS PLANT IN SERVICE		NOTE C			
18	Production	(Worksheet A In 1.C)	0	NA	0.00000	0
19	Less: Production ARO (Enter Negative)	(Worksheet A In 2.C)	0	NA	0.00000	0
20	Transmission	(Worksheet A In 3.C & Ln 142)	22,330,531	DA		22,330,531
21	Less: Transmission ARO (Enter Negative)	(Worksheet A In 4.C& Ln 143)	0	TP	1.00000	0
22	Plus: Transmission Plant-in-Service Additions (Work	sheet I, In 21.D)	6,128,348	DA	1.00000	6,128,348
23	Plus: Additional Trans Plant on Transferred Assets (•	0	DA	1.00000	0
24	Distribution	(Worksheet A In 5.C)	114,411,136	NA	0.00000	0
25	Less: Distribution ARO (Enter Negative)	(Worksheet A In 6.C)	0	NA	0.00000	0
26	General Plant	(Worksheet A In 7.C)	2,558,752	W/S	0.13137	336,154
27	Less: General Plant ARO (Enter Negative)	(Worksheet A In 8.C)	0	W/S	0.13137	0
28	Intangible Plant	(Worksheet A In 9.C)	1,334,980	W/S	0.13137	175,382
29	TOTAL GROSS PLANT	(sum lns 18 to 28)	146,763,747			28,970,415
30	ACCUMULATED DEPRECIATION AND AMORTIZATION	NC				
31	Production	(Worksheet A In 12.C)	0	NA	0.00000	0
32	Less: Production ARO (Enter Negative)	(Worksheet A In 13.C)	0	NA	0.00000	0
33	Transmission	(Worksheet A In 14.C & 28.C)	10,591,842	TP1=	1.00000	10,591,842
34	Less: Transmission ARO (Enter Negative)	(Worksheet A In 15.C)	0	TP1=	1.00000	0
35	Plus: Transmission Plant-in-Service Additions (Work	sheet I, In 21.I)	71,346	DA	1.00000	71,346
36	Plus: Additional Projected Deprec on Transferred As	ssets (Worksheet I In. 24.D)	0	DA	1.00000	0
37	Plus: Additional Transmission Depreciation for 2013	(ln 111)	533,521	TP1	1.00000	533,521
38	Plus: Additional General & Intangible Depreciation for	or 2013 (ln 113 + ln 114)	124,292	W/S	0.13137	16,329
39	Plus: Additional Accum Deprec on Transferred Asse	· ·	0	DA	1.00000	0
40	Distribution	(Worksheet A In 16.C)	44,733,167	NA	0.00000	0
41	Less: Distribution ARO (Enter Negative)	(Worksheet A In 17.C)	0	NA	0.00000	0
42	General Plant	(Worksheet A In 18.C)	732,776	W/S	0.13137	96,268
43	Less: General Plant ARO (Enter Negative)	(Worksheet A In 19.C)	0	W/S	0.13137	0
44	Intangible Plant	(Worksheet A In 20.C)	1,516,239	W/S	0.13137	199,195
45	TOTAL ACCUMULATED DEPRECIATION	(sum lns 31 to 44)	58,303,183			11,508,500
46	NET PLANT IN SERVICE					
47	Production	(In 18 + In 19 - In 31 - In 32)	0			0
48	Transmission	(In 20 + In 21 - In 33 - In 34)	11,738,689			11,738,689
49	Plus: Transmission Plant-in-Service Additions (In 22	· · · · · · · · · · · · · · · · · · ·	6,057,002			6,057,002
50	Plus: Additional Trans Plant on Transferred Assets	,	0			0
51	Plus: Additional Transmission Depreciation for 2013		(533,521)			(533,521)
52	Plus: Additional General & Intangible Depreciation for	·	(124,292)			(16,329)
53	Plus: Additional Accum Deprec on Transferred Asse	· · · · · · · · · · · · · · · · · · ·	0			0
54	Distribution	(ln 24 + ln 25 - ln 40 - ln 41)	69,677,969			0
55	General Plant	(ln 26 + ln 27 - ln 42 - ln 43)	1,825,976			239,886
56	Intangible Plant	(ln 28 - ln 44)	(181,259)			(23,813)
57	TOTAL NET PLANT IN SERVICE	(sum lns 47 to 56)	88,460,564			17,461,915
58	DEFERRED TAX ADJUSTMENTS TO RATE BASE	(Note D)				
59	Account No. 281.1 (enter negative)	(Worksheet B, In 2 & In 5.C)	0	NA		0
60	Account No. 282.1 (enter negative)	(Worksheet B, In 7 & In 10.C)	(16,710,005)	DA		(3,243,399)
61	Account No. 283.1 (enter negative)	(Worksheet B, In 12 & In 15.C)	(902,525)	DA		(119,483)
62	Account No. 190.1	(Worksheet B, ln 17 & ln 20.C)	477,622	DA		20,136
63	Account No. 255 (enter negative)	(Worksheet B, In 24 & In 25.C)	(55,004)	DA		(11,643)
64	TOTAL ADJUSTMENTS	(sum Ins 59 to 63)	(17,189,912)			(3,354,389)
65	PLANT HELD FOR FUTURE USE	(Worksheet A In 29.C & In 30.C)	425,220	DA		0
66	REGULATORY ASSETS	(Worksheet A In 36. (C))	0	DA		0
67	WORKING CAPITAL	(Note E)				
68		(Note E) (1/8 * In 88)	57,983			57 OO2
69	Cash Working Capital Transmission Materials & Supplies	(Worksheet C, In 2.(D))	232	TP	1.00000	57,983 232
70	A&G Materials & Supplies	(Worksheet C, In 3.(D))	3,123	W/S	0.13137	410
71	Stores Expense	(Worksheet C, In 4.(D))	0,123	GP(h)	0.16242	710
72	Prepayments (Account 165) - Labor Allocated	(Worksheet C, In 4.(b))	5,767,913	W/S	0.13137	757,755
73	Prepayments (Account 165) - Cross Plant	(Worksheet C, In 6.F)	147,105	GP(h)	0.16242	23,893
74	Prepayments (Account 165) - Transmission Only	(Worksheet C, In 6.E)	0	DA	1.00000	20,000
75	Prepayments (Account 165) - Unallocable	(Worksheet C, In 6.D)	(3,499,352)	NA	0.00000	0
76	TOTAL WORKING CAPITAL	(sum lns 68 to 75)	2,477,004			840,273
77	IPP CONTRIBUTIONS FOR CONSTRUCTION	(Note F) (Worksheet D, In 7.B)	_	DA	1.00000	-
		(. 1010 .) (11011000 D, III 1.D)	71.170.070			44047
78	RATE BASE (sum Ins 57, 64, 65, 66, 76, 77)		<u>74,172,876</u>			14,947,799

KINGSPORT POWER COMPANY

(1) (2) (3) (5) (4)

Line	EXPENSE, TAXES, RETURN & REVENUE REQUIREMENTS CALCULATION	Data Sources (See "General Notes")	TO Total	<u>Allocator</u>		Total <u>Transmission</u>
No.	OPERATION & MAINTENANCE EXPENSE					
79	Production	321.80.b	124,517,930			
80	Distribution	322.156.b	5,354,724			
81	Customer Related Expense	322.164,171,178.b	1,611,378			
82	Regional Marketing Expenses	322.131.b				
83	Transmission	321.112.b	514,322			
84	TOTAL O&M EXPENSES	(sum lns 79 to 83)	131,998,354			
85	Less: Total Account 561	(Note G) (Worksheet F, In 14.C)	50,457			
86	Less: Account 565	(Note H) 321.96.b	-			
87	Less: State Regulatory Deferrals & Amortizations	(Note I) (Worksheet F, In 4.C)	-	TD	4 00000	400.005
88	Total O&M Allocable to Transmission	(Ins 83 - 85 - 86 - 87)	463,865	TP	1.00000	463,865
89	Administrative and General	323.197.b (Note J)	2,534,881			
90	Less: Acct. 924, Property Insurance	323.185.b	195,760			
91	Acct. 9260039 PBOP Expense	PBOP Worksheet O Line 9 & 10, (Note K)	247,734			
92	Acct. 9260057 PBOP Medicare Subsidy	PBOP Worksheet O Line 11, (Note K)	· · ·			
93	PBOP Expense Billed From AEPSC	PBOP Worksheet O Line 13, (Note K)	30,141			
94	Acct. 928, Reg. Com. Exp.	323.189.b	37			
95 06	Acct. 930.1, Gen. Advert. Exp.	323.191.b	3,024			
96 07	Acct. 930.2, Misc. Gen. Exp.	323.192.b	185,103	\\/\C	0.40407	046.075
97 98	Balance of A & G	(ln 89 - sum ln 90 to ln 96)	1,873,082	W/S	0.13137 0.16242	246,075
96 99	Plus: Acct. 924, Property Insurance Acct. 928 - Transmission Specific	(In 90) Worksheet F In 18.(E) (Note L)	195,760	GP(h) TP	1.00000	31,795
100	Acct 930.1 - Only safety related ads -Direct	Worksheet F In 26.(E) (Note L)	- -	TP	1.00000	-
101	Acct 930.1 - Only safety related ads -bliect Acct 930.2 - Misc Gen. Exp Trans	Worksheet F In 33.(E) (Note L)	172,732	DA	1.00000	172,732
102	Settlement Approved PBOP Recovery	PBOP Worksheet O, Col. C, Line 5, (Note M)	326,862	W/S	0.13137	42,941
103	A & G Subtotal	(sum lns 97 to 102)	2,568,436	*****	0.10107	493,543
104	O & M EXPENSE SUBTOTAL	(ln 88 + ln 103)	3,032,301			957,408
105	Plus: TEA Settlement in Account 565	Company Records (Note H)	-	DA	1.00000	-
106	Plus: Transmission Lease Payments To Affiliates in Acc		-	DA	1.00000	-
107	TOTAL O & M EXPENSE	(ln 104 + ln 105 + ln 106)	3,032,301			957,408
108	DEPRECIATION AND AMORTIZATION EXPENSE					
109	Production	336.2-6.f	-	NA	0.00000	_
110	Distribution	336.8.f	3,905,071	NA	0.00000	_
111	Transmission	336.7.f	533,521	TP1	1.00000	533,521
112	Plus: Transmission Plant-in-Service Additions (Workshe	eet I In 21.I)	71,346	DA	1.00000	71,346
113	General	336.10.f	100,853	W/S	0.13137	13,249
114	Intangible	336.1.f	23,439	W/S	0.13137	3,079
115	TOTAL DEPRECIATION AND AMORTIZATION	(Lns 109+110+111 +112+113+114)	4,634,230			621,196
116	TAXES OTHER THAN INCOME	(Note N)				
117	Labor Related					
118	Payroll	Worksheet H In 21.(D)	151,897	W/S	0.13137	19,955
119	Plant Related					
120	Property	Worksheet H In 21.(C) & In 35.(C)	914,068	DA		131,791
121	Gross Receipts/Sales & Use	Worksheet H In 21.(F)	3,847,999	NA OF (1)	0.00000	-
122	Other	Worksheet H In 21.(E)	404,905	GP(h)	0.16242	65,765
123	TOTAL OTHER TAXES	(sum lns 118 to 122)	5,318,869			217,511
124	INCOME TAXES	(Note O)				
125	T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =		39.20%			
126	EIT=(T/(1-T)) * (1-(WCLTD/WACC)) =		51.06%			
127	where WCLTD=(In 162) and WACC = (In 165)					
128	and FIT, SIT & p are as given in Note O.					
129	GRCF=1 / (1 - T) = (from In 125)		1.6447			
130	Amortized Investment Tax Credit (enter negative)	(FF1 p.114, ln 19.c)	-			
131	Income Tax Calculation	(ln 126 * ln 134)	3,294,746			663,979
132	ITC adjustment	(ln 129 * ln 130)	<u>-</u>	NP(h)	0.14393	<u> </u>
133	TOTAL INCOME TAXES	(sum Ins 131 to 132)	3,294,746			663,979
134	RETURN ON RATE BASE (Rate Base * WACC)	(In 78 * In 165)	6,452,677			1,300,385
135	INTEREST ON IPP CONTRIBUTION FOR CONST. (Note	F) (Worksheet D, In 2.(B))	-	DA	1.00000	-
136	(Gains) / Losses on Sales of Plant Held for Future Use (Wo	orksheet N, In 4, Cols. ((F) & (H))	-			-
137	Tax Impact on (Gains) / Losses on Sales of Plant Held for	Future Use (In 136 * In126)	-			-
138	TOTAL REVENUE REQUIREMENT		22,732,823			3,760,479
	(cum lnc 107 115 122 122 124 125 126 127)					

(sum Ins 107, 115, 123, 133, 134, 135, 136, 137)

KINGSPORT POWER COMPANY

SUPPORTING CALCULATIONS

ln								
No.	TRANSMISSION PLANT INCLUDED IN PJM TARIFF							
139	Total transmission plant	(ln 20)						22,330,531
140	Less transmission plant excluded from PJM Tariff (Note	P)						-
141	Less transmission plant included in OATT Ancillary Servi	ces (Worksheet A, In 23, Col. (C)) (Note Q)					-
142	Transmission plant included in PJM Tariff	(In 139 - In 140 - In 141)					_	22,330,531
143	Percent of transmission plant in PJM Tariff	(In 142 / In 139)					TP	1.00000
				Payroll Billed from				
144	WAGES & SALARY ALLOCATOR (W/S)	(Note R)	Direct Payroll	AEP Service Corp.	Total			
145	Production	354.20.b	0	0	-	NA	0.00000	-
146	Transmission	354.21.b	230,280	104,609	334,889	TP	1.00000	334,889
147	Regional Market Expenses	354.22.b	0	0	-	NA	0.00000	-
148	Distribution	354.23.b	1,270,337	257,864	1,528,201	NA	0.00000	-
149	Other (Excludes A&G)	354.24,25,26.b	278,930	407,103	686,033	NA	0.00000	<u>-</u>
150	Total	(sum lns 145 to 149)	1,779,547	769,576	2,549,123			334,889
151	Transmission related amount						W/S=	0.13137
152	WEIGHTED AVERAGE COST OF CAPITAL (WACC)							\$
153	Long Term Interest	(Worksheet L, In. 35, col. (D))					_	904,000
154	Preferred Dividends	(Worksheet L, In. 40, col. (D))						-
155	Development of Common Stock:	(**************************************						
156	Proprietary Capital	(FF1 p 112, Ln 16.c)						29,956,296
157	Less: Preferred Stock	(FF1 p 112, Ln 3.c)						-
158	Less: Account 216.1	(FF1 p 112, Ln 12.c)						-
159	Less: Account 219	(FF1 p 112, Ln 15.c)						916
160	Common Stock	(In 156 - In 157 - In 158 - In 159	9)				_	29,955,380
404				Φ.	0/		Cost	Mainlete d
161	Lange Tarres Dolet (Note T) Washington Lange OF 111 (D)			\$	% 40.04%		(Note S)	Weighted
162	Long Term Debt (Note T) Worksheet L, In 35, col. (B))			20,000,000	40.04%		0.0452	0.0181
163	Preferred Stock (In 157)			20.055.200	0.00%		- 11 /00/	0.0000
164	Common Stock (In 160)			29,955,380	59.96%		11.49%	0.0689
165	Total (Sum Ins 162 to 164)			49,955,380			WACC=	0.0870

AEP East Companies

Transmission Cost of Service Formula Rate
Utilizing Historic Cost Data for 2012 and Projected Net Plant at Year-End 2013

KINGSPORT POWER COMPANY

<u>Notes</u>

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

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

See Worksheet E for details.

- B The annual and monthly net plant carrying charges on page 1 are used to compute the revenue requirement for RTEP sponsored upgrades or those projects receiving approved incentive-ROE's.
- C Transmission Plant balances in this study are projected as of December 31, 2013. Other ratebase amounts are as of December 31, 2012.
- The total-company balances shown for Accounts 281, 282, 283, 190 only reflect ADIT that relates to utility operations. The balance of Account 255 is reduced by prior flow throughs and is completely excluded if the utility chose to utilize amortization of tax credits against FIT expense. An exception to this is pre-1971 ITC balances, which are required to be taken as an offset to rate base. Account 281 is not allocated. In compliance with FERC Rulemaking RM02-7-000, Asset Retirement Obligation deferrals have been removed from ratebase. Transmission ADIT allocations are shown on WS B.

The company will not include the ADIT portion of deferred hedge gains and losses in rate base.

- E Cash Working Capital assigned to transmission is one-eighth of O&M allocated to transmission, as shown on line 88. It excludes:
 - 1) Load Scheduling & Dispatch Charges in account 561 that are collected in the OATT Ancilliary Services Revenue, as shown on line 85.
 - 2) AEP transmission equalization transfers, as shown on line 86
 - 3) The impact of state regulatory deferrals and amortizations, as shown on line 87
 - 4) All A&G Expenses, as shown on line 103.
- Consistent with Paragraph 657 of Order 2003-A, the amount on line 77 is equal to the balance of IPP System Upgrade Credits owed to transmission customers that made contributions toward the construction of System upgrades, and includes accrued interest and unreturned balance of contributions. The annual interest expense is included on line 135.
- Removes from the cost of service the Load Scheduling and Dispatch expenses booked to accounts 561.1 through 561.8. Expenses recorded in these accounts, with the exception of 561.4 & 561.8 (lines 15 & 16 above) are recovered in Schedule 1A, OATT ancillary services rates. See Worksheet F, lines 5 through 14, for descriptions and the Form 1 Source of these accounts' balances.
- H Removes cost of transmission service provided by others to determine the basis of cash working capital on line 88. To the extent such service is incurred to provide the PJM service at issue, e.g. transmission equalization agreement, such costs are added back on lines 105 and 106 to determine the total O&M collected in the formula. The amounts on lines 105 and 106 are also excluded in the calculation of the FCR percentage calculated on lines 5 through 11.

 The addbacks on lines 105 and 106 of activity recorded in 565 represents inter-company sales or purchases of transmission capacity necessary to meet each AEP

company's transmission load relative to their available transmission capacity.

The company records referenced on lines 105 and 106 is the KINGSPORT POWER COMPANY general ledger.

- I Removes the impact of state regulatory deferrals or their amortization from O&M expense.
- J General Plant and Administrative & General expenses, other than in accounts 924, 928, and 930, will be functionalized based on the Wages & Salaries "W/S" allocator. The allocation basis for accounts 924, 928 and 930 are separately presented in the formula. A change in the allocation method for an account must be approved via a 205 filing with the FERC.
- K These deductions on lines 91 through 93 are to remove from the cost of service the expenses recorded by the company for Postemployment Benefits Other than Pensions (PBOP). See Note M below for the recoverable PBOP expense.
- Expenses reported for these A&G accounts will be included in the cost of service only to the extent they are directly assignable to transmission service. Worksheet F allocates these expense items. Acct 928 Includes Regulatory Commission expenses itemized in FERC Form-1 at page 351, column H. FERC Assessment Fees and Annual Charges shall not be allocated to transmission. Only safety-related and educational advertising costs in Account 930.1 are included in the TCOS. Account 930.2 includes the expenses incurred by the transmission function for Associated Business Development revenues given as a credit to the TCOS on Worksheet E.
- See note K above. Per the settlement in Docket ER08-1329, recoverable PBOP expense is based on an annual total for the operating companies that is ratioed to them based on the total of actual annual PBOP costs, including charges from the AEP Service Corportation. The calculation of the recoverable amount for each company is shown on Worksheet O, and the process for updating the annual total is documented on Attachment F, Allowable PBOP Expense Formula.
- N Includes only FICA, unemployment, highway, property and other assessments charged in the current year. Gross receipts, sales & use and taxes related to income are excluded.
 - The currently effective income tax rate, where FIT is the Federal income tax rate; SIT is the State income tax rate, and p = the percentage of federal income tax deductible for state income taxes. See Worksheet G for the development of the Company's composite SIT. A utility that elected to utilize amortization of tax credits against taxable income, rather than book tax credits to Account No. 255 and reduce rate base, must reduce its income tax expense by the amount of the Amortized Investment Tax Credit (Form 1, 266.8.f) (In 130) multiplied by (1/1-T). If the applicable tax rates are zero enter 0.

Inputs Required: FIT = 35.00%

SIT= 35.00%

6.46% (State Income Tax Rate or Composite SIT. Worksheet G))

p = 0.00% (percent of federal income tax deductible for state purposes)

- P Removes plant excluded from the OATT because it does not meet the PJM's definition of Transmission Facilities or is otherwise ineligible to be recovered under the OATT.
- Q Removes transmission plant (e.g. step-up transformers) included in the development of OATT ancillary service rates and not already removed for reasons indicated in Note P.
- R Includes functional wages & salaries billed by AEP Service Corporation for support of the operating company.
- S Long Term Debt cost rate = long-term interest (ln 153) / long term debt (ln 162). Preferred Stock cost rate = preferred dividends (ln 154) / preferred outstanding (ln 163). Common Stock cost rate (ROE) = 11.49%, the rate accepted by FERC in Docket No. ER08-1329. It includes an additional 50 basis points for PJM RTO membership. In the Projected & Historic templates, the interest expense on long-term debt is the sum of a full year's interest expense at the coupon rate for each issuance outstanding as of December 31 of the historic year. The projected expense for variable rate debt will be based on the effective rate at December 31. These conventions ensure that the expense used in the projection will reflect a full year, similar to the actual expense that will appear in the subsequent true-up of the projection, and minimize the impact on the true-up of using a partial year interest expense. The projection will reflect the actual historic-year expense recorded for issuance expenses, discounts and premiums, and gains or losses on reacquired debt. Eligible hedging gains or losses will be limited to five basis points of the projected capital structure. Details and calculations are shown on Worksheet L.
- T This note only applies to Indiana Michigan Power Company.
- U This note only applies to the true-up template.

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KINGSPORT POWER COMPANY

Line No.						ansmission Amount
166	REVENUE REQUIREMENT (w/o incentives)	(In 303)	Total	Allo	ootor	\$2,965,411
167	REVENUE CREDITS	(Note A) (Worksheet E)	Total 306,055	DA	1.00000	\$ 306,055
168	REVENUE REQUIREMENT For All Company Facilities	(In 166 less In 167)				\$ 2,659,356
	The Carrying Charge Calculations on lines 171 to 176 be ission Enhancement Charges. The total non-incentive re		_			
169	Not applicable on this template					
170 171 172	NET PLANT CARRYING CHARGE w/o intra-AEP charges Annual Rate Monthly Rate	or credits or ROE incentives (Note B) ((In 166 - In 270 - In 271)/ In 213 x 100) (In 171 / 12)				25.26% 2.11%
173 174	NET PLANT CARRYING CHARGE ON LINE 171, w/o dep Annual Rate	reciation or ROE incentives (Note B) ((In 166 - In 270 - In 271 - In 276) / In 213 x 100)				20.72%
175 176	NET PLANT CARRYING CHARGE ON LINE 174, w/o Retu Annual Rate	urn, income taxes or ROE incentives (Note B) ((In 166 - In 270 - In 271 - In 276 - In 298 - In 299)) / In 213 x 100)			10.15%
177	Not applicable on this template					
178		REVENUE REQUIREMENT FOR	SCHEDULE 1A CHARGES			
179 180 181	Total Load Dispatch & Scheduling (Account 561) Less: Load Dispatch - Scheduling, System Control and Dis Less: Load Dispatch - Reliability, Planning & Standards De					50,457 1,263 0
182	Total 561 Internally Developed Costs	(Line 179 - Line 180 - Line 181)				49,194

KINGSPORT POWER COMPANY

(1) (2) (3)

		Data Sources				Total
Line	RATE BASE CALCULATION	(See "General Notes")	<u>TO Total</u> <u>NOTE C</u>	Alloc	<u>cator</u>	<u>Transmission</u>
No.	GROSS PLANT IN SERVICE					
183	Production	(Worksheet A In 1.C)	-	NA	0.00000	-
184	Less: Production ARO (Enter Negative)	(Worksheet A In 2.C)	-	NA	0.00000	-
185	Transmission	(Worksheet A In 3.C & Ln 307)	22,330,531	DA		22,330,531
186	Less: Transmission ARO (Enter Negative)	(Worksheet A In 4.C& Ln 308)		TP	1.00000	
187	Plus: Transmission Plant-in-Service Additions (Works	,	N/A	NA	0.00000	N/A
188	Plus: Additional Trans Plant on Transferred Assets (W	,	N/A	NA	0.00000	N/A
189	Distribution	(Worksheet A In 5.C)	114,411,136	NA	0.00000	-
190	Less: Distribution ARO (Enter Negative)	(Worksheet A In 6.C)	-	NA	0.00000	-
191	General Plant	(Worksheet A In 7.C)	2,558,752	W/S	0.13137	336,154
192	Less: General Plant ARO (Enter Negative)	(Worksheet A In 8.C)	-	W/S	0.13137	-
193	Intangible Plant	(Worksheet A In 9.C)	1,334,980	W/S	0.13137	175,382
194	TOTAL GROSS PLANT	(sum Ins 183 to 193)	140,635,399	GP(h)= GTD=	0.162420 0.16330	22,842,067
195	ACCUMULATED DEPRECIATION AND AMORTIZATION	N		5.12	0.1.0000	
196	Production	(Worksheet A In 12.C)	-	NA	0.00000	-
197	Less: Production ARO (Enter Negative)	(Worksheet A In 13.C)	-	NA	0.00000	-
198	Transmission	(Worksheet A In 14.C & 28.C)	10,591,842	TP1=	1.00000	10,591,842
199	Less: Transmission ARO (Enter Negative)	(Worksheet A In 15.C)	- · · · · · · · · · · · · · · · · · · ·	TP1=	1.00000	, , -
200	Plus: Transmission Plant-in-Service Additions (Works	,	N/A	DA	1.00000	N/A
201	Plus: Additional Projected Deprec on Transferred Ass	•	N/A	DA	1.00000	N/A
202	Plus: Additional Transmission Depreciation for 2013 (,	N/A	TP1	1.00000	N/A
203	Plus: Additional General & Intangible Depreciation for		N/A	W/S	0.13137	N/A
204	Plus: Additional Accum Deprec on Transferred Assets		N/A	DA	1.00000	N/A
205	Distribution	(Worksheet A In 16.C)	44,733,167	NA	0.00000	-
206	Less: Distribution ARO (Enter Negative)	(Worksheet A In 17.C)	-	NA	0.00000	-
207	General Plant	(Worksheet A In 18.C)	732,776	W/S	0.13137	96,268
208	Less: General Plant ARO (Enter Negative)	(Worksheet A In 19.C)	- ,	W/S	0.13137	-
209	Intangible Plant	(Worksheet A In 20.C)	1,516,239	W/S	0.13137	199,195
210	TOTAL ACCUMULATED DEPRECIATION	(sum Ins 196 to 209)	57,574,024			10,887,305
044	NET DI ANTIN CEDVICE					
211	NET PLANT IN SERVICE	(la 402 : la 404 la 400 la 407)				
212	Production	(ln 183 + ln 184 - ln 196 - ln 197)	-			-
213	Transmission Plus: Transmission Plant-in-Service Additions (In 187)	(ln 185 + ln 186 - ln 198 - ln 199)	11,738,689 N/A			11,738,689 N/A
214	,	,	N/A N/A			N/A
215	Plus: Additional Transplination Transferred Assets (Ir	•				
216	Plus: Additional Transmission Depreciation for 2013 (•	N/A			N/A
217	Plus: Additional General & Intangible Depreciation for		N/A			N/A
218	Plus: Additional Accum Deprec on Transferred Assets		N/A			N/A
219	Distribution Congred Plant	(ln 189 + ln 190 - ln 205 - ln 206)	69,677,969			-
220 221	General Plant	(ln 191 + ln 192 - ln 207 - ln 208)	1,825,976			239,886
221 222	Intangible Plant TOTAL NET PLANT IN SERVICE	(In 193 - In 209) (sum Ins 212 to 221)	(181,259) 83,061,375	ND/b_	0.143927	(23,813)
222	TOTAL NET PLANT IN SERVICE	(Suiti itis 212 to 221)	03,001,373	NP(h)=	0.143927	11,954,762
223	DEFERRED TAX ADJUSTMENTS TO RATE BASE	(Note D)				
223 224	Account No. 281.1 (enter negative)	(Note D) (Worksheet B, In 2 & In 5.C)	_	NA		
22 4 225	Account No. 281.1 (enter negative)	(Worksheet B, In 7 & In 10.C)	(16,710,005)	DA		(3,243,399)
226	Account No. 283.1 (enter negative)	(Worksheet B, In 12 & In 15.C)	(902,525)	DA		(3,243,399)
220 227	Account No. 190.1	(Worksheet B, In 17 & In 20.C)	(902,323) 477,622	DA		20,136
228	Account No. 255 (enter negative)	(Worksheet B, In 24 & In 25.C)	(55,004)	DA		(11,643)
229	TOTAL ADJUSTMENTS	(sum Ins 224 to 228)	(17,189,912)			(3,354,389)
225	TO THE ADDOCTMENTO	(3411 113 224 to 220)	(17,100,012)			(0,004,000)
230	PLANT HELD FOR FUTURE USE	(Worksheet A In 29.C & In 30.C)	425,220	DA		-
231	REGULATORY ASSETS	(Worksheet A In 36. (C))	-	DA		-
232	WORKING CAPITAL	(Note E)				
233	Cash Working Capital	(1/8 * ln 253)	57,983			57,983
234	Transmission Materials & Supplies	(Worksheet C, In 2.(D))	232	TP	1.00000	232
235	A&G Materials & Supplies	(Worksheet C, In 3.(D))	3,123	W/S	0.13137	410
236	Stores Expense	(Worksheet C, In 4.(D))	-	GP(h)	0.16242	-
237	Prepayments (Account 165) - Labor Allocated	(Worksheet C, In 6.G)	5,767,913	W/S	0.13137	757,755
238	Prepayments (Account 165) - Gross Plant	(Worksheet C, In 6.F)	147,105	GP(h)	0.16242	23,893
239	Prepayments (Account 165) - Transmission Only	(Worksheet C, In 6.E)	-	DA	1.00000	-
240	Prepayments (Account 165) - Unallocable	(Worksheet C, In 6.D)	(3,499,352)	NA	0.00000	_
241	TOTAL WORKING CAPITAL	(sum Ins 233 to 240)	2,477,004			840,273
242	IPP CONTRIBUTIONS FOR CONSTRUCTION	(Note F) (Worksheet D, In 7.B)	-	DA	1.00000	-
		, , ,				
243	RATE BASE (sum Ins 222, 229, 230, 231, 241, 242)		68,773,687			9,440,647

KINGSPORT POWER COMPANY

(1) (2) (3)

	(/	()	,		,	,
	EXPENSE, TAXES, RETURN & REVENUE REQUIREMENTS CALCULATION	Data Sources (See "General Notes")	TO Total	Alloc	cator_	Total <u>Transmission</u>
Line						
No.	OPERATION & MAINTENANCE EXPENSE					
244	Production	321.80.b	124,517,930			
245	Distribution	322.156.b	5,354,724			
246	Customer Related Expense	322 & 323.164,171,178.b	1,611,378			
247	Regional Marketing Expenses	322.131.b				
248	Transmission	321.112.b	514,322			
249	TOTAL O&M EXPENSES	(sum Ins 244 to 248)	131,998,354			
250	Less: Total Account 561	(Note G) (Worksheet F, In 14.C)	50,457			
251	Less: Account 565	(Note H) 321.96.b	- ·			
252	Less: Regulatory Deferrals & Amortizations	(Note I) (Worksheet F, In 4.C)	<u> </u>			
253	Total O&M Allocable to Transmission	(Ins 248 - 250 - 251 - 252)	463,865	TP	1.00000	463,865
254	Administrative and General	323.197.b (Note J)	2,534,881			
255	Less: Acct. 924, Property Insurance	323.185.b	195,760			
256	Acct. 9260039 PBOP Expense	PBOP Worksheet O Line 9 & 10, (Note K)	247,734			
257	Acct. 9260057 PBOP Medicare Subsidy	PBOP Worksheet O Line 11, (Note K)	-			
258	PBOP Expense Billed From AEPSC	PBOP Worksheet O Line 13, (Note K)	30,141			
259	Acct. 928, Reg. Com. Exp.	323.189.b	37			
260	Acct. 930.1, Gen. Advert. Exp.	323.191.b	3,024			
261	Acct. 930.2, Misc. Gen. Exp.	323.192.b	185,103			
262	Balance of A & G	(In 254 - sum In 255 to In 261)	1,873,082	W/S	0.13137	246,075
263		(In 255)	195,760	GP(h)	0.16242	31,795
	Plus: Acct. 924, Property Insurance		195,760			31,795
264	Acct. 928 - Transmission Specific	Worksheet F In 18.(E) (Note L)	-	TP	1.00000	-
265	Acct 930.1 - Only safety related ads -Direct	Worksheet F In 26.(E) (Note L)	-	TP	1.00000	-
266	Acct 930.2 - Misc Gen. Exp Trans	Worksheet F In 33.(E) (Note L)	172,732	DA	1.00000	172,732
267	Settlement Approved PBOP Recovery	PBOP Worksheet O, Col. C, Line 5, (Note M)	326,862	W/S	0.13137	42,941
268	A & G Subtotal	(sum Ins 262 to 267)	2,568,436			493,543
269	O & M EXPENSE SUBTOTAL	(In 253 + In 268)	3,032,301			957,408
270	Plus: TEA Settlement in Account 565	Company Records (Note H)	-	DA	1.00000	-
271	Plus: Transmission Lease Payments To Affiliates in A	· · · · · · · · · · · · · · · · · · ·	-	DA	1.00000	-
272	TOTAL O & M EXPENSE	(ln 269 + ln 270 + ln 271)	3,032,301			957,408
		(= 5 5 % = 5 5 % = 5 7)	2,22_,22			
273	DEPRECIATION AND AMORTIZATION EXPENSE					
274	Production	336.2-6.f	-	NA	0.00000	-
275	Distribution	336.8.f	3,905,071	NA	0.00000	_
276	Transmission	336.7.f	533,521	TP1	1.00000	533,521
	Plus: Transmission Plant-in-Service Additions (Works		N/A		1.00000	N/A
277	· ·	,		NA //O	0.40407	
278	General	336.10.f	100,853	W/S	0.13137	13,249
279	Intangible	336.1.f	23,439	W/S	0.13137	3,079
280	TOTAL DEPRECIATION AND AMORTIZATION	(Ln 274+275+	4,562,884			549,850
		276+277+278+279)				
281	TAXES OTHER THAN INCOME	(Note N)				
282	Labor Related					
283	Payroll	Worksheet H In 21.(D)	151,897	W/S	0.13137	19,955
284	Plant Related					
285	Property	Worksheet H In 21.(C) & In 35.(C)	914,068	DA		131,791
286	Gross Receipts/Sales & Use	Worksheet H In 21.(F)	3,847,999	NA	0.00000	-
287	Other	Worksheet H In 21.(E)	404,905	GP(h)	0.16242	65,765
288	TOTAL OTHER TAXES	(sum Ins 283 to 287)	5,318,869	- ()		217,511
		(00)	2,213,333			,•
289	INCOME TAXES	(Note O)				
290	T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =	(11010-0)	39.20%			
	, , , , , , , , , , , , , , , , , , , ,		51.06%			
291	EIT=(T/(1-T)) * (1-(WCLTD/WACC)) =		31.00%			
292	where WCLTD=(In 327) and WACC = (In 330)					
293	and FIT, SIT & p are as given in Note O.					
294	GRCF=1 / (1 - T) = (from In 290)		1.6447			
295	Amortized Investment Tax Credit (enter negative)	(FF1 p.114, ln 19.c)	-			
.	T 0 1 1 2	(1. 004 # / 555)				,
296	Income Tax Calculation	(In 291 * In 299)	3,054,915			419,352
297	ITC adjustment	(In 294 * In 295)	<u> </u>	NP(h)	0.14393	
298	TOTAL INCOME TAXES	(sum Ins 296 to 297)	3,054,915			419,352
299	RETURN ON RATE BASE (Rate Base*WACC)	(In 243 * In 330)	5,982,974			821,290
	NITED FOR CALLED AGAINST THE STATE OF THE ST					
300	INTEREST ON IPP CONTRIBUTION FOR CONST. (Not	e F) (Worksheet D, In 2.(B))	-	DA	1.00000	-
00:	(Oning) / Large and Only of Dividing the Control of	Madrahaat N. Ind. Oak (ITV 0.713)				
301	(Gains) / Losses on Sales of Plant Held for Future Use (\	vorksneet N, In 4, Cols. ((F) & (H))	-			-
200	Toy Impact on Not Loss //Osis) on Oslan of Disate Line 1	or Futuro I loo (lo 204 * lo204)				
302	Tax Impact on Net Loss / (Gain) on Sales of Plant Held to	or nuture use (in 301 " in291)	-			-
303	TOTAL REVENUE REQUIREMENT		21,951,943			2,965,411
505	(sum lns 272 280 288 298 299 300 301 302)		<u> </u>			۷,۶۵۵,411

(sum lns 272, 280, 288, 298, 299, 300, 301, 302)

KINGSPORT POWER COMPANY

SUPPORTING CALCULATIONS

In No. 304 305 306 307	TRANSMISSION PLANT INCLUDED IN PJM TARIFF Total transmission plant Less transmission plant excluded from PJM Tariff (Note Less transmission plant included in OATT Ancillary Service Transmission plant included in PJM Tariff Percent of transmission plant in PJM Tariff	•) (Note Q)					22,330,531 - 22,330,531 1.00000
				Payroll Billed from				
309	WAGES & SALARY ALLOCATOR (W/S)	(Note R)	Direct Payroll	AEP Service Corp.	Total			
310	Production	354.20.b	0	0	-	NA	0.00000	-
311	Transmission	354.21.b	230,280	104,609	334,889	TP	1.00000	334,889
312	Regional Market Expenses	354.22.b	0	0	-	NA	0.00000	-
313	Distribution	354.23.b	1,270,337	257,864	1,528,201	NA	0.00000	-
314	Other (Excludes A&G)	354.24,25,26.b	278,930	407,103	686,033	NA	0.00000	-
315	Total	(sum Ins 310 to 314)	1,779,547	769,576	2,549,123			334,889
316	Transmission related amount						W/S=	0.13137
317	WEIGHTED AVERAGE COST OF CAPITAL (WACC)							¢
	VICIOITIED / VICIOIOE GOOT OF G/ VI TI/LE (VI/VOO)							Ψ
	•	(Worksheet L. In. 35, col. (D))						904.000
318	Long Term Interest Preferred Dividends	(Worksheet L, In. 35, col. (D)) (Worksheet L, In. 40, col. (D))						904,000 -
	Long Term Interest	(Worksheet L, In. 35, col. (D)) (Worksheet L, In. 40, col. (D))						904,000 -
318 319	Long Term Interest Preferred Dividends							904,000 - 29,956,296
318 319 320	Long Term Interest Preferred Dividends <u>Development of Common Stock:</u>	(Worksheet L, In. 40, col. (D))						-
318 319 320 321	Long Term Interest Preferred Dividends <u>Development of Common Stock:</u> Proprietary Capital	(Worksheet L, In. 40, col. (D)) (FF1 p 112, Ln 16.c)						-
318 319 320 321 322	Long Term Interest Preferred Dividends <u>Development of Common Stock:</u> Proprietary Capital Less: Preferred Stock	(Worksheet L, In. 40, col. (D)) (FF1 p 112, Ln 16.c) (FF1 p 112, Ln 3.c)						-
318 319 320 321 322 323	Long Term Interest Preferred Dividends <u>Development of Common Stock:</u> Proprietary Capital Less: Preferred Stock Less: Account 216.1	(Worksheet L, In. 40, col. (D)) (FF1 p 112, Ln 16.c) (FF1 p 112, Ln 3.c) (FF1 p 112, Ln 12.c)	4)					29,956,296 - -
318 319 320 321 322 323 324 325	Long Term Interest Preferred Dividends <u>Development of Common Stock:</u> Proprietary Capital Less: Preferred Stock Less: Account 216.1 Less: Account 219	(Worksheet L, In. 40, col. (D)) (FF1 p 112, Ln 16.c) (FF1 p 112, Ln 3.c) (FF1 p 112, Ln 12.c) (FF1 p 112, Ln 15.c)	4)	Φ.	0/		Cost	29,956,296 - - - 916 29,955,380
318 319 320 321 322 323 324 325	Long Term Interest Preferred Dividends <u>Development of Common Stock:</u> Proprietary Capital Less: Preferred Stock Less: Account 216.1 Less: Account 219 Common Stock	(Worksheet L, In. 40, col. (D)) (FF1 p 112, Ln 16.c) (FF1 p 112, Ln 3.c) (FF1 p 112, Ln 12.c) (FF1 p 112, Ln 15.c)	4)	\$	%		(Note S)	29,956,296 - - 916 29,955,380 Weighted
318 319 320 321 322 323 324 325 326 327	Long Term Interest Preferred Dividends Development of Common Stock: Proprietary Capital Less: Preferred Stock Less: Account 216.1 Less: Account 219 Common Stock Long Term Debt (Note T) Worksheet L, In 35, col. (B))	(Worksheet L, In. 40, col. (D)) (FF1 p 112, Ln 16.c) (FF1 p 112, Ln 3.c) (FF1 p 112, Ln 12.c) (FF1 p 112, Ln 15.c)	4)	\$ 20,000,000	40.04%			29,956,296 - - 916 29,955,380 Weighted 0.0181
318 319 320 321 322 323 324 325 326 327 328	Long Term Interest Preferred Dividends Development of Common Stock: Proprietary Capital Less: Preferred Stock Less: Account 216.1 Less: Account 219 Common Stock Long Term Debt (Note T) Worksheet L, In 35, col. (B)) Preferred Stock (In 322)	(Worksheet L, In. 40, col. (D)) (FF1 p 112, Ln 16.c) (FF1 p 112, Ln 3.c) (FF1 p 112, Ln 12.c) (FF1 p 112, Ln 15.c)	4)	20,000,000	40.04% 0.00%		(Note S) 0.0452 -	29,956,296 - - 916 29,955,380 Weighted 0.0181 0.0000
318 319 320 321 322 323 324 325 326 327	Long Term Interest Preferred Dividends Development of Common Stock: Proprietary Capital Less: Preferred Stock Less: Account 216.1 Less: Account 219 Common Stock Long Term Debt (Note T) Worksheet L, In 35, col. (B))	(Worksheet L, In. 40, col. (D)) (FF1 p 112, Ln 16.c) (FF1 p 112, Ln 3.c) (FF1 p 112, Ln 12.c) (FF1 p 112, Ln 15.c)	4)	· · · · · · · · · · · · · · · · · · ·	40.04%		(Note S)	29,956,296 - - 916 29,955,380 Weighted 0.0181

KINGSPORT POWER COMPANY

<u>Letter</u> <u>Notes</u>

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

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

See Worksheet E for details.

- B The annual and monthly net plant carrying charges on page 1 are used to compute the revenue requirement for RTEP sponsored upgrades or those projects receiving approved incentive-ROE's.
- C Transmission Plant balances in this study are historic as of December 31, 2012.
- The total-company balances shown for Accounts 281, 282, 283, 190 only reflect ADIT that relates to utility operations. The balance of Account 255 is reduced by prior flow throughs and is completely excluded if the utility chose to utilize amortization of tax credits against FIT expense. An exception to this is pre-1971 ITC balances, which are required to be taken as an offset to rate base. Account 281 is not allocated. In compliance with FERC Rulemaking RM02-7-000, Asset Retirement Obligation deferrals have been removed from ratebase. Transmission ADIT allocations are shown on WS B.

The company will not include the ADIT portion of deferred hedge gains and losses in rate base.

- E Cash Working Capital assigned to transmission is one-eighth of O&M allocated to transmission, as shown on line 253. It excludes:
 - 1) Load Scheduling & Dispatch Charges in account 561 that are collected in the OATT Ancilliary Services Revenue, as shown on line 250.
 - 2) AEP transmission equalization transfers, as shown on line 251
 - 3) The impact of state regulatory deferrals and amortizations, as shown on line 252
 - 4) All A&G Expenses, as shown on line 268.
- F Consistent with Paragraph 657 of Order 2003-A, the amount on line 242 is equal to the balance of IPP System Upgrade Credits owed to transmission customers that made contributions toward the construction of System upgrades, and includes accrued interest and unreturned balance of contributions. The annual interest expense is included on line 300.
- Removes from the cost of service the Load Scheduling and Dispatch expenses booked to accounts 561.1 through 561.8. Expenses recorded in these accounts, with the exception of 561.4 & 561.8 (lines 180 & 181 above) are recovered in Schedule 1A, OATT ancillary services rates. See Worksheet F, lines 5 through 14, for descriptions and the Form 1 Source of these accounts' balances.
- Removes cost of transmission service provided by others to determine the basis of cash working capital on line 253. To the extent such service is incurred to provide the PJM service at issue, e.g. transmission equalization agreement, such costs are added back on lines 270 and 271 to determine the total O&M collected in the formula. The amounts on lines 270 and 271 are also excluded in the calculation of the FCR percentage calculated on lines 170 through 176.

The addbacks on lines 270 and 271 of activity recorded in 565 represents inter-company sales or purchases of transmission capacity necessary to meet each AEP company's transmission load relative to their available transmission capacity.

The company records referenced on lines 270 and 271 is the KINGSPORT POWER COMPANY general ledger.

- I Removes the impact of state regulatory deferrals or their amortization from O&M expense.
 - General Plant and Administrative & General expenses, other than in accounts 924, 928, and 930, will be functionalized based on the Wages & Salaries "W/S" allocator. The allocation basis for accounts 924, 928 and 930 are separately presented in the formula. A change in the allocation method for an account must be approved via a 205 filing with the FERC.
- K These deductions on lines 256 through 258 are to remove from the cost of service the expenses recorded by the company for Postemployment Benefits Other than Pensions (PBOP). See Note M below for the recoverable PBOP expense.
- Expenses reported for these A&G accounts will be included in the cost of service only to the extent they are directly assignable to transmission service. Worksheet F allocates these expense items. Acct 928 Includes Regulatory Commission expenses itemized in FERC Form-1 at page 351, column H. FERC Assessment Fees and Annual Charges shall not be allocated to transmission. Only safety-related and educational advertising costs in Account 930.1 are included in the TCOS. Account 930.2 includes the expenses incurred by the transmission function for Associated Business Development revenues given as a credit to the TCOS on Worksheet E.
- M See note K above. Per the settlement in Docket ER08-1329, recoverable PBOP expense is based on an annual total for the operating companies that is ratioed to them based on the total of actual annual PBOP costs, including charges from the AEP Service Corportation. The calculation of the recoverable amount for each company is shown on Worksheet O, and the process for updating the annual total is documented on Attachment F, Allowable PBOP Expense Formula.
- N Includes only FICA, unemployment, highway, property and other assessments charged in the current year. Gross receipts, sales & use and taxes related to income are excluded.
- The currently effective income tax rate, where FIT is the Federal income tax rate; SIT is the State income tax rate, and p = the percentage of federal income tax deductible for state income taxes. See Worksheet G for the development of the Company's composite SIT.

 A utility that elected to utilize amortization of tax credits against taxable income, rather than book tax credits to Account No. 255 and reduce rate base, must reduce its income tax expense by the amount of the Amortized Investment Tax Credit (Form 1, 266.8.f)

(In 295) multiplied by (1/1-T) . If the applicable tax rates are zero enter 0.

Inputs Required:

SIT = 35.00%

SIT = 6.46%

p = 0.00%

(State Income Tax Rate or Composite SIT. Worksheet G))

(percent of federal income tax deductible for state purposes)

- P Removes plant excluded from the OATT because it does not meet the PJM's definition of Transmission Facilities or is otherwise ineligible to be recovered under the OATT.
- Q Removes transmission plant (e.g. step-up transformers) included in the development of OATT ancillary service rates and not already removed for reasons indicated in Note P.
- R Includes functional wages & salaries billed by AEP Service Corporation for support of the operating company.
- S Long Term Debt cost rate = long-term interest (ln 318) / long term debt (ln 327). Preferred Stock cost rate = preferred dividends (ln 319) / preferred outstanding (ln 328). Common Stock cost rate (ROE) = 11.49%, the rate accepted by FERC in Docket No. ER08-1329. It includes an additional 50 basis points for remaining a member of the PJM RTO.

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

- T This note only applies to Indiana Michigan Power Company.
- U This note only applies to the true-up template.

KINGSPORT POWER COMPANY

Line No.						Tra	ansmission Amount
1	REVENUE REQUIREMENT (w/o incentives)	(In 138)	-				\$2,885,916
2	REVENUE CREDITS	(Note A) (Worksheet E)	Total 306,055	DA All	ocator 1.00000	\$	306,055
3	REVENUE REQUIREMENT For All Company Facilities	(In 1 less In 2)				\$	2,579,861
	The Carrying Charge Calculations on lines 6 to 11 belonsmission Enhancement Charges. The total non-incenti		-				
4	Revenue Requirement for PJM Schedule 12 Facilities (w	/o incentives) (Worksheet K)	-	DA	1.00000	\$	-
5	NET PLANT CARRYING CHARGE w/o intra-AEP charge	s or credits or ROE incentives (Note B)					
6	Annual Rate	((ln 1 - ln 105 - ln 106)/ ln 48 x 100)					26.48%
7	Monthly Rate	(In 6 / 12)					2.21%
8	NET PLANT CARRYING CHARGE ON LINE 6, w/o depr	reciation or ROE incentives (Note B)					
9	Annual Rate	((ln 1 - ln 105 - ln 106 - ln 111) / ln 48 x 100)					21.58%
10	NET PLANT CARRYING CHARGE ON LINE 9, w/o Retu	rn, income taxes or ROE incentives (Note B)					
11	Annual Rate	((ln 1 - ln 105 - ln 106 - ln 111 - ln 133 - ln 13	4) / ln 48 x 100)				10.91%
12	ADDITIONAL REVENUE REQUIREMENT for projects w/	incentive ROE's (Note B) (Worksheet K)					-
13		REVENUE REQUIREMENT FOR SCH	HEDULE 1A CHARGES				
14	Total Load Dispatch & Scheduling (Account 561)	Line 85 Below					50,457
15	Less: Load Dispatch - Scheduling, System Control and I						1,263
16	Less: Load Dispatch - Reliability, Planning & Standards						-
17	Total 561 Internally Developed Costs	(Line 14 - Line 15 - Line 16)					49,194
	·	,					,

KINGSPORT POWER COMPANY

		KINGGI OKT I OV	VVER COMI / (IV)			
	(1)	(2)	(3)		(4)	(5)
	(1)	(2)	(0)		(')	(0)
		Data Sources				Total
	RATE BASE CALCULATION	(See "General Notes")	TO Total	Alle	ocator	Transmission
Line		<u>,</u>	NOTE C			
No.	GROSS PLANT IN SERVICE					
18	Production	(Worksheet A In 1.E)	-	NA	0.00000	-
19	Less: Production ARO (Enter Negative)	(Worksheet A In 2.E)	-	NA	0.00000	-
20	Transmission	(Worksheet A In 3.C & Ln 142)	21,297,488	DA		21,297,488
21	Less: Transmission ARO (Enter Negative)	(Worksheet A In 4.C& Ln 143)	<u>-</u> _	TP	1.00000	-
22	Plus: Transmission Plant-in-Service Additions (Work	(sheet I)	N/A	NA	0.00000	N/A
23	Plus: Additional Trans Plant on Transferred Assets (Worksheet I)	N/A	NA	0.00000	N/A
24	Distribution	(Worksheet A In 5.E)	112,183,057	NA	0.00000	-
25	Less: Distribution ARO (Enter Negative)	(Worksheet A In 6.E)	· · · · · · · · · · · · · · · · · · ·	NA	0.00000	-
26	General Plant	(Worksheet A In 7.E)	2,505,217	W/S	0.13137	329,121
27	Less: General Plant ARO (Enter Negative)	(Worksheet A In 8.E)	-	W/S	0.13137	-
28	Intangible Plant	(Worksheet A In 9.E)	1,231,204	W/S	0.13137	161,748
29	TOTAL GROSS PLANT	(sum Ins 18 to 28)	137,216,965	GP(h)=	0.15879	21,788,357
		,		GTD=	0.00000	
30	ACCUMULATED DEPRECIATION AND AMORTIZATION	DN				
31	Production	(Worksheet A In 12.E)	-	NA	0.00000	-
32	Less: Production ARO (Enter Negative)	(Worksheet A In 13.E)	-	NA	0.00000	_
33	Transmission	(Worksheet A In 14.E & 28.E)	10,398,159	TP1=	1.00000	10,398,159
34	Less: Transmission ARO (Enter Negative)	(Worksheet A In 15.E)	-	TP1=	1.00000	-
35	Plus: Transmission Plant-in-Service Additions (Work	,	N/A	DA	1.00000	N/A
36	Plus: Additional Projected Deprec on Transferred As	•	N/A	DA	1.00000	N/A
30 37	Plus: Additional Transmission Depreciation for 2013	,	N/A	TP1		N/A
	•	·	N/A N/A	W/S	1.00000	N/A
38	Plus: Additional General & Intangible Depreciation for	,			0.13137	
39	Plus: Additional Accum Deprec on Transferred Asse	· · · · · · · · · · · · · · · · · · ·	N/A	DA	1.00000	N/A
40	Distribution	(Worksheet A In 16.E)	43,579,293	NA	0.00000	-
41	Less: Distribution ARO (Enter Negative)	(Worksheet A In 17.E)	-	NA W/O	0.00000	- 04 570
42	General Plant	(Worksheet A In 18.E)	697,030	W/S	0.13137	91,572
43	Less: General Plant ARO (Enter Negative)	(Worksheet A In 19.E)	-	W/S	0.13137	400,000
44	Intangible Plant	(Worksheet A In 20.E)	1,494,729	W/S	0.13137	196,369
45	TOTAL ACCUMULATED DEPRECIATION	(sum Ins 31 to 44)	56,169,210			10,686,099
46	NET PLANT IN SERVICE	(1, 1, 1, 1, 1, 1, 1, 1, 1, 1, 1, 1, 1, 1				
47	Production	(ln 18 + ln 19 - ln 31 - ln 32)	-			-
48	Transmission	(ln 20 + ln 21 - ln 33 - ln 34)	10,899,330			10,899,330
49	Plus: Transmission Plant-in-Service Additions (In 22	,	N/A			N/A
50	Plus: Additional Trans Plant on Transferred Assets	· · · · · · · · · · · · · · · · · · ·	N/A			N/A
51	Plus: Additional Transmission Depreciation for 2013	•	N/A			N/A
52	Plus: Additional General & Intangible Depreciation for		N/A			N/A
53	Plus: Additional Accum Deprec on Transferred Asse	ets (Worksheet I) (-In 39)	N/A			N/A
54	Distribution	(ln 24 + ln 25 - ln 40 - ln 41)	68,603,764			-
55	General Plant	(In 26 + In 27 - In 42 - In 43)	1,808,188			237,549
56	Intangible Plant	(In 28 - In 44)	(263,526)			(34,620)
57	TOTAL NET PLANT IN SERVICE	(sum Ins 47 to 56)	81,047,756	NP(h)=	0.13698	11,102,258
58	DEFERRED TAX ADJUSTMENTS TO RATE BASE	(Note D)				
59	Account No. 281.1 (enter negative)	(Worksheet B, In 2 & In 5.E)	-	NA		-
60	Account No. 282.1 (enter negative)	(Worksheet B, In 7 & In 10.E)	(15,951,204)	DA		(2,914,009)
61	Account No. 283.1 (enter negative)	(Worksheet B, In 12 & In 15.E)	(1,353,108)	DA		(183,484)
62	Account No. 190.1	(Worksheet B, In 17 & In 20.E)	718,901	DA		68,464
63	Account No. 255 (enter negative)	(Worksheet B, In 24 & In 25.E)	(81,281)	DA		(17,244)
64	TOTAL ADJUSTMENTS	(sum Ins 59 to 63)	(16,666,692)			(3,046,272)
		,	, , ,			(, , , ,
65	PLANT HELD FOR FUTURE USE	(Worksheet A In 29.E & In 30.E)	336,096	DA		-
		,				
66	REGULATORY ASSETS	(Worksheet A In 36. (E))	-	DA		-
		(//				
67	WORKING CAPITAL	(Note E)				
68	Cash Working Capital	(1/8 * In 88)	57,983			57,983
69	Transmission Materials & Supplies	(Worksheet C, In 2.F)	646	TP	1.00000	646
70	A&G Materials & Supplies	(Worksheet C, In 3.F)	1,617	W/S	0.13137	212
71	Stores Expense	(Worksheet C, In 4.(D))	-	GP(h)	0.15879	-
72	Prepayments (Account 165) - Labor Allocated	(Worksheet C, In 8.G)	5,594,327	W/S	0.13137	734,950
73	Prepayments (Account 165) - Gross Plant	(Worksheet C, In 8.F)	139,831	GP(h)	0.15879	22,203
74	Prepayments (Account 165) - Transmission Only	(Worksheet C, In 8.E)	-	DA	1.00000	-
75	Prepayments (Account 165) - Unallocable	(Worksheet C, In 8.D)	(3,474,365)	NA	0.00000	-
76	TOTAL WORKING CAPITAL	(sum Ins 68 to 75)	2,320,038	1 4/ 1	0.0000	815,995
, 0	. STALL TOTAL OF THAT	(53 55 55 75)	2,020,000			010,000
77	IPP CONTRIBUTIONS FOR CONSTRUCTION	(Note F) (Worksheet D, In 8 (B))	-	DA	1.00000	_
		(

67,037,197

8,871,981

RATE BASE (sum Ins 57, 64, 65, 66, 76, 77)

78

KINGSPORT POWER COMPANY

(1) (2) (3) (4) (5)

Line	EXPENSE, TAXES, RETURN & REVENUE REQUIREMENTS CALCULATION	Data Sources (See "General Notes")	TO Total	Allo	ocator_	Total <u>Transmission</u>
No.	OPERATION & MAINTENANCE EXPENSE					
79	Production	321.80.b	124,517,930			
80	Distribution	322.156.b	5,354,724			
81	Customer Related Expense	322.164,171,178.b	1,611,378			
82	Regional Marketing Expenses	322.131.b	-			
83	Transmission	321.112.b	514,322			
84	TOTAL O&M EXPENSES	(sum Ins 79 to 83)	131,998,354			
85	Less: Total Account 561	(Note G) (Worksheet F, In 14.C)	50,457			
86	Less: Account 565	(Note H) 321.96.b	-			
87	Less: Regulatory Deferrals & Amortizations	(Note I) (Worksheet F, In 4.C)	<u>_</u>			
88	Total O&M Allocable to Transmission	(Ins 83 - 85 - 86 - 87)	463,865	TP	1.00000	463,865
00	Total Oalvi Allocable to Transmission	(1115 03 - 03 - 00 - 07)	403,003	IF	1.00000	403,003
89	Administrative and General	323.197.b (Note J)	2,534,881			
	Less: Acct. 924, Property Insurance	323.185.b				
90			195,760			
91	Acct. 9260039 PBOP Expense	PBOP Worksheet O Line 9 & 10, (Note K)	247,734			
92	Acct. 9260057 PBOP Medicare Subsidy	PBOP Worksheet O Line 11, (Note K)	-			
93	PBOP Expense Billed From AEPSC	PBOP Worksheet O Line 13, (Note K)	30,141			
94	Acct. 928, Reg. Com. Exp.	323.189.b	37			
95	Acct. 930.1, Gen. Advert. Exp.	323.191.b	3,024			
96	Acct. 930.2, Misc. Gen. Exp.	323.192.b	185,103			
97	Balance of A & G	(In 89 - sum In 90 to In 96)	1,873,082	W/S	0.13137	246,075
98	Plus: Acct. 924, Property Insurance	(In 90)	195,760	GP(h)	0.15879	31,084
99	Acct. 928 - Transmission Specific	Worksheet F In 18.(E) (Note L)	-	TP	1.00000	-
100	Acct 930.1 - Only safety related ads -Direct	Worksheet F In 26.(E) (Note L)	-	TP	1.00000	-
101	Acct 930.2 - Misc Gen. Exp Trans	Worksheet F In 33.(E) (Note L)	172,732	DA	1.00000	172,732
102	Settlement Approved PBOP Recovery	PBOP Worksheet O, Col. C, Line 5, (Note M)	326,862	W/S	0.13137	42,941
103	A & G Subtotal	(sum Ins 97 to 102)	2,568,436		•	492,832
100	7. a o capital	(54111116 57 15 152)	2,000,100			102,002
104	O & M EXPENSE SUBTOTAL	(ln 88 + ln 103)	3,032,301		•	956,697
105	Plus: TEA Settlement in Account 565	Company Records (Note H)	3,032,301	DA	1.00000	930,097
106	Plus: Transmission Lease Payments To Affiliates in A		-	DA	1.00000	-
	•		2 222 224	DA	1.00000	050.007
107	TOTAL O & M EXPENSE	(In 104 + In 105 + In 106)	3,032,301			956,697
400	DEDDEOLATION AND AMODITATION EVENUE					
108	DEPRECIATION AND AMORTIZATION EXPENSE					
109	Production	336.2-6.f	-	NA	0.00000	-
110	Distribution	336.8.f	3,905,071	NA	0.00000	-
111	Transmission	336.7.f	533,521	TP1	1.00000	533,521
112	Plus: Transmission Plant-in-Service Additions (Works	•	N/A			N/A
113	General	336.10.f	100,853	W/S	0.13137	13,249
114	Intangible	336.1.f	23,439	W/S	0.13137	3,079
115	TOTAL DEPRECIATION AND AMORTIZATION	(Ln 109+110+	4,562,884		•	549,850
		111+112+113+114)				
116	TAXES OTHER THAN INCOME	(Note N)				
117	Labor Related	,				
118	Payroll	Worksheet H In 21.(D)	151,897	W/S	0.13137	19,955
119	Plant Related	()	•			,
120	Property	Worksheet H In 21.(C) & In 35.(C)	914,068	DA		131,791
121	Gross Receipts/Sales & Use	Worksheet H In 21.(F)	3,847,999	NA	0.00000	-
122	Other	Worksheet H In 21.(E)	404,905	GP(h)	0.15879	64,294
123	TOTAL OTHER TAXES	(sum Ins 118 to 122)	5,318,869	O 1 (11)	0.10070	216,040
120	IOIAL OHILK IAMED	(541111115 1 10 to 122)	5,510,003			£10,0 4 0
124	INCOME TAXES	(Note O)				
		(11016 0)	20.200/			
125	T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =		39.20%			
126	EIT=(T/(1-T)) * (1-(WCLTD/WACC)) =		50.97%			
127	where WCLTD=(In 162) and WACC = (In 165)					
128	and FIT, SIT & p are as given in Note O.					
129	GRCF=1 / (1 - T) = (from ln 125)		1.6447			
130	Amortized Investment Tax Credit (enter negative)	(FF1 p.114, ln 19.c)	-			
131	Income Tax Calculation	(In 126 * In 134)	2,967,732			392,762
132	ITC adjustment	(ln 129 * ln 130)	<u> </u>	NP(h)	0.13698	<u> </u>
133	TOTAL INCOME TAXES	(sum lns 131 to 132)	2,967,732	• •	•	392,762
		,				, -
134	RETURN ON RATE BASE (Rate Base*WACC)	(In 78 * In 165)	5,822,453			770,568
= -	- (=	,	, ,			,,,,,,,
135	INTEREST ON IPP CONTRIBUTION FOR CONST. (Note	e F) (Worksheet D. In 2.(B))	-	DA	1.00000	_
100		, (··· -··· -· , ··· -· (-))		2, (1.00000	
136	(Gains) / Losses on Sales of Plant Held for Future Use (V	Vorksheet N In 4 Cals ((F) & (H))	_			
130	(Value) / Losses on Jaies of Flant Held for Future USE (V	volkoneet iv, iii $+$, cois. ((i $j \propto (\Box j)$)	-			-
107	Tay Impact on Not Loss / (Cain) on Calas of Diant Hald f	or Futuro I Iso /In 126 * In126\				
137	Tax Impact on Net Loss / (Gain) on Sales of Plant Held f	or r uture 056 (III 150 - III120)	-			-
400	TOTAL DEVENUE DECLUDEMENT	<u>-</u> -	04 704 000		•	0.005.010
138	TOTAL REVENUE REQUIREMENT	<u> </u>	21,704,239			2,885,916
	(sum Ins 107, 115, 123, 133, 134, 135)					

KINGSPORT POWER COMPANY

SUPPORTING CALCULATIONS

ln								
No.	TRANSMISSION PLANT INCLUDED IN PJM TARIFF							
139	Total transmission plant	(In 20)						21,297,488
140	Less transmission plant excluded from PJM Tariff (Note	e P)						-
141	Less transmission plant included in OATT Ancillary Services	vices (Worksheet A, In 23, Col	I. (C)) (Note Q)					-
142	Transmission plant included in PJM Tariff	(ln 139 - ln 140 - ln 141)						21,297,488
143	Percent of transmission plant in PJM Tariff	(In 142 / In 139)					TP=	1.00000
				Payroll Billed from				
144	WAGES & SALARY ALLOCATOR (W/S)	(Note R)	Direct Payroll	AEP Service Corp.	Total			
145	Production	354.20.b	0	0	-	NA	0.00000	-
146	Transmission	354.21.b	230,280	104,609	334,889	TP	1.00000	334,889
147	Regional Market Expenses	354.22.b	0	0	-	NA	0.00000	-
148	Distribution	354.23.b	1,270,337	257,864	1,528,201	NA	0.00000	-
149	Other (Excludes A&G)	354.24,25,26.b	278,930	407,103	686,033	NA	0.00000	-
150	Total	(sum Ins 145 to 149)	1,779,547	769,576	2,549,123			334,889
151	Transmission related amount						W/S=	0.13137
152	WEIGHTED AVERAGE COST OF CAPITAL (WACC)							\$
153	Long Term Interest	(Worksheet M, In. 21, col. (E	=))					904,000
154	Preferred Dividends	(Worksheet M, In. 56, col. (E	,,					-
155	Development of Common Stock:	(**************************************	-//					Average
156	Proprietary Capital	(Worksheet M, In. 1, col. (E))					29,703,242
157	Less: Preferred Stock	(Worksheet M, In. 2, col. (E)	•					20,700,242
158	Less: Account 216.1	(Worksheet M, In. 3, col. (E)	•					-
159	Less: Account 219	(Worksheet M, In. 4, col. (E)	,					(918)
160	Common Stock	(In 156 - In 157 - In 158 - In						29,704,160
100	Common Glock	(111 100 111 107 111 100 111	100)	Capital Structure	Weighting		Cost	25,704,100
161		Average \$		Actual	Cap Limit		(Note S)	Weighted
162	Long Term Debt (Note T) W/S M, In 11, In 22, col. (E))	20,000,000		40.24%	0.00%		0.0452	0.0182
163	Preferred Stock (In 157)	20,000,000		0.00%	0.00%		J.J.J.Z	0.0000
164	Common Stock (In 160)	29,704,160		59.76%	0.00%		11.49%	0.0687
165	Total (Sum Ins 162 to 164)	49,704,160		00.1070	0.0070		WACC=	0.0869
100	10tal (0alli 110 102 to 10 1)	73,707,100					11700-	0.0009
166	Capital Structure Equity Limit (Note U)	100.0%						

KINGSPORT POWER COMPANY

<u>Notes</u>

<u>Letter</u>

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

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

See Worksheet E for details.

- B The annual and monthly net plant carrying charges on page 1 are used to compute the revenue requirement for RTEP sponsored upgrades or those projects receiving approved incentive-ROE's.
- C Transmission Plant balances in this study reflect the average of the balances at December 31, 2011 and December 31, 2012.
- The total-company balances shown for Accounts 281, 282, 283, 190 only reflect ADIT that relates to utility operations. The balance of Account 255 is reduced by prior flow throughs and is completely excluded if the utility chose to utilize amortization of tax credits against FIT expense. An exception to this is pre-1971 ITC balances, which are required to be taken as an offset to rate base. Account 281 is not allocated. In compliance with FERC Rulemaking RM02-7-000, Asset Retirement Obligation deferrals have been removed from ratebase. Transmission ADIT allocations are shown on WS B.

 The company will not include the ADIT portion of deferred hedge gains and losses in rate base.
- E Cash Working Capital assigned to transmission is one-eighth of O&M allocated to transmission, as shown on line 88. It excludes:
 - 1) Load Scheduling & Dispatch Charges in account 561 that are collected in the OATT Ancilliary Services Revenue, as shown on line 85.
 - 2) AEP transmission equalization transfers, as shown on line 86
 - 3) The impact of state regulatory deferrals and amortizations, as shown on line 87
 - 4) All A&G Expenses, as shown on line 103.
- F Consistent with Paragraph 657 of Order 2003-A, the amount on line 77 is equal to the balance of IPP System Upgrade Credits owed to transmission customers that made contributions toward the construction of System upgrades, and includes accrued interest and unreturned balance of contributions. The annual interest expense is included on line 135.
- Removes from the cost of service the Load Scheduling and Dispatch expenses booked to accounts 561.1 through 561.8. Expenses recorded in these accounts, with the exception of 561.4 & 561.8 (lines 15 & 16 above) are recovered in Schedule 1A, OATT ancillary services rates. See Worksheet F, lines 5 through 14, for descriptions and the Form 1 Source of these accounts' balances.
- Removes cost of transmission service provided by others to determine the basis of cash working capital on line 88. To the extent such service is incurred to provide the PJM service at issue, e.g. transmission equalization agreement, such costs are added back on lines 105 and 106 to determine the total O&M collected in the formula. The amounts on lines 105 and 106 are also excluded in the calculation of the FCR percentage calculated on lines 5 through 11.
 - The addbacks on lines 105 and 106 of activity recorded in 565 represents inter-company sales or purchases of transmission capacity necessary to meet each AEP company's transmission load relative to their available transmission capacity.

The company records referenced on lines 105 and 106 is the KINGSPORT POWER COMPANY general ledger.

- Removes the impact of state regulatory deferrals or their amortization from O&M expense. applicable only for state regulatory purposes.
- J General Plant and Administrative & General expenses, other than in accounts 924, 928, and 930, will be functionalized based on the Wages & Salaries "W/S" allocator. The allocation basis for accounts 924, 928 and 930 are separately presented in the formula. A change in the allocation method for an account must be approved via a 205 filing with the FERC.
- K These deductions on lines 91 through 93 are to remove from the cost of service the expenses recorded by the company for Postemployment Benefits Other than Pensions (PBOP). See Note M below for the recoverable PBOP expense.
- Expenses reported for these A&G accounts will be included in the cost of service only to the extent they are directly assignable to transmission service. Worksheet F allocates these expense items. Acct 928 Includes Regulatory Commission expenses itemized in FERC Form-1 at page 351, column H. FERC Assessment Fees and Annual Charges shall not be allocated to transmission. Only safety-related and educational advertising costs in Account 930.1 are included in the TCOS. Account 930.2 includes the expenses incurred by the transmission function for Associated Business Development revenues given as a credit to the TCOS on Worksheet E.
- M See note K above. Per the settlement in Docket ER08-1329, recoverable PBOP expense is based on an annual total for the operating companies that is ratioed to them based on the total of actual annual PBOP costs, including charges from the AEP Service Corportation. The calculation of the recoverable amount for each company is shown on Worksheet O, and the process for updating the annual total is documented on Attachment F, Allowable PBOP Expense Formula.
- N Includes only FICA, unemployment, highway, property and other assessments charged in the current year. Gross receipts, sales & use and taxes related to income are excluded.
- The currently effective income tax rate, where FIT is the Federal income tax rate; SIT is the State income tax rate, and p = the percentage of federal income tax deductible for state income taxes. See Worksheet G for the development of the Company's composite SIT. A utility that elected to utilize amortization of tax credits against taxable income, rather than book tax credits to Account No. 255 and reduce rate base, must reduce its income tax expense by the amount of the Amortized Investment Tax Credit (Form 1, 266.8.f) (In 130) multiplied by (1/1-T). If the applicable tax rates are zero enter 0.

Inputs Required: FIT = 35.00%

SIT= 6.46% (State Income Tax Rate or Composite SIT. Worksheet G))
p = 0.00% (percent of federal income tax deductible for state purposes)

- P Removes plant excluded from the OATT because it does not meet the PJM's definition of Transmission Facilities or is otherwise ineligible to be recovered under the OATT.
- Q Removes transmission plant (e.g. step-up transformers) included in the development of OATT ancillary service rates and not already removed for reasons indicated in Note P.
- R Includes functional wages & salaries billed by AEP Service Corporation for support of the operating company.
- Long Term Debt cost rate = long-term interest (ln 153) / long term debt (ln 162). Preferred Stock cost rate = preferred dividends (ln 154) / preferred outstanding (ln 163). Common Stock cost rate (ROE) = 11.49%, the rate accepted by FERC in Docket No. ER08-1329. It includes an additional 50 basis points for PJM RTO membership. Interest expense for the true-up WACC is based on actual expenses for the true-up year. The amount of eligible hedging gains or losses included in total interest expense is limited to five basis points of the true-up capital structure. Details and calculations of the true-up weighted average cost of capital are shown on Worksheet M. Eligible Hedging Gains and Losses are defined in the Formula Protocols in the tariff, and on Worksheet M.
- This note only applies to Indiana Michigan Power Company.
- Per Settlement, equity for KINGSPORT POWER COMPANY is limited to 100% of Capital Structure. If the percentage of equity exceeds the cap, the excess is included in weighted percentage of long term debt in the capital structure.

 During the period ended December 31, 2011 the equity cap is in effect. During this period is about a percentage must be approved via a 205 filling with
 - During the period ended December 31, 2011 the equity cap is in effect. During this period, a change in the cap percentage must be approved via a 205 filing with the FERC.

AEP East Companies Cost of Service Formula Rate Using 2012 FF1 Balances Worksheet A Supporting Plant Balances KINGSPORT POWER COMPANY

<u>Line</u>	(A)	(B)	(C)	(D)	(E)
Number	Rate Base Item & Supporting Balance	Source of Data	Balance @ December Ba	<u>alance @ December</u> 31, 2011	Average Balance for 2012
NOTE: Func	tional ARO investment and accumulated depreciation	n balances shown below are included in the total			
	nent Balances				
1	Production Plant In Service	FF1, page 205 Col.(g) & pg. 204 Col. (b), In 46	-	-	-
2	Production Asset Retirement Obligation (ARO)	FF1, page 205&204, Col.(g)&(b), Ins 15,24,34,44	-	-	-
3	Transmission Plant In Service	FF1, page 207 Col.(g) & pg. 206 Col. (b), In 58	22,330,531	20,264,445	21,297,488
4	Transmission Asset Retirement Obligation	FF1, page 207 Col.(g) & pg. 206 Col. (b), In 57	-	-	-
5	Distribution Plant In Service	FF1, page 207 Col.(g) & pg. 206 Col. (b), In 75	114,411,136	109,954,977	112,183,057
6	Distribution Asset Retirement Obligation	FF1, page 207 Col.(g) & pg. 206 Col. (b), In 74	-		-
7	General Plant In Service	FF1, page 207 Col.(g) & pg. 206 Col. (b), In 99	2,558,752	2,451,682	2,505,217
8	General Asset Retirement Obligation	FF1, page 207 Col.(g) & pg. 206 Col. (b), In 98			-
9	Intangible Plant In Service	FF1, page 205 Col.(g) & pg. 204 Col. (b), In 5	1,334,980	1,127,427	1,231,204
10	Total Property Investment Balance	(Sum of Lines: 3, 1, 5, 7, 9)	140,635,399	133,798,531	137,216,965
11	Total ARO Balance (included in total on line 10)	(Sum of Lines: 4, 2, 6, 8)		-	-
Accumulated	Depreciation & Amortization Balances				
12	Production Accumulated Depreciation	FF1, page 219, Ins 20-24, Col. (b)		-	-
13	Production ARO Accumulated Depreciation	Company Records - Note 1	-	-	-
14	Transmission Accumulated Depreciation	FF1, page 219, ln 25, Col. (b)	10,591,842	10,204,475	10,398,159
15	Transmission ARO Accumulated Depreciation	Company Records - Note 1	-	-	-
16	Distribution Accumulated Depreciation	FF1, page 219, In 26, Col. (b)	44,733,167	42,425,418	43,579,293
17	Distribution ARO Accumulated Depreciation	Company Records - Note 1	-	-	-
18	General Accumulated Depreciation	FF1, page 219, ln 28, Col. (b)	732,776	661,283	697,030
19	General ARO Accumulated Depreciation	Company Records - Note 1		-	-
20	Intangible Accumulated Amortization	FF1, page 200, In 21, Col. (b)	1,516,239	1,473,219	1,494,729
21	Total Accumulated Depreciation or Amortization	(Sum of Lines: 14, 12, 16, 18, 20)	57,574,024	54,764,395	56,169,210
22	Total ARO Balance (included in total on line 21)	(Sum of Lines: 15, 13, 17, 19)	-	-	-
Generation S	tep-Up Units				
23	GSU Investment Amount	Company Records - Note 1	-		-
24	GSU Accumulated Depreciation	Company Records - Note 1	-	-	-
25	GSU Net Balance	(Line 23 - Line 24)		-	-
Transmission	n Accumulated Depreciation Net of GSU Accumulated	d Depreciation			
26	Transmission Accumulated Depreciation	(Line 14 Above)	10,591,842	10,204,475	10,398,159
27	Less: GSU Accumulated Depreciation	(Line 24 Above)	-	-	-
28	Subtotal of Transmission Net of GSU	(Line 26 - Line 27)	10,591,842	10,204,475	10,398,159
Plant Held Fo	or Future Use				
29	Plant Held For Future Use	FF1, page 214, In 47, Col. (d)	425,220	246,973	336,096
30	Transmission Plant Held For Future	Company Records - Note 1	-		-
Regulatory A	ssets and Liabilities Approved for Recovery In Rateb Note: Regulatory Assets & Liabilities can only be inclu		C		
31 32	Hote. Regulatory Assets & Liabilities call offly be Inclu	add in ratobase pursuant to a 205 ming with the FERT	J.		-
33 34					- -
35 36	Total Regulatory Deferrals Included in Ratebase				- -
55	. Start Togalatory Doloridio Moradou III Nationalo				

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

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

AEP East Companies Cost of Service Formula Rate Using 2012 FF1 Balances Worksheet B Supporting ADIT and ITC Balances KINGSPORT POWER COMPANY

	(A)	(B)	(C)	(D)	(E)
<u>Line</u> <u>Number</u>	<u>Description</u>	<u>Source</u>	Balance @ December 31, 2012	Balance @ December 31, 2011	Average Balance for 2012
1	Account 281				
2 3 4 5	Year End Utility Deferrals Less: ARO Related Deferrals Less: Other Excluded Deferrals Transmission Related Deferrals	FF1, p. 272 - 273, ln 8, Col. (k) Company Records - Note 1 Company Records - Note 1 Ln 2 - ln 3 - ln 4	-	-	- - -
6	Account 282				
7 8 9 10	Year End Utility Deferrals Less: ARO Related Deferrals Less: Other Excluded Deferrals Transmission Related Deferrals	FF1, p. 274 - 275, In 5, Col. (k) Company Records - Note 1 Company Records - Note 1 Ln 7 - In 8 - In 9	16,710,005 0 13,466,606 3,243,399	15,192,403 0 12,607,785 2,584,618	15,951,204 - 13,037,196 2,914,009
11	Account 283				
12 13 14 15	Year End Utility Deferrals Less: ARO Related Deferrals Less: Other Excluded Deferrals Transmission Related Deferrals	FF1, p. 276 - 277, In 9, Col. (k) Company Records - Note 1 Company Records - Note 1 Ln 12 - In 13 - In 14	902,525 0 783,042 119,483	1,803,691 0 1,556,207 247,484	1,353,108 - 1,169,625 183,484
16	Account 190				
17 18 19 20	Year End Utility Deferrals Less: ARO Related Deferrals Less: Other Excluded Deferrals Transmission Related Deferrals	FF1, p. 234, ln 8, Col. (c) Company Records - Note 1 Company Records - Note 1 Ln 17 - In 18 - In 19	477,622 0 457,486 20,136	960,179 0 843,387 116,792	718,901 - 650,437 68,464
21	Account 255				
22 23 24 25	Year End ITC Balances Less: Balances Not Qualified for Ratebase ITC Balances Includeable Ratebase Transmission Related Deferrals	FF1, p. 266-267, ln 8, Col. (h) Company Records - Note 1 Ln 22 - ln 23 Company Records - Note 1	55,004 0 55,004 11,643	107,557 0 107,557 22,844	81,281 - 81,281 17,244

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

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

AEP East Companies Cost of Service Formula Rate Using 2012 FF1 Balances Worksheet C Supporting Working Capital Rate Base Adjustments KINGSPORT POWER COMPANY

		Tall	OOI OINT TOWEN OC	71VII 7 (1 4 1				
(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(1)
		<u>Materials</u>	s & Supplies					
<u>Line</u> <u>Number</u> 1		Source	Balance @ December 31, 2012	Balance @ December 31, 2011	Average Balance for 2012			
2	Transmission Materials & Supplies	FF1, p. 227, ln 8, Col. (c) & (b)	232	1,059	646			
3	General Materials & Supplies	FF1, p. 227, ln 11, Col. (c) & (b)	3,123	110	1,617			
4	Stores Expense (Undistributed)	FF1, p. 227, ln 16, Col. (c) & (b)	0	0	-			
		Prenayment B	Salance Summary					
5		Average of YE Balance	Excludable Balances	100% Transmission <u>Related</u>	Transmission Plant <u>Related</u>	Transmission Labor <u>Related</u>	Total Included in Ratebase (E)+(F)+(G)	
6 7 8	Totals as of December 31, 2012 Totals as of December 31, 2011 Average Balance	2,415,665 2,103,919 2,259,792	(3,499,352) (3,449,377) (3,474,365)	0	147,105 132,556 139,831	5,767,913 5,420,740 5,594,327	5,915,018 5,553,296 5,734,157	_
9 <u>Acc. No.</u>	<u>Description</u>	Prepayments Account 165 - Barrel 2012 YE Balance	alance @ 12/31/20 Excludable Balances	12 100% Transmission <u>Related</u>	Transmission Plant <u>Related</u>	Transmission Labor <u>Related</u>	Total Included in Ratebase (E)+(F)+(G)	<u>Explanation</u>
10 1650001 11 165000212 12 165000213 13 1650003 14 1650004 15 1650005 16 1650006 17 1650009 18 1650010 19 1650014 20 1650016 21 1650021 22 1650023	Prepaid Insurance Prepaid Taxes Prepaid Taxes Prepaid Rents Prepaid Interest Prepaid Employee Benefits Other Prepayments Prepaid Carry Cost-Factored AR Prepaid Pension Benefits FAS 158 Qual Contra Asset FAS 112 ASSETS Prepaid Insurance - EIS Prepaid Lease	27,614 1,783,096 434,490 0 0 0 5,809 5,767,913 (5,767,913) 0 119,491 45,166	1,783,096 434,490 - - - - 5,809 (5,767,913) - - 45,166		27,614	- 5,767,913 - -	- - - - -	Plant Related Insurance Policies Prepaid Taxes - Distribution Prepaid Taxes - Distribution AR Factoring - Retail Only Prefunded Pension Expense SFAS 158 Offset
	Subtotal - Form 1, p 111.57.c	2,415,665	(3,499,352)	0	147,105	5,767,913	5,915,018	_
OO Ass No	D ecember 2	Prepayments Account 165 - Ba	Excludable	100% Transmission	Transmission Plant	Transmission Labor	Total Included in Ratebase	Fourton
23 <u>Acc. No.</u>	<u>Description</u>	YE Balance	<u>Balances</u>	<u>Related</u>	Related	<u>Related</u>	(E)+(F)+(G)	Explanation
24 1650001 25 165000211 26 1650003 27 1650004 28 1650005 29 1650006 30 1650009 31 1650010 32 1650014 33 1650016 34 1650021 35 1650023	Prepaid Insurance Prepaid Taxes Prepaid Rents Prepaid Interest Prepaid Employee Benefits Other Prepayments Prepaid Carry Cost-Factored AR Prepaid Pension Benefits FAS 158 Qual Contra Asset FAS 112 ASSETS Prepaid Insurance - EIS Prepaid Lease	31,453 1,918,196 0 0 0 6,646 5,420,740 (5,420,740) 0 101,103 46,521	1,918,196 - - - - - 6,646 (5,420,740) - - 46,521		31,453 - 101,103	- 5,420,740 - -	- - - -	Plant Related Insurance Policies Prepaid Taxes AR Factoring - Retail Only Prefunded Pension Expense SFAS 158 Offset

(3,449,377)

132,556

5,420,740

5,553,296

2,103,919

Subtotal - Form 1, p 111.57.d

AEP East Companies Cost of Service Formula Rate Using 2012 FF1 Balances Worksheet D Supporting IPP Credits KINGSPORT POWER COMPANY

<u>Line</u> <u>Number</u>	(A) <u>Description</u>	(B) <u>2012</u>
1	Net Funds from IPP Customers 12/31/2012 (2012 FORM 1, P269, line 24.b)	-
2	Interest Accrual (Company Records - Note 1)	-
3	Revenue Credits to Generators (Company Records - Note 1)	-
4 5 6	Other Adjustments Accounting Adjustment (Company Records - Note 1)	
7	Net Funds from IPP Customers 12/31/2012 (2012 FORM 1, P269, line 24.f)	
8	Average Balance for Year as Indicated in Column ((In 1 + In 7)/2)	

Note 1 On this worksheet Company Records refers to KINGSPORT POWER COMPANY's general ledger.

AEP East Companies Cost of Service Formula Rate Using 2012 FF1 Balances Worksheet E Supporting Revenue Credits KINGSPORT POWER COMPANY

<u>Line</u> Number	<u>Description</u>	<u>Total</u> <u>Company</u>	Non- Transmission	<u>Transmission</u>
1	Account 450, Forfeited Discounts (FF1 p.300.16.(b); Company Records - Note 1)	243,738	243,738	-
2	Account 451, Miscellaneous Service Revenues (FF1 p.300.17.(b); Company Records - Note 1)	18,683	18,683	-
3	Account 454, Rent from Electric Property (FF1 p.300.19.(b); Company Records - Note 1)	1,320,393	1,281,248	39,145
4	Account 4560015, Associated Business Development - (Company Records - Note 1)	308,757	41,847	266,910
5	Account 456 - Other Electric Revenues - (Company Records - Note 1)	2,662,417	2,662,417	-
6	Subtotal - Other Operating Revenues (Company Total equals (FF1 p. 300.26.(b))	4,553,988	4,247,933	306,055
7	Accounts 4470004 & 5, Revenues from Grandfathered Transmission Contracts - (Company Records - Note 1)	-	- 1	-
8	Total Other Operating Revenues To Reduce Revenue Requirement	4,553,988	4,247,933	306,055

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

AEP East Companies Cost of Service Formula Rate Using 2012 FF1 Balances Worksheet F Supporting Allocation of Specific O&M or A&G Expenses KINGSPORT POWER COMPANY

	(A)	(B)	(C)	(D)	(E) 100%	(F)
<u>Line</u> Number	<u>ltem No.</u>	<u>Description</u>	<u>2012</u> <u>Expense</u>	100% Non-Transmission	Transmission Specific	Explanation
		Regulatory O&M Deferrals & Amortizations				
1 2		No Applicable Charges for KGPCO	-			
3						
4		Total	0			
		Detail of Account 561 Per FERC Form 1				
5	FF1 p 321.84.b	561 - Load Dispatching	0			
6	FF1 p 321.85.b	561.1 - Load Dispatch - Reliability	238			
γ	FF1 p 321.86.b	561.2 - Load Dispatch - Monitor & Operate Trans System 561.3 - Load Dispatch - Trans Service & Scheduling	42,378			
8 9	FF1 p 321.87.b FF1 p 321.88.b	561.4 - Scheduling, System Control & Dispatch	(3) 1,263			
10	FF1 p 321.89.b	561.5 - Reliability, Planning and Standards Development	6,581			
11	FF1 p 321.90.b	561.6 - Transmission Service Studies	0,001			
12	FF1 p 321.91.b	561.7 - Generation Interconnection Studies	0			
13	FF1 p 321.92.b	561.8 - Reliability, Planning and Standards Development Servi	0			
14		Total of Account 561	50,457	•		
		Account 928				
15	9280000	Regulatory Commission Exp	-	-	-	
16	9280001	Regulatory Commission Exp-Adm	(1)	(1)	-	
17	9280002	Regulatory Commission Exp-Case	38	38	•	
18		Total	37	37		
		Account 930.1				
19	9301000	General Advertising Expenses	145	145	_	
20	9301010	Publicity	73	73	_	
21	9301011	Dedications, Tours, & Openings	0	0	-	
22	9301012	Public Opinion Surveys	636	636	-	
23	9301013	Movies Slide Films & Speeches	-	-	-	
24	9301014	Video Communications	1	1	-	
25	9301015	Other Corporate Comm Exp	2,169	2,169	-	
26		Total	3,024	3,024	-	
		Account 930.2				
27	9302000	Misc General Expenses	(6,008)			
28	9302003	Corporate & Fiscal Expenses	866			
29 30	9302004	Research, Develop&Demonstr Exp	469	469		
30 31	9302005 9302006	Nucl Fac Ins - Replce Engy Cst Assoc Bus Dev - Materials Sold	0	0		
32	9302006	Assoc Business Development Exp	189,776	_	172,732	
33		Total	185,103	12,371	172,732	
				•	· · · · · · · · · · · · · · · · · · ·	

Formula Rate
KGPCo WS G State Tax Rate
Page 22 of 34

AEP East Companies Cost of Service Formula Rate Using 2012 FF1 Balances Worksheet G Supporting - Development of Composite State Income Tax Rate KINGSPORT POWER COMPANY

Tennessee Excise Tax Rate	6.50%	
Apportionment Factor - Note 2	99.32%	
Effective State Tax Rate		6.46%
	_	
Total Effective State Income Tax Rate		6.46%

- The Ohio State Income Tax is being phased-out prorata over a 5 year period from 2005 through 2009. The taxable portion of income is 0% 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 Activites 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 2012 FF1 Balances
Worksheet H Supporting Taxes Other than Income
KINGSPORT POWER COMPANY

	(A)	(B)	(C)	(D)	(E)	(F)
Line No.	Account	Total Company	Property	Labor	Other	Non-Allocable
		NOTE 1				
1	Revenue Taxes					
2	Gross Receipts Tax	3,846,121				3,846,121
3	Real Estate and Personal Property Taxes	014.000	014.000			
4 5	Real and Personal Property - Tennessee	914,068 0	914,068			
5	Real and Personal Property - Other	U	-			
6	Payroll Taxes					
7	Federal Insurance Contribution (FICA)	146,784		146,784		
8	Federal Unemployment Tax	388		388		
9	State Unemployment Insurance	4,725		4,725		
10	Production Taxes					
11	State Severance Taxes	-				-
12	Miscellaneous Taxes					
13	State Business & Occupation Tax	-				-
14	State Public Service Commission Fees	484,651			484,651	
15	State Franchise Taxes	(81,618)			(81,618)	
16	State Lic/Registration Fee	1,872			1,872	
17	Misc. State and Local Tax	-			-	4.070
18	Sales & Use	1,878				1,878
19	Federal Excise Tax	-				-
20	Michigan Single Business Tax	-				-
21	Total Taxes by Allocable Basis	5,318,869	914,068	151,897	404,905	3,847,999
	(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					
	Func	tional Property Tax		Diatolbustias	Canaral	Tatal
22	Functionalized Not Diant (Higt TCOS I no 212 thru 222)	<u>Production</u>	Transmsission	Distribution	General	<u>Total</u>
22	Functionalized Net Plant (Hist. TCOS, Lns 212 thru 222) TENNESSEE JURISDICTION	-	11,738,689	69,677,969	1,825,976	83,242,634
23	Percentage of Plant in TENNESSEE JURISDICTION		100.00%	100.00%	100.00%	
24	Net Plant in TENNESSEE JURISDICTION (Ln 22 * Ln 23)	-	11,738,689	69,677,969	1,825,976	83,242,634
25	Less: Net Value of Exempted Generation Plant	-				
26	Taxable Property Basis (Ln 24 - Ln 25)		11,738,689	69,677,969	1,825,976	83,242,634
27	Relative Valuation Factor		100%	100%	100%	3
28	Weighted Net Plant (Ln 26 * Ln 27)	-	11,738,689	69,677,969	1,825,976	
29	General Plant Allocator (Ln 28 / (Total - General Plant))	0.00%	14.42%	85.58%	-100.00%	
30	Functionalized General Plant (Ln 29 * General Plant)	-	263,270	1,562,706	(1,825,976)	-
31	Weighted TENNESSEE JURISDICTION Plant (Ln 28 + 30)	-	12,001,959	71,240,675	-	83,242,634
32	Functional Percentage (Ln 31/Total Ln 31)	0.00%	14.42%	85.58%		
33	Functionalized Expense in TENNESSEE JURISDICTION	-	131,791	782,277		914,068
34	Total Other Jurisdictions: (Line 5 * Net Plant Allocator)		-			-
	,					
35	Total Func. Property Taxes (Sum Lns 33, 34)		131,791	782,277		914,068

AEP East Companies

Cost of Service Formula Rate Using 2012 FF1 Balances
Worksheet H-1 Form 1 Source Reference of Company Amounts on WS H
KINGSPORT POWER COMPANY

	(A)	(B)	(C)	(D)
Line	Annual Tay Eynanaaa by Tyna (Nata 1)	Total	FERC FORM 1 Tie-Back	EEDC FORM 4 Reference
No.	Annual Tax Expenses by Type (Note 1)	Company	пе-васк	FERC FORM 1 Reference
4	Davienus Tavas			
1 2	Revenue Taxes Gross Receipts Tax	3,846,121		
_		3,0 : 3, : = :	1,918,196	P.263 In 34 (i)
			1,927,925	P.263 In 35 (i)
3	Real Estate and Personal Property Taxes			
4	Real and Personal Property - Tennessee	914,068		
				P.263 In 19 (i)
5	Real and Personal Property - Other	_	989,100	P.263 In 20 (i)
3	Real and Leisonal Lioperty - Other	_	-	
6	Payroll Taxes			
7	Federal Insurance Contribution (FICA)	146,784	146 794	D 262 In E (i)
8	Federal Unemployment Tax	388	140,764	P.263 In 5 (i)
			388	P.263 In 6 (i)
9	State Unemployment Insurance	4,725	4.705	D 000 L 04 (')
10	Production Taxes		4,725	P.263 In 31 (i)
11	State Severance Taxes	-		
	-		-	
12 13	Miscellaneous Taxes State Business & Occupation Tax	_		
10	Otate Business & Occupation Tax	_	-	
14	State Public Service Commission Fees	484,651		
15	State Franchise Taxes	(81,618)		P.263.1 In 3 (i)
10	Otate i fancinse faxes	(81,010)		P.263 In 27 (i)
			-	P.263 In 29 (i)
16	State Lic/Registration Fee	1,872		
			1,802	P.263.1 In 13 (i)
				P.263.1 In 19 (i)
			25	P.263.1 In 20 (i)
17	Misc. State and Local Tax	-		
4.0		4 070	-	
18	Sales & Use	1,878	240	P.263 In 14 (i)
				P.263 In 15 (i)
19	Federal Excise Tax	-		
20	Michigan Single Business Tax	_	-	
20	whenigan onigic business rax	-	-	
				<u>.</u>
21	Total Campany Amount Tipe to FFL n 114 L n 14 (a)	5,318,869	5,318,869	=
	(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.

(1)

AEP East Companies

Cost of Service Formula Rate Using 2012 FF1 Balances Worksheet I Supporting Transmission Plant in Service Additions KINGSPORT POWER COMPANY

(A) (B) (C) (D) (E) (F) (G) (H)

I. Calculation of Composite Depreciation Rate

1	Transmission Plant @ Beginning of Historic Period (2012) (P.206, In 58,(b)):	20,264,445
2	Transmission Plant @ End of Historic Period (2012) (P.207, In 58,(g)):	22,330,531
3		42,594,976
4	Average Balance of Transmission Investment	21,297,488
5	Annual Depreciation Expense, Historic TCOS, In 276	533,521
6	Composite Depreciation Rate	2.51%
7	Round to 2.51% to Reflect a Composite Life of 40 Years	2 51%

II. Calculation of Property Placed in Service by Month and the Related Depreciation Expense

	Month in			Composite Annual Depreciation		Annual			No. Months	De	irst Year preciation
8	Service	Capi	talized Balance	Rate	De	preciation	Monti	nly Depreciation	Depreciation	E	xpense
9	January	\$	2,640,060	2.51%	\$	66,266	\$	5,522	11	\$	60,742
10	February	\$	49,040	2.51%	\$	1,231	\$	103	10	\$	1,030
11	March	\$	118,797	2.51%	\$	2,982	\$	248	9	\$	2,232
12	April	\$	93,618	2.51%	\$	2,350	\$	196	8	\$	1,568
13	May	\$	69,256	2.51%	\$	1,738	\$	145	7	\$	1,015
14	June	\$	145,532	2.51%	\$	3,653	\$	304	6	\$	1,824
15	July	\$	65,096	2.51%	\$	1,634	\$	136	5	\$	680
16	August	\$	70,442	2.51%	\$	1,768	\$	147	4	\$	588
17	September	\$	209,337	2.51%	\$	5,254	\$	438	3	\$	1,314
18	October	\$	55,626	2.51%	\$	1,396	\$	116	2	\$	232
19	November	\$	57,710	2.51%	\$	1,449	\$	121	1	\$	121
20	December	\$	2,553,834	2.51%	\$	64,101	\$	5,342	0	\$	-
21	Investment	\$	6,128,348	•				Depr	eciation Expense	\$	71,346

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 subsidiar
24 (l n 7 * l n 22)	\$ - <== This input area is for additional Depreciation Expense

IV. List of Major Projects Expected to be In-Service in 2012

		Estimated Cost (000's)	Month in Service
25 Major Zonal Projects		<u>(000 S)</u>	<u>Jei vice</u>
26 N/A		\$0	Multiple
27	Subtotal	\$0	
28 PJM Socialized/Beneficiary Allocated Regional Projects			
29 N/A		\$0	
30	Subtotal	\$0	

AEP East Companies Cost of Service Formula Rate Using 2012 FF1 Balances Worksheet J Supporting Calculation of PROJECTED PJM RTEP Project Revenue Requirement Billed to Benefiting Zones KINGSPORT POWER COMPANY

Page 1 of 2

Incentive Amounts

SUMMARY OF PROJECTED ANNUAL RTEP REVENUE REQUIREMENTS

PROJECTED YEAR

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, In 164)

Project ROE Incentive Adder

ROE with additional basis point incentive

11.49%

-==ROE Adder Cannot Exceed 125 Basis Points

11.49%

-== 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, Ins 162 through164)

	<u>%</u>	<u>Cost</u>	Weighted cost
Long Term Debt	40.04%	4.52%	1.810%
Preferred Stock	0.00%	0.00%	0.000%
Common Stock	59.96%	11.49%	<u>6.890%</u>
		R =	8.700%

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

Rate Base (Projected TCOS, In 78)	14,947,799
R (from A. above)	8.700%
Return (Rate Base x R)	1,300,385

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

Return (from B. above)	1,300,385
Effective Tax Rate (Projected TCOS, In 126)	51.06%
Income Tax Calculation (Return x CIT)	663,979
ITC Adjustment	-
Income Taxes	663,979

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, In 1)	3,760,479
T.E.A. & Lease Payments (Projected TCOS, Lns 105 & 106)	-
Return (Projected TCOS, In 134)	1,300,385
Income Taxes (Projected TCOS, In 133)	663,979
Annual Revenue Requirement, Less TEA Charges, Return and Taxes	1.796.115

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

Annual Revenue Requirement, Less TEA Charges, Return and Taxes	1,796,115
Return (from I.B. above)	1,300,385
Income Taxes (from I.C. above)	663,979
Annual Revenue Requirement, with Basis Point ROE increase	3,760,479
Depreciation (Projected TCOS, In 111)	533,521
Annual Rev. Req, w/ Basis Point ROE increase, less Depreciation	3,226,958

C. Determine FCR with hypothetical basis point ROE increase.

Net Transmission Plant (Projected TCOS, In 48) Annual Revenue Requirement, with Basis Point ROE increase FCR with Basis Point increase in ROE	11,738,689 3,760,479 32.03%
Annual Rev. Req, w / Basis Point ROE increase, less Dep.	3,226,958
FCR with Basis Point ROE increase, less Depreciation	27.49%
FCR less Depreciation (Projected TCOS, In 9)	<u>18.28%</u>
Incremental FCR with Basis Point ROE increase, less Depreciation	9.21%

III. Calculation of Composite Depreciation Rate

Transmission Plant @ Beginning of Historic Period (2012) (P.206, In 58,(b)):	20,264,445
Transmission Plant @ End of Historic Period (2012) (P.207, In 58,(g)):	22,330,531
Subtotal	42,594,976
Average Transmission Plant Balance for 2012	21,297,488
Annual Depreciation Rate (Projected TCOS, In 111)	533,521
Composite Depreciation Rate	2.51%
Depreciable Life for Composite Depreciation Rate	39.92
Round to nearest whole year	40

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

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

A. Base Plan Facilities

Facilities receiving incentives accepted by FERC in Docket No.	(e.g. ER05-925-000)	Current Projected Year ARR	-
		Current Projected Year ARR w/ Incentive	-
Project Description:		Current Projected Year Incentive ARR	-

Details											
Investment		Current Year				2008	CUMULA	TIVE HISTORY OF P	ROJECTED ANNUAL	REVENUE REQUIRE	MENTS:
Service Year (yyyy)	2008	ROE increase accept	ed by FERC (Basis Po	oints)		-	CUMULATIVE HIST	ORY OF PROJECTE	O ANNUAL REVENUE	REQUIREMENTS:	
Service Month (1-12)		FCR w/o incentives, l		,		18.28%			WITHOUT INCENTIV		OR YEAR
Useful life	40	FCR w/incentives app	oroved for these facilities	es, less dep.		18.28%			HISTORY OF PROJE		
CIAC (Yes or No)	No	Annual Depreciation E	Expense	,		-	LIFE OF THE				
·							RTEP Projected		RTEP Projected		
							Rev. Req't.From		Rev. Req't.From		
							Prior Year		Prior Year		
Investment	Beginning	Depreciation	Ending	RTEP Rev. Req't.	RTEP Rev. Req't.	Incentive Rev.	Template		Template		
Year	Balance	Expense	Balance	w/o Incentives	with Incentives **	Requirement ##	w/o Incentives		with Incentives **		
2008	-	-	-	-	-	\$ -					
2009	-	-	-	-	-	\$ -					
2010	-	-	-	-	-	\$ -					
2011	-	-	-	-	-	\$ -					
2012	-	-	-	-	-	\$ -					
2013	-	-	-	-	-	\$ -					
2014	-	-	-	-	-	\$ -					
2015	-	-	-	-	-	\$ -					
2016	-	-	-	-	-	\$ -					
2017	-	-	-	-	-	\$ -					
2018	-	-	-	-	-	\$ -					
2019	-	-	-	-	-	\$ -					
2020	-	-	-	-	-	\$ -					
2021	-	-	-	-	-	\$ -					
2022	-	-	-	-	-	\$ -					
2023	-	-	-	-	-	\$ -					
2024	-	-	-	-	-	\$ -					
2025	-	-	-	-	-	\$ -					
2026	-	-	-	-	-	\$ -					
2027	-	-	-	-	-	\$ -					
2028	-	-	-	-	-	\$ -					
2029	-	-	-	-	-	\$ -					
2030	-	-	-	-	-	\$ -					
2031	-	-	-	-	-	\$ -					
2032	-	-	-	-	-	\$ -					
2033	-	-	-	-	-	\$ -					
2034	-	-	-	-	-	\$ -					
2035	-	-	-	-	-	\$ -					
2036	-	-	-	-	-	\$ -					
2037	-	-	-	-	-	\$ -					
2038	-	-	-	-	-	\$ -					
2039	-	-	-	-	-	\$ -					
2040	-	-	-	-	-	\$ -					
2041	-	-	-	-	-	\$ -					
2042	-	-	-	-	-	\$ -					
2043	-	-	-	-	-	\$ -					
2044	-	-	-	-	-	\$ -					
2045	-	-	-	-	-	\$ -					
2046	-	-	-	-	-	\$ -					
2047	-	-	-	-	-	\$ -					
2048	-	-	-	-	-	\$ -					
2049	-	-	-	-	-	\$ -					
2050	-	-	-	-	-	\$ -					
2051	1		I	Ī	Ī	r c					

Project Totals

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

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

KGPCo WS J PROJECTED RTEP RR Page 27 of 34

Page 2 of 2

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

AEP East Companies Cost of Service Formula Rate Using 2012 FF1 Balances Worksheet K Supporting Calculation of TRUE-UP PJM RTEP Project Revenue Requirement Billed to Benefiting Zones KINGSPORT POWER COMPANY

Page 1 of 2

١.

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

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

ROE w/o incentives (True-U	lp TCOS, ln 164)	11.49%	
Project ROE Incentive Adde	r		0 <==F	ROE Adder Cannot Exceed 100 Basis Points
ROE with additional 0 basis	point incentive		11.49% <== I	ROE Including Incentives Cannot Exceed 12.5% Until July 1, 2012
Determine R (cost of long to	erm debt, cost o	f preferred stock and equit	y percentage is from the Tru	e-Up TCOS, Ins 162 through164)
	<u>%</u>	<u>Cost</u>	Weighted cost	
Long Term Debt	40.24%	4.52%	1.819%	
Preferred Stock	0.00%	0.00%	0.000%	
Common Stock	59 76%	11 49%	6 867%	

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

Rate Base (True-Up TCOS, In 78)	8,871,981
R (from A. above)	8.685%
Return (Rate Base x R)	770,568

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

Return (from B. above)	770,568
Effective Tax Rate (True-Up TCOS, In 126)	50.97%
Income Tax Calculation (Return x CIT)	392,762
ITC Adjustment	-
Income Taxes	392,762

II. Calculate Net Plant Carrying Charge Rate (Fixed Charge Rate or FCR) with hypothetical 0 basis point ROE increase.

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

Annual Revenue Requirement (True-Up TCOS, In 1)	2,885,916
T.E.A. & Lease Payments (True-Up TCOS, Lns 105 & 106)	-
Return (True-Up TCOS, In 134)	770,568
Income Taxes (True-Up TCOS, In 133)	392,762
Annual Revenue Requirement, Less TEA	1,722,587
Charges, Return and Taxes	

B. Determine Annual Revenue Requirement with hypothetical 0 basis point increase in ROE.

Annual Revenue Requirement, Less TEA Charges, Return and Taxes	1,722,587
Return (from I.B. above)	770,568
Income Taxes (from I.C. above)	392,762
Annual Revenue Requirement, with 0 Basis Point ROE increase	2,885,916
Depreciation (True-Up TCOS, In 111)	533,521
Annual Rev. Req, w/ 0 Basis Point ROE	2,352,395
increase, less Depreciation	

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

Net Transmission Plant (True-Up TCOS, In 48) Annual Revenue Requirement, with 0 Basis Point ROE increase FCR with 0 Basis Point increase in ROE	10,899,330 2,885,916 26.48%
Annual Rev. Reg, w / 0 Basis Point ROE increase, less Dep.	2,352,395
FCR with 0 Basis Point ROE increase, less Depreciation	21.58%
FCR less Depreciation (True-Up TCOS, In 9)	21.58%
Incremental FCR with 0 Basis Point ROE	0.00%
increase, less Depreciation	

III. Calculation of Composite Depreciation Rate

Transmission Plant @ Beginning of Historic Period () (P.206, In 58,(b)):	20,264,445
Transmission Plant @ End of Historic Period () (P.207, ln 58,(g)):	22,330,531_
Subtotal	42,594,976
Average Transmission Plant Balance for	21,297,488
Annual Depreciation Rate (True-Up TCOS, In 111)	533,521
Composite Depreciation Rate	2.51%
Depreciable Life for Composite Depreciation Rate	39.92
Round to nearest whole year	40

SUMMARY OF TRUED-UP ANNUAL REVENUE REQUIREMENTS FOR RTEPPROJECTS							
		Rev Require	1	W Incentives		Incentive Am	ounts
TRUE-UP YEAR	2012						
As Proj	ected in Prior Year WS J					\$	-
	Actual after True-up	\$	- ;	\$	-	\$	-
Т	rue-up of ARR For 2012		-		-		-
	-						

KgPCo 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

Project Description:

Facilities receiving incentives accepted by FERC in Docket No.

(e.g. ER05-925-000)

2012 Rev Require Prior Yr Projected Prior Yr True-Up

True-Up Adjustment

Details Investment Current Year 2012 Service Year (yyyy) 2008 ROE increase accepted by FERC (Basis Points) Service Month (1-12) FCR w/o incentives, less depreciation 21.58% 40 FCR w/incentives approved for these facilities, less dep. Useful life 21.58% No Annual Depreciation Expense

CIAC (Yes or No) Beginning Depreciation **Ending** RTEP Rev. Req't. RTEP Rev. Req't. Investment Average Incentive Rev. Balance Balance with Incentives ** Requirement ## Year Expense Balance w/o Incentives 2008 2009 2010 2011 2012 2013 2014 2015 2016 2017 2018 2019 2020 2021 2022 2023 2024 2025 2026 2027 2028 2029 2030 2031 2032 2033 2034 2035 2036 2037 2038 2039 2040 2041 2042 2043 2044 2045 2046 2047 2048 2049 2050 2051 2052 2053 2054 2055 2056 2057 2058 2059 2060 2061 2062

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

W Incentives

LIFE OF THE PROJECT.						
RTEP Projected		RTEP Projected				
Rev. Req't.From	RTEP Rev Req't	Rev. Req't.From	RTEP Rev Req't	True-up of		
Prior Year WS J	True-up	Prior Year WS J	True-up	Incentive		
w/o Incentives	w/o Incentives	with Incentives **	with Incentives **	with Incentives **		
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Project Totals

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

KGPCo WS K TRUE-UP RTEP RR Page 29 of 34

Incentive Amounts

Page 2 of 2

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

AEP East Companies Cost of Service Formula Rate Using 2012 FF1 Balances Worksheet L Supporting Projected Cost of Debt KINGSPORT POWER COMPANY

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

	(A)	(B)	(C)	(D)	(E)
<u>Line</u> Number	<u>Issuance</u>	Principle Outstanding	Interest Rate	Annual Expense (See Note S on Projected Template)	<u>Notes</u>
1	Long Term Debt (FF1.p. 256-257.h)			1	
2	Advances From Associated Co.	20,000,000	4.520%	904,000	
4	Installment Purchase Contracts (FF1.p. 256	<u>-257.h, a)</u>			
5	N/A for Kingsport Power Company			-	
6 7				_	
8					
9					
10				-	
11 12				•	
13					
14				-	
15 16				•	
17					
18				-	
19				-	
20 21				•	
22					
23					
24				-	
25 26			0.000%	-	
20			0.00070		
27	Issuance Discount, Premium, & Expenses:				
28	Auction Fees	FF1.p. 256 & 257.Lines Described as F	ees	-	
29 30	Allowable Hedge Amortization (See Ln 45 Belo Amort of Debt Discount and Expenses	эw) FF1.p. 117.63.c			
31	Amort of Debt Premimums (Enter Negative)	FF1.p. 117.65.c		-	
32 33	Reacquired Debt: Amortization of Loss	FF1.p. 117.64.c			
34	Amortization of Coss Amortization of Gain	FF1.p. 117.64.c			
35	Total Interest on Long Term Debt	20,000,000	4.52%	904,000	
36	Preferred Stock (FF1.p. 250-251)	Preferred Shares Outstanding			
37	4.125% Series - \$100 - Shares O/S	-	0.00%	-	
38 39				•	
39				-	
40	Dividends on Preferred Stock	-	0.00%	-	
41	Net Total Hedge Gains and Losses (WS M, L	` ','		-	
42	Total Projected Capital Structure Balance for 2			49,955,380	
43 44	Financial Hedge Recovery Limit - Five Basis Limit of Recoverable Amount	Points of Total Capital		0.0005 24,978	
45	Recoverable Hedge Amortization (Lesser o	f Ln 41 or Ln 44)		-	
	- ,	•			

AEP East Companies Transmission Cost of Service Formula Rate KINGSPORT POWER COMPANY

Worksheet M Supporting Calculation of Capital Structure and Weighted Average Cost of Capital Based on Average of Balances At 12/31/2011 & 12/31/2012

(A)	(B)	(C)	(D)	(E)
<u>Line</u> Developr	ment of Average Balance of Common Equity	Balances @ 12/31/2012	Balances @ 12/31/2011	Average
2 I 3 I 4 I	Proprietary Capital (112.16.c&d) Less Preferred Stock (Ln 55 Below) Less Account 216.1 (112.12.c&d) Less Account 219.1 (112.15.c&d) Average Balance of Common Equity	29,956,296 0 0 916 29,955,380	29,450,188 0 0 -2,751 29,452,939	29,703,242 - 0 -918 29,704,160
<u>Developr</u>	ment of Cost of Long Term Debt Based on A	verage Outstanding B	<u>alance</u>	
7 8 9 10 11	Bonds (112.18.c&d) Less: Reacquired Bonds (112.19.c&d) LT Advances from Assoc. Companies (112.20.c&d) Senior Unsecured Notes (112.21.c&d) Less: Fair Value Hedges (See Note on Ln 12 below) Total Average Debt NOTE: The balance of fair value hedges on outstanditerm debt included in the formula's capital structure.		20,000,000 0 0 20,000,000 e excluded from the	20,000,000 0 0 20,000,000 balance of long
14 15 16 17 / 18 / 19	Annual Interest Expense for 2012 Interest on Long Term Debt (256-257.33.i) Less: Total Hedge Gain/Expense Accumulated from p 256 Form 1 included in Ln 14 and shown in Ln 34 below. Plus: Allowed Hedge Recovery From Ln 39 below. Amort of Debt Discount & Expense (117.63.c) Amort of Loss on Reacquired Debt (117.64.c) Less: Amort of Premium on Debt (117.65.c) Less: Amort of Gain on Reacquired Debt (117.66.c)	6-257, col. (i) of FERC		904,000

CALCULATION OF RECOVERABLE HEDGE GAINS/LOSSES

21 Total Interest Expense (Ln 14 + Ln 17 + Ln 18 - Ln 19 - Ln 20)

22 Average Cost of Debt for 2012 (Ln 21/Ln 11)

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.

					Amortizatio	n Period
HEDGE AMOUNTS BY ISSUANCE (FROM p. 256-257	Total Hedge	Less Excludable Amounts (See	Net Includable	Remaining Unamortized		
(i) of the FERC Form 1)	(Gain)/Loss for 2012	NOTE on Line 23)	Hedge Amount	Balance	Beginning	Endin
24 Senior Unsecured Notes	0	-	-			
25 Senior Unsecured Notes	0		-			
6 Senior Unsecured Notes			-			
7 Senior Unsecured Notes	0		-			
8 Senior Unsecured Notes	0		-			
9 Senior Unsecured Notes	0		-			
O Senior Unsecured Notes	0		-			
1 Senior Unsecured Notes	0		-			
2 Senior Unsecured Notes 3 Senior Unsecured Notes	0		-			
 7 Financial Hedge Recovery Limit - Five Basis Points of To 8 Limit of Recoverable Amount 9 Recoverable Hedge Amortization (Lesser of Ln 35 or I 	•	I	0.0005 24,852 -			
ppment of Cost of Preferred Stock						
Preferred Stock			<u>Average</u>			
10 0% Series - 0 - Dividend Rate (p. 250-251. 7 & 10.a)	0.00%	0.00%				
11 00/ Corios O Dor Volus (n. 250 251 9 s)	\$	- \$				
11 0% Series - 0 - Par Value (p. 250-251. 8.c)						
,	-	-				
42 0% Series - 0 - Shares O/S (p.250-251. 8 & 11.e)	- -	-	-			
12 0% Series - 0 - Shares O/S (p.250-251. 8 & 11.e) 13 0% Series - 0 - Monetary Value (Ln 41 * Ln 42)	-	- - -				
42 0% Series - 0 - Shares O/S (p.250-251. 8 & 11.e) 43 0% Series - 0 - Monetary Value (Ln 41 * Ln 42) 44 0% Series - 0 - Dividend Amount (Ln 40 * Ln 43)	- -	- - -	- -			
41 0% Series - 0 - Pair Value (p. 250-251, 8.c.) 42 0% Series - 0 - Shares O/S (p.250-251, 8 & 11.e) 43 0% Series - 0 - Monetary Value (Ln 41 * Ln 42) 44 0% Series - 0 - Dividend Amount (Ln 40 * Ln 43) 45 0% Series Dividend Rate (p. 250-251.a) 46 0% Series Par Value (p. 250-251.c)	- - -	-	-			

904,000

4.52%

41 0% Series - 0 - Fai value (p. 250-251, 6.0)	Φ	- ψ	_		
42 0% Series - 0 - Shares O/S (p.250-251. 8 & 11.e) 43 0% Series - 0 - Monetary Value (Ln 41 * Ln 42)		_		_	
44 0% Series - 0 - Dividend Amount (Ln 40 * Ln 43)		-	-	- -	
77 070 Concs o Dividona Amount (En 40)					
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)	<u></u>	0.00%	0.00%		

AEP East Companies Cost of Service Formula Rate Using 2012 FF1 Balances Worksheet N - Gains (Losses) on Sales of Plant Held For Future Use KINGSPORT POWER COMPANY

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

	(A)	(B)	(C) Function	(D)	(E)	(F)	(G) Functional	(H) Functionalized	(I) FERC
Line	Date	Property Description	(T) or (G) T = Transmissi G = General	Basis ion	Proceeds	(Gain) / Loss	Allocator	Proceeds (Gain) / Loss	Account
1						-	0.000%	-	
2						-	0.000%	-	
3						-	0.000%	-	
4			N	Net (Gain) or Lo	oss for 2012			<u> </u>	

AEP East Companies

Cost of Service Formula Rate Using 2012 FF1 Balances

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

Total AEP East Operating Company PBOP Settlement Amount

48,100,000

Allocation of PBOP Settlement Amount for 2012

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 2012	Actual Expense	Allowable Expense	One Year Functional Expense (Over)/Under
		(A) (Line 14)	(B)=(A)/Total (A)	(C)=(B) * 48100000	(D)	(E)=(A) * (D)	(F)=(C) * (D)	(G)=(E) - (F)
1 APC	Co	11,359,793	27.78%	13,362,440	7.081%	804,397	946,207	(141,809)
2								
3 I&M		10,586,657	25.89%	12,453,006	4.206%	445,250	523,744	(78,494)
4 KPC	Co	2,188,039	5.35%	2,573,774	9.694%	212,116	249,511	(37,394)
5 KNG	GP	277,875	0.68%	326,862	13.137%	36,506	42,941	(6,436)
6 OPC	Co	16,164,303	39.53%	19,013,950	6.771%	1,094,477	1,287,425	(192,948)
7 WPG	Co	314,520	0.77%	369,968	7.846%	24,676	29,026	(4,350)
8	Sum of Lines 1 to 7	40,891,187	·	48,100,000		2,617,422	3,078,853	(461,432)

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

	<u>APCo</u>	<u>I&M</u>	<u>KPCo</u>	<u>KNGSPT</u>	<u>OPCo</u>	<u>WPCo</u>	AEP East Total
9 Direct Charged PBOP Expense per Actuarial Report	10,991,074	9,836,923	1,994,927	247,734	13,628,228	282,183	36,981,069
10 Additional PBOP Ledger Entries (from Company Records)	(669,581)	(45,394)	-	-	1,105,077	-	
11 Medicare Subsidy	-	-	-	-	-	-	-
12 Net Company Expense (Ln 9 + Ln 10 + Ln 11)	10,321,493	9,791,529	1,994,927	247,734	14,733,305	282,183	37,371,171
13 PBOP Expenses From AEP Service Corporation (from Company Records)	1,038,300	795,128	193,112	30,141	1,430,998	32,337	3,520,016
14 Company PBOP Expense (Ln 12 + Ln 13)	11,359,793	10,586,657	2,188,039	277,875	16,164,303	314,520	40,891,187

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.

OHIO POWER COMPANY

Line No.						Т	ransmission Amount
1	REVENUE REQUIREMENT (w/o incentives)	(In 138)	T ()	A II -			\$281,223,353
2	REVENUE CREDITS	(Note A) (Worksheet E)	Total 9,374,004	DA	1.00000	\$	9,374,004
3	REVENUE REQUIREMENT For All Company Facilities	(In 1 less In 2)				\$	271,849,349
	The Carrying Charge Calculations on lines 6 to 11 belossion Enhancement Charges. The total non-incentive r		-				
4	Revenue Requirement for PJM Schedule 12 Facilities (w/	o incentives) (Worksheet J)	3,768,661	DA	1.00000	\$	3,768,661
5	NET PLANT CARRYING CHARGE w/o intra-AEP charges	s or credits or ROE incentives (Note B)					
6	Annual Rate	((ln 1 - ln 105 - ln 106)/((ln 48 + ln 49 + lr	n 50 + ln 51 + ln 53) x 100))				22.52%
7	Monthly Rate	(ln 6 / 12)					1.88%
8	NET PLANT CARRYING CHARGE ON LINE 6, w/o depr	eciation or ROF incentives (Note R)					
9	Annual Rate	((ln 1 - ln 105 - ln 106 - ln 111 - ln 112) /(((In 48 + In 49 + In 50 + In 51 + In 53) x	100))			18.89%
10	NET PLANT CARRYING CHARGE ON LINE 9, w/o Retui	n, income taxes or ROE incentives (Note B	3)				
11	Annual Rate	((ln 1 - ln 105 - ln 106 - ln 111 - ln 112 - l	,	In 51 + In 53) x 1	00))		8.26%
12	ADDITIONAL REVENUE REQUIREMENT for projects w/	incentive ROE's (Note B) (Worksheet J)					-
13		REVENUE REQUIREMENT FO	R SCHEDULE 1A CHARGES				
14	Total Load Dispatch & Scheduling (Account 561)	Line 85 Below					15,750,749
15	Less: Load Dispatch - Scheduling, System Control and D						8,170,124
16	Less: Load Dispatch - Reliability, Planning & Standards D						1,734,018
17	Total 561 Internally Developed Costs	(Line 14 - Line 15 - Line 16)					5,846,607

OHIO POWER COMPANY

	(1)	(2)	(3)	((4)	(5)
	RATE BASE CALCULATION	Data Sources (See "General Notes")	TO Total	Allo	cator	Total <u>Transmission</u>
Line No.	GROSS PLANT IN SERVICE		NOTE C			
18	Production	(Worksheet A In 1.C)	9,635,707,327	NA	0.00000	_
19	Less: Production ARO (Enter Negative)	(Worksheet A In 2.C)	(156,781,322)	NA	0.00000	-
20	Transmission	(Worksheet A In 3.C & Ln 142)	2,007,735,450	DA		1,948,729,583
21	Less: Transmission ARO (Enter Negative)	(Worksheet A In 4.C& Ln 143)	(3,120)	TP	0.97061	(3,028)
22	Plus: Transmission Plant-in-Service Additions (Work	· · · · · · · · · · · · · · · · · · ·	130,602,038	DA	1.00000	130,602,038
23	Plus: Additional Trans Plant on Transferred Assets (•	<u>-</u>	DA	1.00000	-
24	Distribution	(Worksheet A In 5.C)	3,718,113,471	NA	0.00000	-
25	Less: Distribution ARO (Enter Negative)	(Worksheet A In 6.C)	-	NA W/S	0.00000	46 402 979
26 27	General Plant Less: General Plant ARO (Enter Negative)	(Worksheet A In 7.C) (Worksheet A In 8.C)	243,597,754 (306,041)	W/S W/S	0.06771 0.06771	16,493,878 (20,722)
28	Intangible Plant	(Worksheet A In 9.C)	138,963,972	W/S	0.06771	9,409,178
29	TOTAL GROSS PLANT	(sum Ins 18 to 28)	15,717,629,529	*****	•	2,105,210,927
30	ACCUMULATED DEPRECIATION AND AMORTIZATION	ON				
31	Production Production	(Worksheet A In 12.C)	4,248,263,554	NA	0.00000	_
32	Less: Production ARO (Enter Negative)	(Worksheet A In 13.C)	(83,178,723)	NA	0.00000	-
33	Transmission	(Worksheet A In 14.C & 28.C)	817,203,711	TP1=	0.96845	791,423,913
34	Less: Transmission ARO (Enter Negative)	(Worksheet A In 15.C)	(2,793)	TP1=	0.96845	(2,705)
35	Plus: Transmission Plant-in-Service Additions (Work	sheet I, In 21.I)	1,744,661	DA	1.00000	1,744,661
36	Plus: Additional Projected Deprec on Transferred As	·	-	DA	1.00000	-
37	Plus: Additional Transmission Depreciation for 2013	` '	44,851,117	TP1	0.96845	43,436,228
38	Plus: Additional General & Intangible Depreciation for	· · · · · · · · · · · · · · · · · · ·	26,801,690	W/S	0.06771	1,814,729
39 40	Plus: Additional Accum Deprec on Transferred Asse	·	- 1 201 670 119	DA	1.00000	-
40 41	Distribution Less: Distribution ARO (Enter Negative)	(Worksheet A In 16.C) (Worksheet A In 17.C)	1,391,679,118	NA NA	0.00000 0.00000	-
42	General Plant	(Worksheet A In 18.C)	91,783,557	W/S	0.06771	6,214,617
43	Less: General Plant ARO (Enter Negative)	(Worksheet A In 19.C)	(184,484)	W/S	0.06771	(12,491)
44	Intangible Plant	(Worksheet A In 20.C)	120,774,423	W/S	0.06771	8,177,574
45	TOTAL ACCUMULATED DEPRECIATION	(sum Ins 31 to 44)	6,659,735,831		-	852,796,525
46	NET PLANT IN SERVICE					
47	Production	(ln 18 + ln 19 - ln 31 - ln 32)	5,313,841,174			-
48	Transmission	(ln 20 + ln 21 - ln 33 - ln 34)	1,190,531,412			1,157,305,347
49	Plus: Transmission Plant-in-Service Additions (In 22	,	128,857,377			128,857,377
50 54	Plus: Additional Trans Plant on Transferred Assets	` '	- (44.054.447)			- (42, 426, 220)
51 52	Plus: Additional Transmission Depreciation for 2013 Plus: Additional General & Intangible Depreciation for	,	(44,851,117) (26,801,690)			(43,436,228) (1,814,729)
53	Plus: Additional Accum Deprec on Transferred Asse	· · · · · · · · · · · · · · · · · · ·	(20,801,090)			(1,014,729)
54	Distribution	(ln 24 + ln 25 - ln 40 - ln 41)	2,326,434,353			_
55	General Plant	(ln 26 + ln 27 - ln 42 - ln 43)	151,692,640			10,271,030
56	Intangible Plant	(ln 28 - ln 44)	18,189,549		_	1,231,605
57	TOTAL NET PLANT IN SERVICE	(sum lns 47 to 56)	9,057,893,698		•	1,252,414,402
	DEFENDED TAY AS #10TH 15 TO 5 TO 5 TO 5 TO 5	(1)				
58 50	DEFERRED TAX ADJUSTMENTS TO RATE BASE	(Note D)	(070 057 740)	R I A		
59 60	Account No. 281.1 (enter negative)	(Worksheet B, In 2 & In 5.C)	(376,657,740) (1,764,794,823)	NA DA		(217 244 570)
61	Account No. 282.1 (enter negative) Account No. 283.1 (enter negative)	(Worksheet B, In 7 & In 10.C) (Worksheet B, In 12 & In 15.C)	(604,077,136)	DA		(217,344,579) (20,707,549)
62	Account No. 190.1	(Worksheet B, In 17 & In 20.C)	359,572,801	DA		20,846,170
63	Account No. 255 (enter negative)	(Worksheet B, In 24 & In 25.C)	(322,356)	DA		(191,502)
64	TOTAL ADJUSTMENTS	(sum Ins 59 to 63)	(2,386,279,254)		-	(217,397,460)
65	PLANT HELD FOR FUTURE USE	(Worksheet A In 29.C & In 30.C)	16,588,944	DA		6,002,010
66	REGULATORY ASSETS	(Worksheet A In 36. (C))	-	DA		-
67	WORKING CAPITAL	(Note E)				
68	Cash Working Capital	(1/8 * In 88)	4,227,249			4,103,013
69	Transmission Materials & Supplies	(Worksheet C, In 2.(D))	1,602,775	TP	0.97061	1,555,671
70	A&G Materials & Supplies	(Worksheet C, In 3.(D))	223,854	W/S	0.06771	15,157
71	Stores Expense	(Worksheet C, In 4.(D))	<u> </u>	GP(h)	0.12668	
72 72	Prepayments (Account 165) - Labor Allocated	(Worksheet C, In 6.G)	447,235,548	W/S	0.06771	30,282,087
73 74	Prepayments (Account 165) - Gross Plant Prepayments (Account 165) - Transmission Only	(Worksheet C, In 6.F)	4,444,103	GP(h)	0.12668	562,992
74 75	Prepayments (Account 165) - Transmission Only Prepayments (Account 165) - Unallocable	(Worksheet C, In 6.E) (Worksheet C, In 6.D)	4,940 (433,956,947)	DA NA	1.00000 0.00000	4,940
75 76	TOTAL WORKING CAPITAL	(sum lns 68 to 75)	23,781,522	INC	3.55555	36,523,860
		,		F. A	4.00000	
77	IPP CONTRIBUTIONS FOR CONSTRUCTION	(Note F) (Worksheet D, In 7.B)	(2,464,505)	DA	1.00000	(2,464,505)
78	RATE BASE (sum Ins 57, 64, 65, 66, 76, 77)		6,709,520,405		=	1,075,078,307

OHIO POWER COMPANY

(1) (2) (3) (4) (5)

Lina	EXPENSE, TAXES, RETURN & REVENUE REQUIREMENTS CALCULATION	Data Sources (See "General Notes")	TO Total	Allo	ocator_	Total <u>Transmission</u>
Line	OPERATION & MAINTENANCE EXPENSE					
No. 79	Production	321.80.b	2,425,125,006			
80	Distribution	322.156.b	155,564,708			
	Customer Related Expense					
81	•	322.164,171,178.b	239,467,579			
82	Regional Marketing Expenses	322.131.b	8,466,532			
83	Transmission	321.112.b	52,839,386			
84	TOTAL O&M EXPENSES	(sum lns 79 to 83)	2,881,463,211			
85	Less: Total Account 561	(Note G) (Worksheet F, In 14.C)	15,750,749			
86	Less: Account 565	(Note H) 321.96.b	22,667,784			
87	Less: State Regulatory Deferrals & Amortizations	(Note I) (Worksheet F, In 4.C)	(19,397,139)			
88	Total O&M Allocable to Transmission	(Ins 83 - 85 - 86 - 87)	33,817,992	TP	0.97061	32,824,106
89	Administrative and General	323.197.b (Note J)	159,175,788			
90	Less: Acct. 924, Property Insurance	323.185.b	6,727,215			
91	Acct. 9260039 PBOP Expense	PBOP Worksheet O Line 9 & 10, (Note K)	14,733,305			
92	Acct. 9260057 PBOP Medicare Subsidy	PBOP Worksheet O Line 11, (Note K)	-			
93	PBOP Expense Billed From AEPSC	PBOP Worksheet O Line 13, (Note K)	1,430,998			
94	Acct. 928, Reg. Com. Exp.	323.189.b	1,726,872			
95	Acct. 930.1, Gen. Advert. Exp.	323.191.b	14,095,546			
96	Acct. 930.2, Misc. Gen. Exp.	323.192.b	1,114,296			
97	Balance of A & G	(ln 89 - sum ln 90 to ln 96)	119,347,556	W/S	0.06771	8,080,961
98	Plus: Acct. 924, Property Insurance	(In 90)	6,727,215	GP(h)	0.12668	852,223
		` '	0,727,213			032,223
99	Acct. 928 - Transmission Specific	Worksheet F In 18.(E) (Note L)	-	TP	0.97061	-
100	Acct 930.1 - Only safety related ads -Direct	Worksheet F In 32.(E) (Note L)	-	TP	0.97061	-
101	Acct 930.2 - Misc Gen. Exp Trans	Worksheet F In 39.(E) (Note L)	188,031	DA	1.00000	188,031
102	Settlement Approved PBOP Recovery	PBOP Worksheet O, Col. C, Line 6, (Note M)	19,013,950	W/S	0.06771	1,287,425
103	A & G Subtotal	(sum Ins 97 to 102)	145,276,752			10,408,640
104	O & M EXPENSE SUBTOTAL	(ln 88 + ln 103)	179,094,744		-	43,232,746
105	Plus: TEA Settlement in Account 565	Company Records (Note H)	-	DA	1.00000	<u>-</u>
106	Plus: Transmission Lease Payments To Affiliates in Acc		1,351,836	DA	1.00000	1,351,836
107	TOTAL O & M EXPENSE	(ln 104 + ln 105 + ln 106)	180,446,580	27.	_	44,584,582
			, -,			,,
108	DEPRECIATION AND AMORTIZATION EXPENSE					
109	Production	336.2-6.f	329,291,837	NA	0.00000	-
110	Distribution	336.8.f	94,896,667	NA	0.00000	_
111	Transmission	336.7.f	44,851,117	TP1	0.96845	43,436,228
112	Plus: Transmission Plant-in-Service Additions (Workshe		1,744,661	DA	1.00000	1,744,661
113	General	336.10.f	2,874,916	W/S	0.06771	194,659
			* *			•
114	Intangible	336.1.f	23,926,774	W/S	0.06771	1,620,069
115	TOTAL DEPRECIATION AND AMORTIZATION	(Lns 109+110+111 +112+113+114)	497,585,972			46,995,617
116	TAXES OTHER THAN INCOME	(Note N)				
117	Labor Related					
118	Payroll	Worksheet H In 22.(D)	14,141,746	W/S	0.06771	957,530
119	Plant Related					
120	Property	Worksheet H In 22.(C) & In 46.(C)	214,463,890	DA		55,838,317
121	Gross Receipts/Sales & Use	Worksheet H In 22.(F)	169,923,630	NA	0.00000	
122	Other	Worksheet H In 22.(E)	6,440,495	GP(h)	0.12668	815,900
123	TOTAL OTHER TAXES	(sum Ins 118 to 122)	404,969,761	Oi (ii)	0.12000	57,611,748
120	TOTAL OTTIER TAXES	(34111113 110 to 122)	404,303,701			37,011,740
124	INCOME TAXES	(Note O)				
125	T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =		35.78%			
126	EIT=(T/(1-T)) * (1-(WCLTD/WACC)) =		39.64%			
127	where WCLTD=(In 162) and WACC = (In 165)		00.0 170			
128	and FIT, SIT & p are as given in Note O.					
129	GRCF=1 / (1 - T) = (from In 125)		1.5572			
130	Amortized Investment Tax Credit (enter negative)	(FF1 p.114, ln 19.c)	(1,768,489)			
	, ,					
131	Income Tax Calculation	(ln 126 * ln 134)	234,549,556			37,582,290
132	ITC adjustment	(ln 129 * ln 130)	(2,753,829)	NP(h)	0.12986	(357,606)
133	TOTAL INCOME TAXES	(sum lns 131 to 132)	231,795,728		_	37,224,684
134	RETURN ON RATE BASE (Rate Base * WACC)	(In 78 * In 165)	591,684,933			94,806,722
135	INTEREST ON IPP CONTRIBUTION FOR CONST. (Note	F) (Worksheet D, In 2.(B))	-	DA	1.00000	-
136	(Gains) / Losses on Sales of Plant Held for Future Use (Wo	orksheet N, In 4, Cols. ((F) & (H))	-			-
137	Tax Impact on (Gains) / Losses on Sales of Plant Held for	Future Use (In 136 * In126)	-			-
138	TOTAL REVENUE REQUIREMENT	-	1,906,482,974		_	281,223,353
100	(cum loc 107, 115, 122, 123, 124, 125, 126, 127)	=	1,300,402,314		=	201,223,333

(sum Ins 107, 115, 123, 133, 134, 135, 136, 137)

OHIO POWER COMPANY

SUPPORTING CALCULATIONS

ln								
No.	TRANSMISSION PLANT INCLUDED IN PJM TARIFF							
139	Total transmission plant	(In 20)						2,007,735,450
140	Less transmission plant excluded from PJM Tariff (Note	` ,						· · · · · -
141	Less transmission plant included in OATT Ancillary Servi	•) (Note Q)					59,005,867
142	Transmission plant included in PJM Tariff	(ln 139 - ln 140 - ln 141)	, , ,					1,948,729,583
143	Percent of transmission plant in PJM Tariff	(In 142 / In 139)					TP	0.97061
				Payroll Billed from				
144	WAGES & SALARY ALLOCATOR (W/S)	(Note R)	Direct Payroll	AEP Service Corp.	Total			
145	Production	354.20.b	92,815,544	26,811,434	119,626,978	NA	0.00000	-
146	Transmission	354.21.b	7,208,335	7,788,048	14,996,383	TP	0.97061	14,555,650
147	Regional Market Expenses	354.22.b	0	0	-	NA	0.00000	-
148	Distribution	354.23.b	43,937,892	6,885,956	50,823,848	NA	0.00000	-
149	Other (Excludes A&G)	354.24,25,26.b	15,803,730	13,721,175	29,524,905	NA	0.00000	
150	Total	(sum lns 145 to 149)	159,765,501	55,206,613	214,972,114			14,555,650
151	Transmission related amount						W/S=	0.06771
151 152	Transmission related amount WEIGHTED AVERAGE COST OF CAPITAL (WACC)						W/S=	0.06771 \$
152		(Worksheet L, In. 51, col. (D))					W/S=	\$
	WEIGHTED AVERAGE COST OF CAPITAL (WACC)						W/S= 	
152 153	WEIGHTED AVERAGE COST OF CAPITAL (WACC) Long Term Interest	(Worksheet L, In. 51, col. (D)) (Worksheet L, In. 57, col. (D))					W/S=	\$
152 153 154	WEIGHTED AVERAGE COST OF CAPITAL (WACC) Long Term Interest Preferred Dividends						W/S=	\$
152 153 154 155	WEIGHTED AVERAGE COST OF CAPITAL (WACC) Long Term Interest Preferred Dividends Development of Common Stock:	(Worksheet L, In. 57, col. (D))					W/S=	\$ 216,794,185 -
152 153 154 155 156	WEIGHTED AVERAGE COST OF CAPITAL (WACC) Long Term Interest Preferred Dividends Development of Common Stock: Proprietary Capital	(Worksheet L, In. 57, col. (D)) (FF1 p 112, Ln 16.c)					W/S=	\$ 216,794,185 -
152 153 154 155 156 157	WEIGHTED AVERAGE COST OF CAPITAL (WACC) Long Term Interest Preferred Dividends Development of Common Stock: Proprietary Capital Less: Preferred Stock	(Worksheet L, In. 57, col. (D)) (FF1 p 112, Ln 16.c) (FF1 p 112, Ln 3.c)					W/S=	\$ 216,794,185 - 4,489,200,654 - 2,204,800
152 153 154 155 156 157 158	WEIGHTED AVERAGE COST OF CAPITAL (WACC) Long Term Interest Preferred Dividends Development of Common Stock: Proprietary Capital Less: Preferred Stock Less: Account 216.1	(Worksheet L, In. 57, col. (D)) (FF1 p 112, Ln 16.c) (FF1 p 112, Ln 3.c) (FF1 p 112, Ln 12.c))					\$ 216,794,185 - 4,489,200,654 -
152 153 154 155 156 157 158 159 160	WEIGHTED AVERAGE COST OF CAPITAL (WACC) Long Term Interest Preferred Dividends Development of Common Stock: Proprietary Capital Less: Preferred Stock Less: Account 216.1 Less: Account 219	(Worksheet L, In. 57, col. (D)) (FF1 p 112, Ln 16.c) (FF1 p 112, Ln 3.c) (FF1 p 112, Ln 12.c) (FF1 p 112, Ln 15.c))	Φ.	0/		Cost	\$ 216,794,185 - 4,489,200,654 - 2,204,800 (165,724,552) 4,652,720,406
152 153 154 155 156 157 158 159 160	WEIGHTED AVERAGE COST OF CAPITAL (WACC) Long Term Interest Preferred Dividends Development of Common Stock: Proprietary Capital Less: Preferred Stock Less: Account 216.1 Less: Account 219 Common Stock	(Worksheet L, In. 57, col. (D)) (FF1 p 112, Ln 16.c) (FF1 p 112, Ln 3.c) (FF1 p 112, Ln 12.c) (FF1 p 112, Ln 15.c))	\$	%		Cost (Note S)	\$ 216,794,185 - 4,489,200,654 - 2,204,800 (165,724,552) 4,652,720,406 Weighted
152 153 154 155 156 157 158 159 160	WEIGHTED AVERAGE COST OF CAPITAL (WACC) Long Term Interest Preferred Dividends Development of Common Stock: Proprietary Capital Less: Preferred Stock Less: Account 216.1 Less: Account 219 Common Stock Long Term Debt (Note T) Worksheet L, In 51, col. (B))	(Worksheet L, In. 57, col. (D)) (FF1 p 112, Ln 16.c) (FF1 p 112, Ln 3.c) (FF1 p 112, Ln 12.c) (FF1 p 112, Ln 15.c))	\$ 3,867,825,000	45.39%		Cost	\$ 216,794,185 - 4,489,200,654 - 2,204,800 (165,724,552) 4,652,720,406 Weighted 0.0254
152 153 154 155 156 157 158 159 160 161 162 163	WEIGHTED AVERAGE COST OF CAPITAL (WACC) Long Term Interest Preferred Dividends Development of Common Stock: Proprietary Capital Less: Preferred Stock Less: Account 216.1 Less: Account 219 Common Stock Long Term Debt (Note T) Worksheet L, In 51, col. (B)) Preferred Stock (In 157)	(Worksheet L, In. 57, col. (D)) (FF1 p 112, Ln 16.c) (FF1 p 112, Ln 3.c) (FF1 p 112, Ln 12.c) (FF1 p 112, Ln 15.c))	3,867,825,000	45.39% 0.00%		Cost (Note S) 0.0561	\$ 216,794,185 - 4,489,200,654 - 2,204,800 (165,724,552) 4,652,720,406 Weighted 0.0254 0.0000
152 153 154 155 156 157 158 159 160	WEIGHTED AVERAGE COST OF CAPITAL (WACC) Long Term Interest Preferred Dividends Development of Common Stock: Proprietary Capital Less: Preferred Stock Less: Account 216.1 Less: Account 219 Common Stock Long Term Debt (Note T) Worksheet L, In 51, col. (B))	(Worksheet L, In. 57, col. (D)) (FF1 p 112, Ln 16.c) (FF1 p 112, Ln 3.c) (FF1 p 112, Ln 12.c) (FF1 p 112, Ln 15.c))	<u> </u>	45.39%	_	Cost (Note S)	\$ 216,794,185 - 4,489,200,654 - 2,204,800 (165,724,552) 4,652,720,406 Weighted 0.0254

AEP East Companies

Transmission Cost of Service Formula Rate
Utilizing Historic Cost Data for 2012 and Projected Net Plant at Year-End 2013

OHIO POWER COMPANY

<u>Letter</u> <u>Notes</u>

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

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

See Worksheet E for details.

- B The annual and monthly net plant carrying charges on page 1 are used to compute the revenue requirement for RTEP sponsored upgrades or those projects receiving approved incentive-ROE's.
- C Transmission Plant balances in this study are projected as of December 31, 2013. Other ratebase amounts are as of December 31, 2012.
- The total-company balances shown for Accounts 281, 282, 283, 190 only reflect ADIT that relates to utility operations. The balance of Account 255 is reduced by prior flow throughs and is completely excluded if the utility chose to utilize amortization of tax credits against FIT expense. An exception to this is pre-1971 ITC balances, which are required to be taken as an offset to rate base. Account 281 is not allocated. In compliance with FERC Rulemaking RM02-7-000, Asset Retirement Obligation deferrals have been removed from ratebase. Transmission ADIT allocations are shown on WS B.

The company will not include the ADIT portion of deferred hedge gains and losses in rate base.

- E Cash Working Capital assigned to transmission is one-eighth of O&M allocated to transmission, as shown on line 88. It excludes:
 - 1) Load Scheduling & Dispatch Charges in account 561 that are collected in the OATT Ancilliary Services Revenue, as shown on line 85.
 - 2) AEP transmission equalization transfers, as shown on line 86
 - 3) The impact of state regulatory deferrals and amortizations, as shown on line 87
 - 4) All A&G Expenses, as shown on line 103.
- Consistent with Paragraph 657 of Order 2003-A, the amount on line 77 is equal to the balance of IPP System Upgrade Credits owed to transmission customers that made contributions toward the construction of System upgrades, and includes accrued interest and unreturned balance of contributions. The annual interest expense is included on line 135.
- Removes from the cost of service the Load Scheduling and Dispatch expenses booked to accounts 561.1 through 561.8. Expenses recorded in these accounts, with the exception of 561.4 & 561.8 (lines 15 & 16 above) are recovered in Schedule 1A, OATT ancillary services rates. See Worksheet F, lines 5 through 14, for descriptions and the Form 1 Source of these accounts' balances.
- Removes cost of transmission service provided by others to determine the basis of cash working capital on line 88. To the extent such service is incurred to provide the PJM service at issue, e.g. transmission equalization agreement, such costs are added back on lines 105 and 106 to determine the total O&M collected in the formula. The amounts on lines 105 and 106 are also excluded in the calculation of the FCR percentage calculated on lines 5 through 11.

 The addbacks on lines 105 and 106 of activity recorded in 565 represents inter-company sales or purchases of transmission capacity necessary to meet each AEP

company's transmission load relative to their available transmission capacity.

The company records referenced on lines 105 and 106 is the OHIO POWER COMPANY general ledger.

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

(ln 130) multiplied by (1/1-T). If the applicable tax rates are zero enter 0.

- J General Plant and Administrative & General expenses, other than in accounts 924, 928, and 930, will be functionalized based on the Wages & Salaries "W/S" allocator. The allocation basis for accounts 924, 928 and 930 are separately presented in the formula. A change in the allocation method for an account must be approved via a 205 filing with the FERC.
- These deductions on lines 91 through 93 are to remove from the cost of service the expenses recorded by the company for Postemployment Benefits Other than Pensions (PBOP). See Note M below for the recoverable PBOP expense.
- Expenses reported for these A&G accounts will be included in the cost of service only to the extent they are directly assignable to transmission service. Worksheet F allocates these expense items. Acct 928 Includes Regulatory Commission expenses itemized in FERC Form-1 at page 351, column H. FERC Assessment Fees and Annual Charges shall not be allocated to transmission. Only safety-related and educational advertising costs in Account 930.1 are included in the TCOS. Account 930.2 includes the expenses incurred by the transmission function for Associated Business Development revenues given as a credit to the TCOS on Worksheet E.
- See note K above. Per the settlement in Docket ER08-1329, recoverable PBOP expense is based on an annual total for the operating companies that is ratioed to them based on the total of actual annual PBOP costs, including charges from the AEP Service Corportation. The calculation of the recoverable amount for each company is shown on Worksheet O, and the process for updating the annual total is documented on Attachment F, Allowable PBOP Expense Formula.
- N Includes only FICA, unemployment, highway, property and other assessments charged in the current year. Gross receipts, sales & use and taxes related to income are excluded.
- O The currently effective income tax rate, where FIT is the Federal income tax rate; SIT is the State income tax rate, and p = the percentage of federal income tax deductible for state income taxes. See Worksheet G for the development of the Company's composite SIT. A utility that elected to utilize amortization of tax credits against taxable income, rather than book tax credits to Account No. 255 and reduce rate base, must reduce its income tax expense by the amount of the Amortized Investment Tax Credit (Form 1, 266.8.f)

Inputs Required: FIT = 35.00%

SIT= 1.20% (State Income Tax Rate or Composite SIT. Worksheet G))
p = 0.00% (percent of federal income tax deductible for state purposes)

- P Removes plant excluded from the OATT because it does not meet the PJM's definition of Transmission Facilities or is otherwise ineligible to be recovered under the OATT.
- Q Removes transmission plant (e.g. step-up transformers) included in the development of OATT ancillary service rates and not already removed for reasons indicated in Note P.
- R Includes functional wages & salaries billed by AEP Service Corporation for support of the operating company.
- Long Term Debt cost rate = long-term interest (ln 153) / long term debt (ln 162). Preferred Stock cost rate = preferred dividends (ln 154) / preferred outstanding (ln 163). Common Stock cost rate (ROE) = 11.49%, the rate accepted by FERC in Docket No. ER08-1329. It includes an additional 50 basis points for PJM RTO membership. In the Projected & Historic templates, the interest expense on long-term debt is the sum of a full year's interest expense at the coupon rate for each issuance outstanding as of December 31 of the historic year. The projected expense for variable rate debt will be based on the effective rate at December 31. These conventions ensure that the expense used in the projection will reflect a full year, similar to the actual expense that will appear in the subsequent true-up of the projection, and minimize the impact on the true-up of using a partial year interest expense. The projection will reflect the actual historic-year expense recorded for issuance expenses, discounts and premiums, and gains or losses on reacquired debt. Eligible hedging gains or losses will be limited to five basis points of the projected capital structure. Details and calculations are shown on Worksheet L.
- This note only applies to Indiana Michigan Power Company.
- U This note only applies to the true-up template.

AEP East Companies Transmission Cost of Service Formula Rate Utilizing Historic Cost Data for 2012 with Year-End Rate Base Balances

OHIO POWER COMPANY

Line No.						Tı	ransmission Amount
166	REVENUE REQUIREMENT (w/o incentives)	(In 303)					\$269,183,096
167	REVENUE CREDITS	(Note A) (Worksheet E)	Total 9,374,004	Allocator DA	1.00000	\$	9,374,004
168	REVENUE REQUIREMENT For All Company Facilities	(In 166 less In 167)				\$	259,809,092
	The Carrying Charge Calculations on lines 171 to 176 lement Charges. The total non-incentive revenue requir	— · · · ·		nedule 12, Transmission			
169	Not applicable on this template						
170	NET PLANT CARRYING CHARGE w/o intra-AEP charge						
171 172	Annual Rate Monthly Rate	((ln 166 - ln 270 - ln 271)/ ln 213 x 100) (ln 171 / 12)					23.14% 1.93%
		,					
173 174	NET PLANT CARRYING CHARGE ON LINE 171, w/o d	epreciation or ROE incentives (Note B) ((In 166 - In 270 - In 271 - In 276) / In 213 x 1	00)				19.39%
		,	•				
175 176	NET PLANT CARRYING CHARGE ON LINE 174, w/o Re Annual Rate	eturn, income taxes or ROE incentives (Note B) ((In 166 - In 270 - In 271 - In 276 - In 298 - In					8.87%
177	Not applicable on this template		,				
178		REVENUE REQUIREME	NT FOR SCHEDULE 1A CHARGES				
179	Total Load Dispatch & Scheduling (Account 561)	Line 250 Below					15,750,749
180	Less: Load Dispatch - Scheduling, System Control and I	Dispatch Services (321.88.b)					8,170,124
181	Less: Load Dispatch - Reliability, Planning & Standards	Development Services (321.92.b)					1,734,018
182	Total 561 Internally Developed Costs	(Line 179 - Line 180 - Line 181)					5,846,607

(5)

AEP East Companies Transmission Cost of Service Formula Rate Utilizing Historic Cost Data for 2012 with Year-End Rate Base Balances

OHIO POWER COMPANY

(1) (2) (3)

		Data Sources				Total
Line	RATE BASE CALCULATION	(See "General Notes")	TO Total NOTE C	<u>Allocator</u>		<u>Transmission</u>
No.	GROSS PLANT IN SERVICE		<u></u>			
183	Production	(Worksheet A In 1.C)	9,635,707,327	NA	0.00000	-
184	Less: Production ARO (Enter Negative)	(Worksheet A In 2.C)	(156,781,322)	NA	0.00000	-
185	Transmission	(Worksheet A In 3.C & Ln 307)	2,007,735,450	DA		1,948,729,583
186	Less: Transmission ARO (Enter Negative)	(Worksheet A In 4.C& Ln 308)	(3,120)	TP	0.97061	(3,028)
187	Plus: Transmission Plant-in-Service Additions (Wor	rksheet I)	N/A	NA	0.00000	N/A
188	Plus: Additional Trans Plant on Transferred Assets	(Worksheet I)	N/A	NA	0.00000	N/A
189	Distribution	(Worksheet A In 5.C)	3,718,113,471	NA	0.00000	-
190	Less: Distribution ARO (Enter Negative)	(Worksheet A In 6.C)	-	NA	0.00000	-
191	General Plant	(Worksheet A In 7.C)	243,597,754	W/S	0.06771	16,493,878
192	Less: General Plant ARO (Enter Negative)	(Worksheet A In 8.C)	(306,041)	W/S	0.06771	(20,722)
193	Intangible Plant	(Worksheet A In 9.C)	138,963,972	W/S	0.06771	9,409,178
194	TOTAL GROSS PLANT	(sum Ins 183 to 193)	15,587,027,491	GP(h)= GTD=	0.126683 0.34034	1,974,608,889
195	ACCUMULATED DEPRECIATION AND AMORTIZATION	ON		0.5=	0.0.00	
196	Production	(Worksheet A In 12.C)	4,248,263,554	NA	0.00000	-
197	Less: Production ARO (Enter Negative)	(Worksheet A In 13.C)	(83,178,723)	NA	0.00000	-
198	Transmission	(Worksheet A In 14.C & 28.C)	817,203,711	TP1=	0.96845	791,423,913
199	Less: Transmission ARO (Enter Negative)	(Worksheet A In 15.C)	(2,793)	TP1=	0.96845	(2,705)
200	Plus: Transmission Plant-in-Service Additions (Wor	,	N/A	DA	1.00000	N/A
201	Plus: Additional Projected Deprec on Transferred A	ssets (Worksheet I)	N/A	DA	1.00000	N/A
202	Plus: Additional Transmission Depreciation for 2013	·	N/A	TP1	0.96845	N/A
203	Plus: Additional General & Intangible Depreciation f		N/A	W/S	0.06771	N/A
204	Plus: Additional Accum Deprec on Transferred Ass	,	N/A	DA	1.00000	N/A
205	Distribution	(Worksheet A In 16.C)	1,391,679,118	NA	0.00000	-
206	Less: Distribution ARO (Enter Negative)	(Worksheet A In 17.C)	- -	NA	0.00000	-
207	General Plant	(Worksheet A In 18.C)	91,783,557	W/S	0.06771	6,214,617
208	Less: General Plant ARO (Enter Negative)	(Worksheet A In 19.C)	(184,484)	W/S	0.06771	(12,491)
209	Intangible Plant	(Worksheet A In 20.C)	120,774,423_	W/S	0.06771	8,177,574
210	TOTAL ACCUMULATED DEPRECIATION	(sum Ins 196 to 209)	6,586,338,363			805,800,907
211	NET PLANT IN SERVICE					
212	Production	(In 183 + In 184 - In 196 - In 197)	5,313,841,174			-
213	Transmission	(In 185 + In 186 - In 198 - In 199)	1,190,531,412			1,157,305,347
214	Plus: Transmission Plant-in-Service Additions (In 18	87 - In 200)	N/A			N/A
215	Plus: Additional Trans Plant on Transferred Assets	(In 188 - In 201)	N/A			N/A
216	Plus: Additional Transmission Depreciation for 2013	3 (-ln 202)	N/A			N/A
217	Plus: Additional General & Intangible Depreciation f	for 2013 (-In 203)	N/A			N/A
218	Plus: Additional Accum Deprec on Transferred Ass	ets (Worksheet I) (-In 204)	N/A			N/A
219	Distribution	(In 189 + In 190 - In 205 - In 206)	2,326,434,353			-
220	General Plant	(In 191 + In 192 - In 207 - In 208)	151,692,640			10,271,030
221	Intangible Plant	(In 193 - In 209)	18,189,549			1,231,605
222	TOTAL NET PLANT IN SERVICE	(sum lns 212 to 221)	9,000,689,128	NP(h)=	0.129858	1,168,807,982
000		(Note D)				
223 224	DEFERRED TAX ADJUSTMENTS TO RATE BASE Account No. 281.1 (enter negative)	(Note D) (Worksheet B, In 2 & In 5.C)	(376,657,740)	NA		
224 225	,	(Worksheet B, In 7 & In 10.C)	(1,764,794,823)	DA		(217 244 570)
226	Account No. 282.1 (enter negative) Account No. 283.1 (enter negative)	(Worksheet B, In 12 & In 15.C)	(604,077,136)	DA		(217,344,579) (20,707,549)
227	Account No. 190.1	(Worksheet B, In 17 & In 20.C)	359,572,801	DA		20,846,170
228	Account No. 255 (enter negative)	(Worksheet B, In 24 & In 25.C)	(322,356)	DA		(191,502)
229	TOTAL ADJUSTMENTS	(sum lns 224 to 228)	(2,386,279,254)	D/ ((217,397,460)
230	PLANT HELD FOR FUTURE USE	(Worksheet A In 29.C & In 30.C)	16,588,944	DA		6,002,010
231	REGULATORY ASSETS	(Worksheet A In 36. (C))	-	DA		-
232	WORKING CAPITAL	(Note E)				
233	Cash Working Capital	(1/8 * In 253)	4,227,249			4,103,013
234	Transmission Materials & Supplies	(Worksheet C, In 2.(D))	1,602,775	TP	0.97061	1,555,671
235	A&G Materials & Supplies	(Worksheet C, In 3.(D))	223,854	W/S	0.06771	15,157
236	Stores Expense	(Worksheet C, In 4.(D))	· -	GP(h)	0.12668	-
237	Prepayments (Account 165) - Labor Allocated	(Worksheet C, In 6.G)	447,235,548	W/S	0.06771	30,282,087
238	Prepayments (Account 165) - Gross Plant	(Worksheet C, In 6.F)	4,444,103	GP(h)	0.12668	562,992
239	Prepayments (Account 165) - Transmission Only	(Worksheet C, In 6.E)	4,940	DA	1.00000	4,940
240	Prepayments (Account 165) - Unallocable	(Worksheet C, In 6.D)	(433,956,947)	NA	0.00000	
241	TOTAL WORKING CAPITAL	(sum Ins 233 to 240)	23,781,522			36,523,860
242	IPP CONTRIBUTIONS FOR CONSTRUCTION	(Note F) (Worksheet D, In 7.B)	(2,464,505)	DA	1.00000	(2,464,505)
243	RATE BASE (sum Ins 222, 229, 230, 231, 241, 242)		6,652,315,835			991,471,886
_ 10	27.02 (0000 110 222, 220, 200, 201, 271, 272)		5,552,510,000			

(5)

AEP East Companies Transmission Cost of Service Formula Rate Utilizing Historic Cost Data for 2012 with Year-End Rate Base Balances

OHIO POWER COMPANY

(1) (2) (3)

Line	EXPENSE, TAXES, RETURN & REVENUE REQUIREMENTS CALCULATION	Data Sources (See "General Notes")	TO Total	<u>Allocator</u>		Total <u>Transmission</u>
No.	OPERATION & MAINTENANCE EXPENSE					
244	Production	321.80.b	2,425,125,006			
245	Distribution	322.156.b	155,564,708			
246	Customer Related Expense	322 & 323.164,171,178.b	239,467,579			
247 248	Regional Marketing Expenses Transmission	322.131.b 321.112.b	8,466,532 52,839,386			
249	TOTAL O&M EXPENSES	(sum Ins 244 to 248)	2,881,463,211			
250	Less: Total Account 561	(Note G) (Worksheet F, In 14.C)	15,750,749			
251	Less: Account 565	(Note H) 321.96.b	22,667,784			
252	Less: Regulatory Deferrals & Amortizations Total O&M Allocable to Transmission	(Note I) (Worksheet F, In 4.C) (Ins 248 - 250 - 251 - 252)	(19,397,139) 33,817,992	TP	0.97061	22 024 406
253	Total Oalvi Allocable to Transmission	(115 246 - 250 - 251 - 252)	33,617,992	IP .	0.97061	32,824,106
254	Administrative and General	323.197.b (Note J)	159,175,788			
255	Less: Acct. 924, Property Insurance	323.185.b	6,727,215			
256	Acct. 9260039 PBOP Expense	PBOP Worksheet O Line 9 & 10, (Note K)	14,733,305			
257 258	Acct. 9260057 PBOP Medicare Subsidy PBOP Expense Billed From AEPSC	PBOP Worksheet O Line 11, (Note K) PBOP Worksheet O Line 13, (Note K)	1,430,998			
259	Acct. 928, Reg. Com. Exp.	323.189.b	1,726,872			
260	Acct. 930.1, Gen. Advert. Exp.	323.191.b	14,095,546			
261	Acct. 930.2, Misc. Gen. Exp.	323.192.b	1,114,296			
262	Balance of A & G	(ln 254 - sum ln 255 to ln 261)	119,347,556	W/S	0.06771	8,080,961
263	Plus: Acct. 924, Property Insurance	(In 255)	6,727,215	GP(h)	0.12668	852,223
264 265	Acct. 928 - Transmission Specific Acct 930.1 - Only safety related ads -Direct	Worksheet F In 18.(E) (Note L) Worksheet F In 32.(E) (Note L)		TP TP	0.97061 0.97061	-
266	Acct 930.1 - Only safety related ads -bliect Acct 930.2 - Misc Gen. Exp Trans	Worksheet F In 39.(E) (Note L)	188,031	DA	1.00000	188,031
267	Settlement Approved PBOP Recovery	PBOP Worksheet O, Col. C, Line 6, (Note M)	19,013,950	W/S	0.06771	1,287,425
268	A & G Subtotal	(sum Ins 262 to 267)	145,276,752			10,408,640
269	O & M EXPENSE SUBTOTAL	(ln 253 + ln 268)	179,094,744	DA	4 00000	43,232,746
270 271	Plus: TEA Settlement in Account 565 Plus: Transmission Lease Payments To Affiliates in Account 565	Company Records (Note H)	1,351,836	DA DA	1.00000 1.00000	- 1,351,836
272	TOTAL O & M EXPENSE	(ln 269 + ln 270 + ln 271)	180,446,580	D/(1.00000	44,584,582
		(00 +1 0 +1 1)				,00 .,00=
273	DEPRECIATION AND AMORTIZATION EXPENSE					
274	Production	336.2-6.f	329,291,837	NA NA	0.00000	-
275 276	Distribution Transmission	336.8.f 336.7.f	94,896,667 44,851,117	NA TP1	0.00000 0.96845	- 43,436,228
277	Plus: Transmission Plant-in-Service Additions (Worksh		N/A		0.50045	N/A
278	General	336.10.f	2,874,916	W/S	0.06771	194,659
279	Intangible	336.1.f	23,926,774	W/S	0.06771	1,620,069
280	TOTAL DEPRECIATION AND AMORTIZATION	(Ln 274+275+	495,841,311			45,250,956
281	TAXES OTHER THAN INCOME	276+277+278+279) (Note N)				
282	Labor Related	(Note IV)				
283	Payroll	Worksheet H In 22.(D)	14,141,746	W/S	0.06771	957,530
284	Plant Related					
285	Property	Worksheet H In 22.(C) & In 46.(C)	214,463,890	DA NA	0.00000	55,838,317
286 287	Gross Receipts/Sales & Use Other	Worksheet H In 22.(F) Worksheet H In 22.(E)	169,923,630 6,440,495	NA GP(h)	0.00000 0.12668	- 815,900
288	TOTAL OTHER TAXES	(sum Ins 283 to 287)	404,969,761	Or (II)	0.12000	57,611,748
		()	7,557			- ,- , -
289	INCOME TAXES	(Note O)				
290	T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =		35.78%			
291 292	EIT=(T/(1-T)) * (1-(WCLTD/WACC)) = where WCLTD=(In 327) and WACC = (In 330)		39.64%			
293	and FIT, SIT & p are as given in Note O.					
294	GRCF=1 / (1 - T) = (from In 290)		1.5572			
295	Amortized Investment Tax Credit (enter negative)	(FF1 p.114, ln 19.c)	(1,768,489)			
200	Income Tay Calculation	(la 204 * la 200)	222 540 045			24 650 600
296 297	Income Tax Calculation ITC adjustment	(In 291 * In 299) (In 294 * In 295)	232,549,815 (2,753,829)	NP(h)	0.12986	34,659,600 (357,606)
298	TOTAL INCOME TAXES	(sum Ins 296 to 297)	229,795,986	(1)	5.12500	34,301,994
		,				, ,
299	RETURN ON RATE BASE (Rate Base*WACC)	(In 243 * In 330)	586,640,298			87,433,817
300	INTEREST ON IPP CONTRIBUTION FOR CONST. (Note	F) (Worksheet D, In 2.(B))	-	DA	1.00000	-
301	(Gains) / Losses on Sales of Plant Held for Future Use (W	Vorksheet N, In 4, Cols. ((F) & (H))	-			-
302	Tax Impact on Net Loss / (Gain) on Sales of Plant Held for	or Future Use (In 301 * In291)	-			-
303	TOTAL REVENUE REQUIREMENT		1,897,693,936			269,183,096
	(sum Ins 272, 280, 288, 298, 299, 300, 301, 302)					<u> </u>

AEP East Companies Transmission Cost of Service Formula Rate Utilizing Historic Cost Data for 2012 with Year-End Rate Base Balances

OHIO POWER COMPANY

SUPPORTING CALCULATIONS

ln								
No.	TRANSMISSION PLANT INCLUDED IN PJM TARIFF							
304	Total transmission plant	(In 185)						2,007,735,450
305	Less transmission plant excluded from PJM Tariff (Note	•						
306	Less transmission plant included in OATT Ancillary Serv		C)) (Note Q)				<u> </u>	59,005,867
307	Transmission plant included in PJM Tariff	(In 304 - In 305 - In 306)						1,948,729,583
308	Percent of transmission plant in PJM Tariff	(In 307 / In 304)					TP=	0.97061
				Payroll Billed from				
309	WAGES & SALARY ALLOCATOR (W/S)	(Note R)	Direct Payroll	AEP Service Corp.	Total			
310	Production	354.20.b	92,815,544	26,811,434	119,626,978	NA	0.00000	-
311	Transmission	354.21.b	7,208,335	7,788,048	14,996,383	TP	0.97061	14,555,650
312	Regional Market Expenses	354.22.b	0	0	-	NA	0.00000	-
313	Distribution	354.23.b	43,937,892	6,885,956	50,823,848	NA	0.00000	-
314	Other (Excludes A&G)	354.24,25,26.b	15,803,730	13,721,175	29,524,905	NA	0.00000	<u>-</u>
315	Total	(sum Ins 310 to 314)	159,765,501	55,206,613	214,972,114			14,555,650
316	Transmission related amount						W/S=	0.06771
							W/S=	0.06771 \$
317	WEIGHTED AVERAGE COST OF CAPITAL (WACC)	(Worksheet L In 51 col (D))					W/S= 	\$
317 318	WEIGHTED AVERAGE COST OF CAPITAL (WACC) Long Term Interest	(Worksheet L, In. 51, col. (D))					W/S= _	\$ 216,794,185
317 318 319	WEIGHTED AVERAGE COST OF CAPITAL (WACC) Long Term Interest Preferred Dividends	(Worksheet L, In. 51, col. (D)) (Worksheet L, In. 57, col. (D))					W/S= _	\$
317 318 319 320	WEIGHTED AVERAGE COST OF CAPITAL (WACC) Long Term Interest Preferred Dividends Development of Common Stock:	(Worksheet L, In. 57, col. (D))					W/S= _	\$ 216,794,185 -
317 318 319 320 321	WEIGHTED AVERAGE COST OF CAPITAL (WACC) Long Term Interest Preferred Dividends Development of Common Stock: Proprietary Capital	(Worksheet L, In. 57, col. (D)) (FF1 p 112, Ln 16.c)					W/S=	\$
317 318 319 320 321 322	WEIGHTED AVERAGE COST OF CAPITAL (WACC) Long Term Interest Preferred Dividends Development of Common Stock: Proprietary Capital Less: Preferred Stock	(Worksheet L, In. 57, col. (D)) (FF1 p 112, Ln 16.c) (FF1 p 112, Ln 3.c)					W/S=	\$ 216,794,185 - 4,489,200,654 -
317 318 319 320 321 322 323	WEIGHTED AVERAGE COST OF CAPITAL (WACC) Long Term Interest Preferred Dividends Development of Common Stock: Proprietary Capital Less: Preferred Stock Less: Account 216.1	(Worksheet L, In. 57, col. (D)) (FF1 p 112, Ln 16.c) (FF1 p 112, Ln 3.c) (FF1 p 112, Ln 12.c)					W/S≡	\$ 216,794,185 - 4,489,200,654 - 2,204,800
317 318 319 320 321 322	WEIGHTED AVERAGE COST OF CAPITAL (WACC) Long Term Interest Preferred Dividends Development of Common Stock: Proprietary Capital Less: Preferred Stock	(Worksheet L, In. 57, col. (D)) (FF1 p 112, Ln 16.c) (FF1 p 112, Ln 3.c)	4)				W/S=	\$ 216,794,185 - 4,489,200,654 -
317 318 319 320 321 322 323 324 325	WEIGHTED AVERAGE COST OF CAPITAL (WACC) Long Term Interest Preferred Dividends Development of Common Stock: Proprietary Capital Less: Preferred Stock Less: Account 216.1 Less: Account 219	(Worksheet L, In. 57, col. (D)) (FF1 p 112, Ln 16.c) (FF1 p 112, Ln 3.c) (FF1 p 112, Ln 12.c) (FF1 p 112, Ln 15.c)	4)				Cost	\$ 216,794,185 - 4,489,200,654 - 2,204,800 (165,724,552) 4,652,720,406
317 318 319 320 321 322 323 324 325	WEIGHTED AVERAGE COST OF CAPITAL (WACC) Long Term Interest Preferred Dividends Development of Common Stock: Proprietary Capital Less: Preferred Stock Less: Account 216.1 Less: Account 219 Common Stock	(Worksheet L, In. 57, col. (D)) (FF1 p 112, Ln 16.c) (FF1 p 112, Ln 3.c) (FF1 p 112, Ln 12.c) (FF1 p 112, Ln 15.c)	4)	\$	%		Cost (Note S)	\$ 216,794,185 - 4,489,200,654 - 2,204,800 (165,724,552) 4,652,720,406 Weighted
317 318 319 320 321 322 323 324 325	WEIGHTED AVERAGE COST OF CAPITAL (WACC) Long Term Interest Preferred Dividends <u>Development of Common Stock:</u> Proprietary Capital Less: Preferred Stock Less: Account 216.1 Less: Account 219 Common Stock Long Term Debt (Note T) Worksheet L, In 51, col. (B))	(Worksheet L, In. 57, col. (D)) (FF1 p 112, Ln 16.c) (FF1 p 112, Ln 3.c) (FF1 p 112, Ln 12.c) (FF1 p 112, Ln 15.c)	4)	\$ 3,867,825,000	45.39%		Cost	\$ 216,794,185 - 4,489,200,654 - 2,204,800 (165,724,552) 4,652,720,406 Weighted 0.0254
317 318 319 320 321 322 323 324 325 326 327 328	WEIGHTED AVERAGE COST OF CAPITAL (WACC) Long Term Interest Preferred Dividends Development of Common Stock: Proprietary Capital Less: Preferred Stock Less: Account 216.1 Less: Account 219 Common Stock Long Term Debt (Note T) Worksheet L, In 51, col. (B)) Preferred Stock (In 322)	(Worksheet L, In. 57, col. (D)) (FF1 p 112, Ln 16.c) (FF1 p 112, Ln 3.c) (FF1 p 112, Ln 12.c) (FF1 p 112, Ln 15.c)	4)	3,867,825,000	45.39% 0.00%		Cost (Note S) 0.0561	\$ 216,794,185 - 4,489,200,654 - 2,204,800 (165,724,552) 4,652,720,406 Weighted 0.0254 0.0000
317 318 319 320 321 322 323 324 325	WEIGHTED AVERAGE COST OF CAPITAL (WACC) Long Term Interest Preferred Dividends <u>Development of Common Stock:</u> Proprietary Capital Less: Preferred Stock Less: Account 216.1 Less: Account 219 Common Stock Long Term Debt (Note T) Worksheet L, In 51, col. (B))	(Worksheet L, In. 57, col. (D)) (FF1 p 112, Ln 16.c) (FF1 p 112, Ln 3.c) (FF1 p 112, Ln 12.c) (FF1 p 112, Ln 15.c)	4)	·	45.39%		Cost (Note S)	\$ 216,794,185 - 4,489,200,654 - 2,204,800 (165,724,552) 4,652,720,406 Weighted 0.0254

AEP East Companies Transmission Cost of Service Formula Rate Utilizing Historic Cost Data for 2012 with Year-End Rate Base Balances

OHIO POWER COMPANY

<u>Letter</u> <u>Notes</u>

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

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

See Worksheet E for details.

В

G

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

- C Transmission Plant balances in this study are historic as of December 31, 2012.
- The total-company balances shown for Accounts 281, 282, 283, 190 only reflect ADIT that relates to utility operations. The balance of Account 255 is reduced by prior flow throughs and is completely excluded if the utility chose to utilize amortization of tax credits against FIT expense. An exception to this is pre-1971 ITC balances, which are required to be taken as an offset to rate base. Account 281 is not allocated. In compliance with FERC Rulemaking RM02-7-000, Asset Retirement Obligation deferrals have been removed from ratebase. Transmission ADIT allocations are shown on WS B.

 The company will not include the ADIT portion of deferred hedge gains and losses in rate base.
- E Cash Working Capital assigned to transmission is one-eighth of O&M allocated to transmission, as shown on line 253. It excludes:
 - 1) Load Scheduling & Dispatch Charges in account 561 that are collected in the OATT Ancilliary Services Revenue, as shown on line 250.
 - 2) AEP transmission equalization transfers, as shown on line 251
 - 3) The impact of state regulatory deferrals and amortizations, as shown on line 252
 - 4) All A&G Expenses, as shown on line 268.
- F Consistent with Paragraph 657 of Order 2003-A, the amount on line 242 is equal to the balance of IPP System Upgrade Credits owed to transmission customers that made contributions toward the construction of System upgrades, and includes accrued interest and unreturned balance of contributions. The annual interest expense is included on line 300.
 - Removes from the cost of service the Load Scheduling and Dispatch expenses booked to accounts 561.1 through 561.8. Expenses recorded in these accounts, with the exception of 561.4 & 561.8 (lines 180 & 181 above) are recovered in Schedule 1A, OATT ancillary services rates. See Worksheet F, lines 5 through 14, for descriptions and the Form 1 Source of these accounts' balances.
- Removes cost of transmission service provided by others to determine the basis of cash working capital on line 253. To the extent such service is incurred to provide the PJM service at issue, e.g. transmission equalization agreement, such costs are added back on lines 270 and 271 to determine the total O&M collected in the formula. The amounts on lines 270 and 271 are also excluded in the calculation of the FCR percentage calculated on lines 170 through 176.
 - The addbacks on lines 270 and 271 of activity recorded in 565 represents inter-company sales or purchases of transmission capacity necessary to meet each AEP company's transmission load relative to their available transmission capacity.

The company records referenced on lines 270 and 271 is the OHIO POWER COMPANY general ledger.

- I Removes the impact of state regulatory deferrals or their amortization from O&M expense.
 - General Plant and Administrative & General expenses, other than in accounts 924, 928, and 930, will be functionalized based on the Wages & Salaries "W/S" allocator. The allocation basis for accounts 924, 928 and 930 are separately presented in the formula. A change in the allocation method for an account must be approved via a 205 filing with the FERC.
- These deductions on lines 256 through 258 are to remove from the cost of service the expenses recorded by the company for Postemployment Benefits Other than Pensions (PBOP). See Note M below for the recoverable PBOP expense.
- Expenses reported for these A&G accounts will be included in the cost of service only to the extent they are directly assignable to transmission service. Worksheet F allocates these expense items. Acct 928 Includes Regulatory Commission expenses itemized in FERC Form-1 at page 351, column H. FERC Assessment Fees and Annual Charges shall not be allocated to transmission. Only safety-related and educational advertising costs in Account 930.1 are included in the TCOS. Account 930.2 includes the expenses incurred by the transmission function for Associated Business Development revenues given as a credit to the TCOS on Worksheet E.
- M See note K above. Per the settlement in Docket ER08-1329, recoverable PBOP expense is based on an annual total for the operating companies that is ratioed to them based on the total of actual annual PBOP costs, including charges from the AEP Service Corportation. The calculation of the recoverable amount for each company is shown on Worksheet O, and the process for updating the annual total is documented on Attachment F, Allowable PBOP Expense Formula.
- N Includes only FICA, unemployment, highway, property and other assessments charged in the current year. Gross receipts, sales & use and taxes related to income are excluded.
- The currently effective income tax rate, where FIT is the Federal income tax rate; SIT is the State income tax rate, and p = the percentage of federal income tax deductible for state income taxes. See Worksheet G for the development of the Company's composite SIT.

 A utility that elected to utilize amortization of tax credits against taxable income, rather than book tax credits to Account No. 255 and reduce rate base, must reduce its income tax expense by the amount of the Amortized Investment Tax Credit (Form 1, 266.8.f)

 (In 295) multiplied by (1/1-T). If the applicable tax rates are zero enter 0.

Inputs Required: FIT = 35.00%SIT= 1.20% (State Income Tax Rate or Composite SIT. Worksheet G)) p = 0.00% (percent of federal income tax deductible for state purposes)

- P Removes plant excluded from the OATT because it does not meet the PJM's definition of Transmission Facilities or is otherwise ineligible to be recovered under the OATT.
- Q Removes transmission plant (e.g. step-up transformers) included in the development of OATT ancillary service rates and not already removed for reasons indicated in Note P.
- R Includes functional wages & salaries billed by AEP Service Corporation for support of the operating company.
- S Long Term Debt cost rate = long-term interest (ln 318) / long term debt (ln 327). Preferred Stock cost rate = preferred dividends (ln 319) / preferred outstanding (ln 328). Common Stock cost rate (ROE) = 11.49%, the rate accepted by FERC in Docket No. ER08-1329. It includes an additional 50 basis points for remaining a member of the PJM RTO.

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

- This note only applies to Indiana Michigan Power Company.
- U This note only applies to the true-up template.

OHIO POWER COMPANY

Line No.						Т	ransmission Amount
1	REVENUE REQUIREMENT (w/o incentives)	(In 138)	Tatal	Α.ΙΙ			\$262,126,968
2	REVENUE CREDITS	(Note A) (Worksheet E)	Total 9,374,004	DA	1.00000	\$	9,374,004
3	REVENUE REQUIREMENT For All Company Facilities	(In 1 less In 2)				\$	252,752,964
	The Carrying Charge Calculations on lines 6 to 11 belo smission Enhancement Charges. The total non-incenti		_				
4	Revenue Requirement for PJM Schedule 12 Facilities (w	//o incentives) (Worksheet K)	1,248,552	DA	1.00000	\$	1,248,552
5 6 7	NET PLANT CARRYING CHARGE w/o intra-AEP charge Annual Rate Monthly Rate	es or credits or ROE incentives (Note B) ((In 1 - In 105 - In 106)/ In 48 x 100) (In 6 / 12)					22.95% 1.91%
8 9	NET PLANT CARRYING CHARGE ON LINE 6, w/o depr Annual Rate	reciation or ROE incentives (Note B) ((In 1 - In 105 - In 106 - In 111) / In 48 x 100	0)				19.12%
10 11	NET PLANT CARRYING CHARGE ON LINE 9, w/o Return Annual Rate	rn, income taxes or ROE incentives (Note B) ((In 1 - In 105 - In 106 - In 111 - In 133 - In	134) / In 48 x 100)				9.02%
12	ADDITIONAL REVENUE REQUIREMENT for projects w/	incentive ROE's (Note B) (Worksheet K)					-
13		REVENUE REQUIREMENT FOR SO	CHEDULE 1A CHARGES				
14 15 16	Total Load Dispatch & Scheduling (Account 561) Less: Load Dispatch - Scheduling, System Control and E Less: Load Dispatch - Reliability, Planning & Standards I						15,750,749 8,170,124 1,734,018
17	Total 561 Internally Developed Costs	(Line 14 - Line 15 - Line 16)					5,846,607

OHIO POWER COMPANY

	(1)	(2)	(3)		(4)	(5)
	RATE BASE CALCULATION	Data Sources (See "General Notes")	TO Total	Alle	ocator	Total Transmission
Line	KALL BAGE GALGGEATIGH	<u>(Goo' Goneral Notes)</u>	NOTE C	<u> </u>	<u> </u>	<u>Tranomicolori</u>
No.	GROSS PLANT IN SERVICE					
18	Production	(Worksheet A In 1.E)	9,594,903,388	NA	0.00000	-
19	Less: Production ARO (Enter Negative) Transmission	(Worksheet A In 2.E)	(147,663,530)	NA DA	0.00000	1 012 556 564
20 21	Less: Transmission ARO (Enter Negative)	(Worksheet A In 3.E & Ln 142) (Worksheet A In 4.E & Ln 143)	1,975,031,336 (3,120)	DA TP	0.96837	1,912,556,564 (3,021)
22	Plus: Transmission Plant-in-Service Additions (Wor	· ·	N/A	NA	0.00000	N/A
23	Plus: Additional Trans Plant on Transferred Assets	•	N/A	NA	0.00000	N/A
24	Distribution	(Worksheet A In 5.E)	3,629,498,388	NA	0.00000	-
25	Less: Distribution ARO (Enter Negative)	(Worksheet A In 6.E)	-	NA	0.00000	-
26	General Plant	(Worksheet A In 7.E)	237,211,272	W/S	0.06755	16,024,335
27	Less: General Plant ARO (Enter Negative)	(Worksheet A In 8.E)	(302,345)	W/S	0.06755	(20,424)
28	Intangible Plant	(Worksheet A In 9.E)	134,867,469	W/S	0.06755	9,110,703
29	TOTAL GROSS PLANT	(sum lns 18 to 28)	15,423,542,858	GP(h)= GTD=	0.12563 0.00000	1,937,668,157
30	ACCUMULATED DEPRECIATION AND AMORTIZATION	ON				
31	Production	(Worksheet A In 12.E)	3,995,173,718	NA	0.00000	-
32	Less: Production ARO (Enter Negative)	(Worksheet A In 13.E)	(62,740,187)	NA 	0.00000	
33	Transmission	(Worksheet A In 14.E & 28.E)	800,387,107	TP1=	0.96959	776,047,164
34	Less: Transmission ARO (Enter Negative)	(Worksheet A In 15.E)	(2,730)	TP1=	0.96959	(2,647)
35	Plus: Transmission Plant-in-Service Additions (Wor	•	N/A	DA	1.00000	N/A
36	Plus: Additional Projected Deprec on Transferred A	·	N/A N/A	DA TP1	1.00000	N/A
37 38	Plus: Additional Transmission Depreciation for 2013 Plus: Additional General & Intangible Depreciation f	·	N/A N/A	W/S	0.96959 0.06755	N/A N/A
39	Plus: Additional Accum Deprec on Transferred Asse		N/A	DA	1.00000	N/A
40	Distribution	(Worksheet A In 16.E)	1,377,680,530	NA	0.00000	- IVA
41	Less: Distribution ARO (Enter Negative)	(Worksheet A In 17.E)	-	NA	0.00000	-
42	General Plant	(Worksheet A In 18.E)	90,270,181	W/S	0.06755	6,098,022
43	Less: General Plant ARO (Enter Negative)	(Worksheet A In 19.E)	(180,547)	W/S	0.06755	(12,197)
44	Intangible Plant	(Worksheet A In 20.E)	120,254,303	W/S	0.06755	8,123,540
45	TOTAL ACCUMULATED DEPRECIATION	(sum Ins 31 to 44)	6,320,842,375			790,253,883
46	NET PLANT IN SERVICE					
47	Production	(ln 18 + ln 19 - ln 31 - ln 32)	5,514,806,327			-
48	Transmission	(ln 20 + ln 21 - ln 33 - ln 34)	1,174,643,838			1,136,509,025
49	Plus: Transmission Plant-in-Service Additions (In 22	•	N/A			N/A
50	Plus: Additional Trans Plant on Transferred Assets	•	N/A			N/A
51 52	Plus: Additional Transmission Depreciation for 2013 Plus: Additional General & Intangible Depreciation f		N/A N/A			N/A N/A
52 53	Plus: Additional Accum Deprec on Transferred Asse	· · · · · · · · · · · · · · · · · · ·	N/A N/A			N/A N/A
54	Distribution	(In 24 + In 25 - In 40 - In 41)	2,251,817,858			-
55	General Plant	(ln 26 + ln 27 - ln 42 - ln 43)	146,819,294			9,918,085
56	Intangible Plant	(ln 28 - ln 44)	14,613,166			987,163
57	TOTAL NET PLANT IN SERVICE	(sum Ins 47 to 56)	9,102,700,483	NP(h)=	0.12605	1,147,414,274
58	DEFERRED TAX ADJUSTMENTS TO RATE BASE	(Note D)				
59	Account No. 281.1 (enter negative)	(Worksheet B, In 2 & In 5.E)	(365,058,899)	NA		-
60	Account No. 282.1 (enter negative)	(Worksheet B, In 7 & In 10.E)	(1,721,775,224)	DA		(207,630,107)
61 62	Account No. 283.1 (enter negative)	(Worksheet B, In 12 & In 15.E)	(599,674,423)	DA		(25,438,664)
63	Account No. 190.1 Account No. 255 (enter negative)	(Worksheet B, In 17 & In 20.E) (Worksheet B, In 24 & In 25.E)	386,507,941 (435,825)	DA DA		20,998,024 (264,599)
64	TOTAL ADJUSTMENTS	(sum lns 59 to 63)	(2,300,436,429)	DA	•	(212,335,346)
		,	,	DA		,
65	PLANT HELD FOR FUTURE USE	(Worksheet A In 29.E & In 30.E)	16,588,944	DA		6,002,010
66	REGULATORY ASSETS	(Worksheet A In 36. (E))	-	DA		-
67	WORKING CAPITAL	(Note E)				
68	Cash Working Capital	(1/8 * In 88)	4,227,249		_	4,093,531
69 7 0	Transmission Materials & Supplies	(Worksheet C, In 2.F)	1,296,983	TP	0.96837	1,255,956
70 71	A&G Materials & Supplies	(Worksheet C, In 3.F)	249,065	W/S	0.06755	16,825
71 72	Stores Expense Prepayments (Account 165) - Labor Allocated	(Worksheet C, In 4.(D)) (Worksheet C, In 8.G)	435,409,304	GP(h) W/S	0.12563 0.06755	- 29,413,208
72 73	Prepayments (Account 165) - Labor Allocated Prepayments (Account 165) - Gross Plant	(Worksheet C, In 8.F)	4,728,100	GP(h)	0.12563	29,413,206 593,994
74	Prepayments (Account 165) - Transmission Only	(Worksheet C, In 8.E)	6,260	DA	1.00000	6,260
75	Prepayments (Account 165) - Unallocable	(Worksheet C, In 8.D)	(419,893,914)	NA	0.00000	-
76	TOTAL WORKING CAPITAL	(sum Ins 68 to 75)	26,023,046		•	35,379,775
77	IPP CONTRIBUTIONS FOR CONSTRUCTION	(Note F) (Worksheet D, In 8 (B))	(2,464,505)	DA	1.00000	(2,464,505)
78	RATE BASE (sum Ins 57, 64, 65, 66, 76, 77)		6,842,411,539			973,996,207
-	, - , - , - , - , - , - , - , - , - , -		, , , , , , , , , , , , , , , , , , , ,		:	,

OHIO POWER COMPANY

(1) (2) (3) (4)

Line	EXPENSE, TAXES, RETURN & REVENUE REQUIREMENTS CALCULATION	Data Sources (See "General Notes")	TO Total	Allo	ocator_	Total <u>Transmission</u>
No.	OPERATION & MAINTENANCE EXPENSE					
79	Production	321.80.b	2,425,125,006			
80	Distribution	322.156.b	155,564,708			
81	Customer Related Expense	322.164,171,178.b	239,467,579			
82	Regional Marketing Expenses	322.131.b	8,466,532			
83	Transmission	321.112.b	52,839,386			
84	TOTAL O&M EXPENSES	(sum lns 79 to 83)	2,881,463,211			
85	Less: Total Account 561	(Note G) (Worksheet F, In 14.C)	15,750,749			
86	Less: Account 565	(Note H) 321.96.b	22,667,784			
87	Less: Regulatory Deferrals & Amortizations	(Note I) (Worksheet F, In 4.C)	(19,397,139)	TD	0.00007	20.740.054
88	Total O&M Allocable to Transmission	(Ins 83 - 85 - 86 - 87)	33,817,992	TP	0.96837	32,748,251
89	Administrative and General	323.197.b (Note J)	159,175,788			
90	Less: Acct. 924, Property Insurance	323.185.b	6,727,215			
91	Acct. 9260039 PBOP Expense	PBOP Worksheet O Line 9 & 10, (Note K)	14,733,305			
92	Acct. 9260057 PBOP Medicare Subsidy	PBOP Worksheet O Line 11, (Note K)	-			
93	PBOP Expense Billed From AEPSC	PBOP Worksheet O Line 13, (Note K)	1,430,998			
94	Acct. 928, Reg. Com. Exp.	323.189.b	1,726,872			
95	Acct. 930.1, Gen. Advert. Exp.	323.191.b	14,095,546			
96	Acct. 930.2, Misc. Gen. Exp.	323.192.b	1,114,296			
97	Balance of A & G	(In 89 - sum In 90 to In 96)	119,347,556	W/S	0.06755	8,062,286
98	Plus: Acct. 924, Property Insurance	(In 90)	6,727,215	GP(h)	0.12563	845,144
99	Acct. 928 - Transmission Specific	Worksheet F In 18.(E) (Note L)	-	TP 	0.97061	-
100	Acct 930.1 - Only safety related ads -Direct	Worksheet F In 32.(E) (Note L)	-	TP	0.97061	-
101	Acct 930.2 - Misc Gen. Exp Trans	Worksheet F In 39.(E) (Note L)	188,031	DA	1.00000	188,031
102	Settlement Approved PBOP Recovery	PBOP Worksheet O, Col. C, Line 6, (Note M)	19,013,950	W/S	0.06755	1,284,450
103	A & G Subtotal	(sum lns 97 to 102)	145,276,752			10,379,911
104	O & M EXPENSE SUBTOTAL	(ln 88 + ln 103)	179,094,744		•	43,128,162
104	Plus: TEA Settlement in Account 565	Company Records (Note H)	179,094,744	DA	1.00000	45,126,162
106	Plus: Transmission Lease Payments To Affiliates in Ad	· · ·	1,351,836	DA	1.00000	1,351,836
107	TOTAL O & M EXPENSE	(ln 104 + ln 105 + ln 106)	180,446,580	D/ (1.00000	44,479,998
101		(11.101.11.100.11.11.100)	100, 110,000			11,170,000
108	DEPRECIATION AND AMORTIZATION EXPENSE					
109	Production	336.2-6.f	329,291,837	NA	0.00000	-
110	Distribution	336.8.f	94,896,667	NA	0.00000	-
111	Transmission	336.7.f	44,851,117	TP1	0.96959	43,487,185
112	Plus: Transmission Plant-in-Service Additions (Worksh	•	N/A			N/A
113	General	336.10.f	2,874,916	W/S	0.06755	194,209
114	Intangible	336.1.f	23,926,774	W/S	0.06755	1,616,326
115	TOTAL DEPRECIATION AND AMORTIZATION	(Ln 109+110+	495,841,311			45,297,720
116	TAXES OTHER THAN INCOME	111+112+113+114) (Note N)				
117	Labor Related	(NOTE IN)				
118	Payroll	Worksheet H In 22.(D)	14,141,746	W/S	0.06755	955,317
119	Plant Related		,,	, •	0.00.00	333,311
120	Property	Worksheet H In 22.(C) & In 46.(C)	214,463,890	DA		55,838,317
121	Gross Receipts/Sales & Use	Worksheet H In 22.(F)	169,923,630	NA	0.00000	-
122	Other	Worksheet H In 22.(E)	6,440,495	GP(h)	0.12563	809,123
123	TOTAL OTHER TAXES	(sum lns 118 to 122)	404,969,761			57,602,758
124	INCOME TAXES	(Note O)	05 700/			
125	T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =		35.78%			
126 127	EIT=(T/(1-T)) * (1-(WCLTD/WACC)) =		38.18%			
127	where WCLTD=(In 162) and WACC = (In 165) and FIT, SIT & p are as given in Note O.					
129	GRCF=1 / (1 - T) = (from In 125)		1.5572			
130	Amortized Investment Tax Credit (enter negative)	(FF1 p.114, ln 19.c)	(1,768,489)			
		(p ,)	(1,1 33, 133)			
131	Income Tax Calculation	(In 126 * In 134)	223,399,885			31,800,286
132	ITC adjustment	(ln 129 * ln 130)	(2,753,829)	NP(h)	0.12605	(347,126)
133	TOTAL INCOME TAXES	(sum lns 131 to 132)	220,646,056			31,453,160
134	RETURN ON RATE BASE (Rate Base*WACC)	(ln 78 * ln 165)	585,143,202			83,293,333
135	INTEREST ON IPP CONTRIBUTION FOR CONST. (Note	F) (Worksheet D, In 2.(B))	-	DA	1.00000	-
136	(Gains) / Losses on Sales of Plant Held for Future Use (W	/orksheet N, In 4, Cols. ((F) & (H))	-			-
137	Tax Impact on Net Loss / (Gain) on Sales of Plant Held for	or Future Use (In 136 * In126)	-			-
138	TOTAL REVENUE REQUIREMENT	_	1,887,046,911		•	262,126,968
100	(sum lns 107, 115, 123, 133, 134, 135)		1,007,070,011			202,120,000

OHIO POWER COMPANY

SUPPORTING CALCULATIONS

In								
No.	TRANSMISSION PLANT INCLUDED IN PJM TARIFF							
139	Total transmission plant	(In 20)						1,975,031,336
140	Less transmission plant excluded from PJM Tariff (Note	` '						-
141	Less transmission plant included in OATT Ancillary Serv	rices (Worksheet A, In 23, Col	. (C)) (Note Q)					62,474,772
142	Transmission plant included in PJM Tariff	(In 139 - In 140 - In 141)	, , ,				_	1,912,556,564
143	Percent of transmission plant in PJM Tariff	(In 142 / In 139)					TF	0.96837
144 145	WAGES & SALARY ALLOCATOR (W/S) Production	(Note R) 354.20.b	Direct Payroll 92,815,544	Payroll Billed from AEP Service Corp. 26,811,434	Total 119,626,978	NA	0.00000	_
146	Transmission	354.21.b	7,208,335	7,788,048	14,996,383	TP	0.96837	14,522,013
147	Regional Market Expenses	354.22.b	0	0	-	NA	0.00000	- 1,0==,010
148	Distribution	354.23.b	43,937,892	6,885,956	50,823,848	NA	0.00000	_
149	Other (Excludes A&G)	354.24,25,26.b	15,803,730	13,721,175	29,524,905	NA	0.00000	_
150	Total	(sum Ins 145 to 149)	159,765,501	55,206,613	214,972,114			14,522,013
151	Transmission related amount						W/S=	0.06755
152	WEIGHTED AVERAGE COST OF CAPITAL (WACC)							\$
153	Long Term Interest	(Worksheet M, In. 21, col. (E	Ξ))					217,821,003
154	Preferred Dividends	(Worksheet M, In. 56, col. (E	Ξ))					-
155	Development of Common Stock:							Average
156	Proprietary Capital	(Worksheet M, In. 1, col. (E))					4,451,435,059
157	Less: Preferred Stock	(Worksheet M, In. 2, col. (E))					-
158	Less: Account 216.1	(Worksheet M, In. 3, col. (E))					2,204,800
159	Less: Account 219	(Worksheet M, In. 4, col. (E))					(181,723,094)
160	Common Stock	(ln 156 - ln 157 - ln 158 - ln	159)					4,630,953,353
				Capital Structure	Weighting		Cost	
161		Average \$		Actual	Cap Limit		(Note S)	Weighted
162	Long Term Debt (Note T) W/S M, In 11, In 22, col. (E))	3,965,075,000	•	46.13%	49.00%		0.0549	0.0269
163	Preferred Stock (In 157)	· · · · · -		0.00%	0.00%		-	0.0000
164	Commone Stock (In 160)	4,630,953,353		53.87%	51.00%		11.49%	0.0586
165	Total (Sum Ins 162 to 164)	8,596,028,353					WACC=	0.0855
166	Capital Structure Equity Limit (Note U)	51.0%						

OHIO POWER COMPANY

<u>Notes</u>

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

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

See Worksheet E for details.

- B The annual and monthly net plant carrying charges on page 1 are used to compute the revenue requirement for RTEP sponsored upgrades or those projects receiving approved incentive-ROE's.
- C Transmission Plant balances in this study reflect the average of the balances at December 31, 2011 and December 31, 2012.
- The total-company balances shown for Accounts 281, 282, 283, 190 only reflect ADIT that relates to utility operations. The balance of Account 255 is reduced by prior flow throughs and is completely excluded if the utility chose to utilize amortization of tax credits against FIT expense. An exception to this is pre-1971 ITC balances, which are required to be taken as an offset to rate base. Account 281 is not allocated. In compliance with FERC Rulemaking RM02-7-000, Asset Retirement Obligation deferrals have been removed from ratebase. Transmission ADIT allocations are shown on WS B.

The company will not include the ADIT portion of deferred hedge gains and losses in rate base.

- E Cash Working Capital assigned to transmission is one-eighth of O&M allocated to transmission, as shown on line 88. It excludes:
 - 1) Load Scheduling & Dispatch Charges in account 561 that are collected in the OATT Ancilliary Services Revenue, as shown on line 85.
 - 2) AEP transmission equalization transfers, as shown on line 86
 - 3) The impact of state regulatory deferrals and amortizations, as shown on line 87
 - 4) All A&G Expenses, as shown on line 103.
- Consistent with Paragraph 657 of Order 2003-A, the amount on line 77 is equal to the balance of IPP System Upgrade Credits owed to transmission customers that made contributions toward the construction of System upgrades, and includes accrued interest and unreturned balance of contributions. The annual interest expense is included on line 135.
- Removes from the cost of service the Load Scheduling and Dispatch expenses booked to accounts 561.1 through 561.8. Expenses recorded in these accounts, with the exception of 561.4 & 561.8 (lines 15 & 16 above) are recovered in Schedule 1A, OATT ancillary services rates. See Worksheet F, lines 5 through 14, for descriptions and the Form 1 Source of these accounts' balances.
- Removes cost of transmission service provided by others to determine the basis of cash working capital on line 88. To the extent such service is incurred to provide the PJM service at issue, e.g. transmission equalization agreement, such costs are added back on lines 105 and 106 to determine the total O&M collected in the formula. The amounts on lines 105 and 106 are also excluded in the calculation of the FCR percentage calculated on lines 5 through 11.

 The addbacks on lines 105 and 106 of activity recorded in 565 represents inter-company sales or purchases of transmission capacity necessary to meet each AEP

The addbacks on lines 105 and 106 of activity recorded in 565 represents inter-company sales or purchases of transmission capacity necessary to meet each AEP company's transmission load relative to their available transmission capacity.

The company records referenced on lines 105 and 106 is the OHIO POWER COMPANY general ledger.

- I Removes the impact of state regulatory deferrals or their amortization from O&M expense. applicable only for state regulatory purposes.
- J General Plant and Administrative & General expenses, other than in accounts 924, 928, and 930, will be functionalized based on the Wages & Salaries "W/S" allocator. The allocation basis for accounts 924, 928 and 930 are separately presented in the formula. A change in the allocation method for an account must be approved via a 205 filing with the FERC.
- K These deductions on lines 91 through 93 are to remove from the cost of service the expenses recorded by the company for Postemployment Benefits Other than Pensions (PBOP). See Note M below for the recoverable PBOP expense.
- Expenses reported for these A&G accounts will be included in the cost of service only to the extent they are directly assignable to transmission service. Worksheet F allocates these expense items. Acct 928 Includes Regulatory Commission expenses itemized in FERC Form-1 at page 351, column H. FERC Assessment Fees and Annual Charges shall not be allocated to transmission. Only safety-related and educational advertising costs in Account 930.1 are included in the TCOS. Account 930.2 includes the expenses incurred by the transmission function for Associated Business Development revenues given as a credit to the TCOS on Worksheet E.
- M See note K above. Per the settlement in Docket ER08-1329, recoverable PBOP expense is based on an annual total for the operating companies that is ratioed to them based on the total of actual annual PBOP costs, including charges from the AEP Service Corportation. The calculation of the recoverable amount for each company is shown on Worksheet O, and the process for updating the annual total is documented on Attachment F, Allowable PBOP Expense Formula.
- N Includes only FICA, unemployment, highway, property and other assessments charged in the current year. Gross receipts, sales & use and taxes related to income are excluded.
- The currently effective income tax rate, where FIT is the Federal income tax rate; SIT is the State income tax rate, and p = the percentage of federal income tax deductible for state income taxes. See Worksheet G for the development of the Company's composite SIT. A utility that elected to utilize amortization of tax credits against taxable income, rather than book tax credits to Account No. 255 and reduce rate base, must reduce its income tax expense by the amount of the Amortized Investment Tax Credit (Form 1, 266.8.f) (In 130) multiplied by (1/1-T). If the applicable tax rates are zero enter 0.

Inputs Required:

FIT = 35.00%

SIT= 1.20% (State Income Tax Rate or Composite SIT. Worksheet G))
p = 0.00% (percent of federal income tax deductible for state purposes)

- P Removes plant excluded from the OATT because it does not meet the PJM's definition of Transmission Facilities or is otherwise ineligible to be recovered under the OATT.
- Q Removes transmission plant (e.g. step-up transformers) included in the development of OATT ancillary service rates and not already removed for reasons indicated in Note P.
- R Includes functional wages & salaries billed by AEP Service Corporation for support of the operating company.
- Long Term Debt cost rate = long-term interest (ln 153) / long term debt (ln 162). Preferred Stock cost rate = preferred dividends (ln 154) / preferred outstanding (ln 163). Common Stock cost rate (ROE) = 11.49%, the rate accepted by FERC in Docket No. ER08-1329. It includes an additional 50 basis points for PJM RTO membership. Interest expense for the true-up WACC is based on actual expenses for the true-up year. The amount of eligible hedging gains or losses included in total interest expense is limited to five basis points of the true-up capital structure. Details and calculations of the true-up weighted average cost of capital are shown on Worksheet M. Eligible Hedging Gains and Losses are defined in the Formula Protocols in the tariff, and on Worksheet M.
- T This note only applies to Indiana Michigan Power Company.
- Per Settlement, equity for OHIO POWER COMPANY is limited to 51% of Capital Structure. If the percentage of equity exceeds the cap, the excess is included in weighted percentage of long term debt in the capital structure.

 During the period ended December 31, 2011 the equity cap is in effect. During this period, a change in the cap percentage must be approved via a 205 filing with the FERC.

AEP East Companies Cost of Service Formula Rate Using 2012 FF1 Balances Worksheet A Supporting Plant Balances OHIO POWER COMPANY

(A) (B) (C) (D) (E) <u>Line</u> Balance @ December Balance @ December Average Balance Rate Base Item & Supporting Balance <u>Number</u> Source of Data <u>31, 2012</u> <u>31, 2011</u> for 2012 NOTE: Functional ARO investment and accumulated depreciation balances shown below are included in the total functional balances shown here. Plant Investment Balances 1 **Production Plant In Service** 9,554,099,448 FF1, page 205 Col.(g) & pg. 204 Col. (b), ln 46 9,635,707,327 9,594,903,388 2 156,781,322 **Production Asset Retirement Obligation (ARO)** FF1, page 205&204, Col.(g)&(b), Ins 15,24,34,44 138,545,737 147,663,530 FF1, page 207 Col.(g) & pg. 206 Col. (b), ln 58 2,007,735,450 1,942,327,221 Transmission Plant In Service 1,975,031,336 **Transmission Asset Retirement Obligation** FF1, page 207 Col.(g) & pg. 206 Col. (b), ln 57 3,120 3,120 3,120 FF1, page 207 Col.(g) & pg. 206 Col. (b), ln 75 3,718,113,471 3,540,883,305 5 **Distribution Plant In Service** 3,629,498,388 **Distribution Asset Retirement Obligation** FF1, page 207 Col.(g) & pg. 206 Col. (b), In 74 **General Plant In Service** FF1, page 207 Col.(g) & pg. 206 Col. (b), ln 99 243,597,754 230,824,790 237,211,272 **General Asset Retirement Obligation** FF1, page 207 Col.(g) & pg. 206 Col. (b), ln 98 306,041 298,648 302,345 9 Intangible Plant In Service FF1, page 205 Col.(g) & pg. 204 Col. (b), ln 5 138,963,972 130,770,966 134,867,469 15,571,511,852 15,744,117,974 15,398,905,730 10 **Total Property Investment Balance** (Sum of Lines: 3, 1, 5, 7, 9) 157,090,483 138,847,505 147,968,994 11 Total ARO Balance (included in total on line 10) (Sum of Lines: 4, 2, 6, 8) Accumulated Depreciation & Amortization Balances 12 4,248,263,554 3,742,083,882 **Production Accumulated Depreciation** FF1, page 219, Ins 20-24, Col. (b) 3,995,173,718 13 **Production ARO Accumulated Depreciation** Company Records - Note 1 83,178,723 42,301,650 62,740,187 817,203,711 14 **Transmission Accumulated Depreciation** FF1, page 219, ln 25, Col. (b) 783,570,503 800,387,107 15 **Transmission ARO Accumulated Depreciation** Company Records - Note 1 2,793 2,667 2,730 16 **Distribution Accumulated Depreciation** FF1, page 219, In 26, Col. (b) 1,391,679,118 1,363,681,942 1,377,680,530 17 **Distribution ARO Accumulated Depreciation** Company Records - Note 1 91,783,557 18 **General Accumulated Depreciation** FF1, page 219, In 28, Col. (b) 88,756,804 90,270,181 19 **General ARO Accumulated Depreciation** Company Records - Note 1 184,484 176,610 180,547 120,774,423 120,254,303 20 **Intangible Accumulated Amortization** FF1, page 200, In 21, Col. (b) 119,734,183 21 6,669,704,363 6,097,827,314 6,383,765,839 **Total Accumulated Depreciation or Amortization** (Sum of Lines: 14, 12, 16, 18, 20) 83,366,000 42,480,927 22 Total ARO Balance (included in total on line 21) (Sum of Lines: 15, 13, 17, 19) 62,923,464 **Generation Step-Up Units** 23 65,943,676 **GSU Investment Amount** Company Records - Note 1 59,005,867 62,474,772 24 **GSU Accumulated Depreciation** Company Records - Note 1 25,779,798 22,900,088 24,339,943 33,226,069 38,134,829 25 **GSU Net Balance** (Line 23 - Line 24) 43,043,588 Transmission Accumulated Depreciation Net of GSU Accumulated Depreciation **Transmission Accumulated Depreciation** (Line 14 Above) 817,203,711 783,570,503 800,387,107 26 27 22,900,088 24,339,943 **Less: GSU Accumulated Depreciation** (Line 24 Above) 25,779,798 28 **Subtotal of Transmission Net of GSU** (Line 26 - Line 27) 791,423,913 760,670,415 776,047,164 Plant Held For Future Use

FF1, page 214, ln 47, Col. (d)

Company Records - Note 1

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

16,588,944

6,002,010

16,588,944

6,002,010

16,588,944

6,002,010

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

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

Plant Held For Future Use

<u>Transmission Plant Held For Future</u>

Regulatory Assets and Liabilities Approved for Recovery In Ratebase

Total Regulatory Deferrals Included in Ratebase

29

30

AEP East Companies Cost of Service Formula Rate Using 2012 FF1 Balances Worksheet B Supporting ADIT and ITC Balances OHIO POWER COMPANY

	(A)	(A) (B) (C)		(D)	(E)	
Line			Balance @ December	Balance @ December	Average Balance	
<u>Number</u>	<u>Description</u>	<u>Source</u>	31, 2012	<u>31, 2011</u>	for 2012	
	, — .					
1	Account 281					
2	Year End Utility Deferrals	FF1, p. 272 - 273, ln 8, Col. (k)	376,657,740	353,460,058	365,058,899	
3 4	Less: ARO Related Deferrals Less: Other Excluded Deferrals	Company Records - Note 1 Company Records - Note 1	- 376,657,740	353,460,058	- 365,058,899	
5	Transmission Related Deferrals	Ln 2 - ln 3 - ln 4	-	-	-	
6	Account 282					
7	Year End Utility Deferrals	FF1, p. 274 - 275, ln 5, Col. (k)	1,764,794,823	1,678,755,624	1,721,775,224	
8	Less: ARO Related Deferrals	Company Records - Note 1	143,372,308	143,612,717	143,492,513	
9	Less: Other Excluded Deferrals	Company Records - Note 1	1,404,077,936	1,337,227,272	1,370,652,604	
10	Transmission Related Deferrals	Ln 7 - ln 8 - ln 9	217,344,579	197,915,635	207,630,107	
11	Account 283					
12	Year End Utility Deferrals	FF1, p. 276 - 277, ln 9, Col. (k)	604,077,136	595,271,709	599,674,423	
13 14	Less: ARO Related Deferrals Less: Other Excluded Deferrals	Company Records - Note 1 Company Records - Note 1	- 583,369,588	565,101,929	- 574,235,759	
15	Transmission Related Deferrals	Ln 12 - ln 13 - ln 14	20,707,549	30,169,780	25,438,664	
16	Account 190					
17	Year End Utility Deferrals	FF1, p. 234, ln 8, Col. (c)	359,572,801	413,443,081	386,507,941	
18	Less: ARO Related Deferrals	Company Records - Note 1	92,573,078	82,805,850	87,689,464	
19	Less: Other Excluded Deferrals	Company Records - Note 1	246,153,553	309,487,354	277,820,454	
20	Transmission Related Deferrals	Ln 17 - ln 18 - ln 19	20,846,170	21,149,877	20,998,024	
21	Account 255					
22 23	Year End ITC Balances Less: Balances Not Qualified for Ratebase	FF1, p. 266-267, ln 8, Col. (h) Company Records - Note 1	11,643,327 11,320,971	13,492,560 12,943,267	12,567,944 12,132,119	
	ITC Balances Includeable Ratebase	Ln 22 - In 23	322,356	549,293	435,825	
24 25	Transmission Related Deferrals	Company Records - Note 1	191,502	337,695	435,625 264,599	
			,	33.,333	== .,===	

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

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

AEP East Companies Cost of Service Formula Rate Using 2012 FF1 Balances Worksheet C Supporting Working Capital Rate Base Adjustments OHIO POWER COMPANY

ONIO POWER COMPANT										
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(1)	
			Mater	ials & Supplies						
					Polones @ December 24	Average Balance for				
<u>ne</u> nber 1			<u>Source</u>	alance @ December 31, 2012	Balance @ December 31, 2011	Average Balance for 2012				
2		Transmission Materials & Supplies	FF1, p. 227, ln 8, Col. (c) & (b)	1,602,775	991,190	1,296,983				
3		General Materials & Supplies	FF1, p. 227, ln 11, Col. (c) & (t	223,854	274,275	249,065				
4		Stores Expense (Undistributed)	FF1, p. 227, ln 16, Col. (c) & (t	0	0	-				
			Prepaymer	nt Balance Summ	ary					
5			Average of YE Balance	Excludable <u>Balances</u>	100% Transmission <u>Related</u>	Transmission Plant <u>Related</u>	Transmission Labor <u>Related</u>	Total Included in Ratebase (E)+(F)+(G)		
3		Totals as of December 31, 2012 Totals as of December 31, 2011 Average Balance	17,727,644 22,771,855 20,249,750	(433,956,947) (405,830,881) (419,893,914)	4,940 7,580 6,260	4,444,103 5,012,096 4,728,100	447,235,548 423,583,060 435,409,304	451,684,591 428,602,736 440,143,664		
Ac	cc. No.	<u>Description</u>	Prepayments Account 165 2012 YE Balance	- Balance @ 12/3 ^o Excludable Balances	1/2012 100% Transmission <u>Related</u>	Transmission Plant <u>Related</u>	Transmission Labor Related	Total Included in Ratebase (E)+(F)+(G)	<u>Explanation</u>	
				<u>Dalalices</u>	Kelateu		Neiateu			
165 2 165	50003 50004	Prepaid Insurance Prepaid Rents Prepaid Interest Prepaid Employee Benefits	2,862,276 46,896 0 0	46,896 - -		2,862,276	- -	2,862,276 - - -	Plant Related Insurance Policies Prepaid Rents Generation	
165 165 165	50009 50010 5001212	Other Prepayments Prepaid Carry Cost-Factored AR Prepaid Pension Benefits Prepaid Taxes	4,940 125,583 447,235,548 140,000	125,583 140,000	4,940		447,235,548	-	Relates to Towers AR Factoring - Retail Only Prepaid Pension Expense Prepaid Taxes	
165 165 165	50014 50016 50017	Gavin JMG ST Prepaid Exp - Aff FAS 158 Qual Contra Asset FAS 112 ASSETS Prepayments - Coal Prepaid Pension Expense - CG&E	0 (447,235,548) 0 0 4,770,193	(447,235,548) - - 4,770,193				-	FAS 158 Liability	
165 165	50020 50021	Prepaid Pension Expense - DP&L Prepaid Insurance - EIS Prepaid Lease	8,195,929 1,581,827 0	8,195,929 - -		1,581,827		1,581,827 -	Energy INS Services	
		Subtotal - Form 1, p 111.57.c	17,727,644	(433,956,947)	4,940	4,444,103	447,235,548	451,684,591	_	
			Prepayments Account 165	- Balance @ 12/31	I/ 2011					
5 <u>Ac</u>	cc. No.	<u>Description</u>	2011 <u>YE Balance</u>	Excludable <u>Balances</u>	100% Transmission <u>Related</u>	Transmission Plant <u>Related</u>	Transmission Labor <u>Related</u>	Total Included in Ratebase (E)+(F)+(G)	<u>Explanation</u>	
165		Prepaid Insurance	3,325,221	-		3,325,221		3,325,221		
165	0000	Prepaid Rents Prepaid Interest	46,896	46,896 -			-	-	Prepaid Rents Generation	
		· · · · · ·	•				-	-		
165 165	50005	Prepaid Employee Benefits	0	-	7.500			7.500	Polatos to Towers	
165 165 165	50005 50006	Prepaid Employee Benefits Other Prepayments	7,580 251,608	- - 251.608	7,580			7,580 -	Relates to Towers AR Factoring - Retail Only	
165 165 165 165 165	50005 50006 50009 50010	Prepaid Employee Benefits	7,580 251,608 423,583,060 131,549	- - 251,608 131,549	7,580	_	423,583,060	7,580 - 423,583,060 -	AR Factoring - Retail Only	
165 165 165 165 165 165	50005 50006 50009 50010 5001211	Prepaid Employee Benefits Other Prepayments Prepaid Carry Cost-Factored AR Prepaid Pension Benefits Prepaid Taxes Gavin JMG ST Prepaid Exp - Aff	251,608 423,583,060 131,549 0	131,549 -	7,580	-	423,583,060	-	AR Factoring - Retail Only Prepaid Pension Expense Prepaid Taxes	
165 165 165 165 165 165 165	50005 50006 50009 50010 5001211 50013	Prepaid Employee Benefits Other Prepayments Prepaid Carry Cost-Factored AR Prepaid Pension Benefits Prepaid Taxes Gavin JMG ST Prepaid Exp - Aff FAS 158 Qual Contra Asset	251,608 423,583,060 131,549 0 (419,542,403)	131,549	7,580	-	423,583,060	-	AR Factoring - Retail Only Prepaid Pension Expense	
165 165 165 165 165 165 165 165	50005 50006 50009 50010 5001211 50013 50014 50016	Prepaid Employee Benefits Other Prepayments Prepaid Carry Cost-Factored AR Prepaid Pension Benefits Prepaid Taxes Gavin JMG ST Prepaid Exp - Aff	251,608 423,583,060 131,549 0	131,549 -	7,580	-	423,583,060	-	AR Factoring - Retail Only Prepaid Pension Expense Prepaid Taxes	
165 165 165 165 165 165 165 165	50005 50006 50009 50010 5001211 50013 50014 50016 50017	Prepaid Employee Benefits Other Prepayments Prepaid Carry Cost-Factored AR Prepaid Pension Benefits Prepaid Taxes Gavin JMG ST Prepaid Exp - Aff FAS 158 Qual Contra Asset FAS 112 ASSETS Prepayments - Coal Prepaid Pension Expense - CG&E	251,608 423,583,060 131,549 0 (419,542,403) 0 2,328,742 6,760,255	131,549 - (419,542,403) - 2,328,742 6,760,255	7,580	-	423,583,060	-	AR Factoring - Retail Only Prepaid Pension Expense Prepaid Taxes	
165 165 165 165 165 165 165 165 165 165	50005 50006 50009 50010 5001211 50013 50014 50016 50017 50019	Prepaid Employee Benefits Other Prepayments Prepaid Carry Cost-Factored AR Prepaid Pension Benefits Prepaid Taxes Gavin JMG ST Prepaid Exp - Aff FAS 158 Qual Contra Asset FAS 112 ASSETS Prepayments - Coal Prepaid Pension Expense - CG&E Prepaid Pension Expense - DP&L	251,608 423,583,060 131,549 0 (419,542,403) 0 2,328,742 6,760,255 4,183,940	131,549 - (419,542,403) - 2,328,742	7,580	1 606 075	423,583,060	423,583,060 - - -	AR Factoring - Retail Only Prepaid Pension Expense Prepaid Taxes FAS 158 Liability	
165 165 165 165 165 165 165 165 165 165	50005 50006 50009 50010 5001211 50013 50014 50016 50017 50019 50020	Prepaid Employee Benefits Other Prepayments Prepaid Carry Cost-Factored AR Prepaid Pension Benefits Prepaid Taxes Gavin JMG ST Prepaid Exp - Aff FAS 158 Qual Contra Asset FAS 112 ASSETS Prepayments - Coal Prepaid Pension Expense - CG&E	251,608 423,583,060 131,549 0 (419,542,403) 0 2,328,742 6,760,255	131,549 - (419,542,403) - 2,328,742 6,760,255	7,580	1,686,875	423,583,060	423,583,060 - - -	AR Factoring - Retail Only Prepaid Pension Expense Prepaid Taxes	

AEP East Companies Cost of Service Formula Rate Using 2012 FF1 Balances Worksheet D Supporting IPP Credits OHIO POWER COMPANY

<u>Line</u> Number	(A) <u>Description</u>	(B) <u>2012</u>
1	Net Funds from IPP Customers 12/31/2011 (2012 FORM 1, P269, line 9.b)	(2,464,505.00)
2	Interest Accrual (Company Records - Note 1)	-
3	Revenue Credits to Generators (Company Records - Note 1)	-
4 5 6	Other Adjustments Accounting Adjustment (Company Records - Note 1)	
7	Net Funds from IPP Customers 12/31/2012 (2012 FORM 1, P269, line 12.f)	(2,464,505.00)
8	Average Balance for Year as Indicated in Column ((In 1 + In 7)/2)	(2,464,505.00)
Note 1	On this worksheet Company Records refers to OHIO POWER	

Note 1 On this worksheet Company Records refers to OHIO POWER COMPANY's general ledger.

AEP East Companies Cost of Service Formula Rate Using 2012 FF1 Balances Worksheet E Supporting Revenue Credits OHIO POWER COMPANY

<u>Line</u> Number	<u>Description</u>	<u>Total</u> <u>Company</u>	Non- Transmission	Transmission
1	Account 450, Forfeited Discounts (FF1 p.300.16.(b); Company Records - Note 1)	3,208,602	3,208,602	-
2	Account 451, Miscellaneous Service Revenues (FF1 p.300.17.(b); Company Records - Note 1)	7,681,846	7,561,989	119,857
3	Account 454, Rent from Electric Property (FF1 p.300.19.(b); Company Records - Note 1)	29,427,587	20,607,501	8,820,086
4	Account 4560015, Associated Business Development - (Company Records - Note 1)	2,460,269	2,293,334	166,935
5	Account 456 - Other Electric Revenues - (Company Records - Note 1)	98,705,326	98,438,200	267,126
6	Subtotal - Other Operating Revenues (Company Total equals (FF1 p. 300.26.(b))	141,483,630	132,109,626	9,374,004
7	Accounts 4470004 & 5, Revenues from Grandfathered Transmission Contracts - (Company Records - Note 1)	-	-	•
8	Total Other Operating Revenues To Reduce Revenue Requirement	141,483,630	132,109,626	9,374,004

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

AEP East Companies Cost of Service Formula Rate Using 2012 FF1 Balances Worksheet F Supporting Allocation of Specific O&M or A&G Expenses OHIO POWER COMPANY

Lime Number Num		(A)	(B)		(D)	(E) 100%	(F)
Total					<u> </u>	Transmission	
Total	Number	<u>Item No.</u>	<u>Description</u>	<u>Expense</u>	Non-Transmission	<u>Specific</u>	<u>Explanation</u>
Total							
Total							
Detail of Account 561 Per FERC Form 1	1	566000E		(10 207 120)			
Page	2	5000005	Onlo E-TCR Rider UnderRecovery	(19,397,139)			
Detail of Account 561 Per FERC Form 1							
FFI p 321.8.b. 561 - Load Dispatch- Reliability 34.962			Total	(19,397,139)			
FFI p 321.8.b. 561 - Load Dispatch- Reliability 34.962			Datail of Account 561 Par EEDC Form 1				
FFI p 321 85b 561.1 - Load Dispatch - Reliability 34,982	5	FF1 n 321 84 h		0			
FFI p 321.87b		•		•			
FF1 p 321.87.b 561.3 - Load Dispatch - Trans Service & Scheduling FF1 p 321.89.b 561.5 - Reliability, Pitanning and Standards Development 798.616 7798.61	7	•					
FFI p 321.88b 561.4 - Scheduling, System Control & Dispatch FFI p 321.99b 561.5 - Reliability, Planning and Standards Development 798.616 1 FFI p 321.91b 561.5 - Reliability, Planning and Standards Development 798.616 1 FFI p 321.92b 561.7 - Generation Interconnection Studies 0 561.8 - Reliability, Planning and Standards Development Servi 1.734.018 1 Total of Account 561 15.750,749	8	•	·				
FFI p 3218.0b		•	·				
FFI p 321 91.0 S61.6 - Transmission Service Studies 0 SFI p 321 92.0 S61.7 - Generation Interconnection Studies 0 S61.8 - Reliability, Planning and Standards Development Servi 1,734,018 15,750,749		•					
FF1 p 321.91.b 561.7 - Generation Interconnection Studies 0 561.8 - Reliability, Planning and Standards Development Servi 1,734.018 15,750,749		•		0			
FF1 p 321.92.b 561.8 - Reliability, Planning and Standards Development Servi 1,734,018 Total of Account 951 15,750,749		•		0			
Total of Account 561 15,750,749		•		1,734,018			
15		·					
15			Account 928				
Regulatory Commission Exp-Adm 361,418 361,418 -	15	9280000		2 272	2 272	_	
17 9280002 Regulatory Commission Exp-Case 1,363,182 1,363,182 -						_	
Total						-	
Account 930.1							
19 9301000 General Advertising Expenses 124,848 124,848 - 20 9301001 Newspaper Advertising Space 370,294 370,294 - 21 9301003 TV Station Advertising Time 6,033,025 - - 22 9301006 Spec Corporate Comm Info Project 3 3 23 9301007 Special Adv Space & Prod Exp 1,006,615 1,006,615 - 24 9301008 Direct Mail and Handouts - - - - 25 9301009 Fairs, Shows, and Exhibits 342,375 342,375 - 26 9301010 Publicity 88,061 88,061 - 27 9301011 Dedications, Tours, & Openings 9 9 9 28 9301012 Public Opinion Surveys 93,007 93,007 - 29 9301013 Movies Slide Films & Speeches - - - 30 9301014 Video Communications 112 112 31 9301015 Other Corporate Expenses 1,139,883 1,139,883	10		1 Otal	1,720,872	1,720,072	-	
20 9301001 Newspaper Advertising Space 370,294 370,294 -							
21 9301003 TV Station Advertising Time 6,033,025 6,033,025 22 9301006 Spec Corporate Comm Info Project 3 3 23 9301007 Special Adv Space & Prod Exp 1,006,615 1,006,615 - 24 9301008 Direct Mail and Handouts - - - - 25 9301009 Fairs, Shows, and Exhibits 342,375 342,375 - - 26 9301010 Publicity 88,061 88,061 - - - 27 9301011 Dedications, Tours, & Openings 9 9 - - - 28 9301012 Public Opinion Surveys 93,007 93,007 - - - 29 9301013 Movies Slide Films & Speeches - <td></td> <td></td> <td>· · · · · · · · · · · · · · · · · · ·</td> <td>•</td> <td></td> <td>-</td> <td></td>			· · · · · · · · · · · · · · · · · · ·	•		-	
22 9301006 Spec Corporate Comm Info Project 3 3 23 9301007 Special Adv Space & Prod Exp 1,006,615 1,006,615 - 24 9301008 Direct Mail and Handouts - - - - 25 9301009 Fairs, Shows, and Exhibits 342,375 342,375 - 26 9301010 Publicity 88,061 88,061 - 27 9301011 Dedications, Tours, & Openings 9 9 9 28 9301012 Public Opinion Surveys 93,007 93,007 - 29 9301013 Movies Slide Films & Speeches - - - 30 9301014 Video Communications 112 112 31 9301015 Other Corporate Comm Exp 6,037,198 6,037,198 - 32 Total 14,095,547 14,095,547 - 33 9302000 Misc General Expenses 1,139,883 1,139,883 34 9302003 Corporate & Fiscal Expenses 165,336 165,336 35 9302004 </td <td></td> <td></td> <td></td> <td></td> <td>•</td> <td>-</td> <td></td>					•	-	
23 9301007 Special Adv Space & Prod Exp 1,006,615 1,006,615 - 24 9301008 Direct Mail and Handouts - - - 25 9301009 Fairs, Shows, and Exhibits 342,375 342,375 - 26 9301010 Publicity 88,061 88,061 - 27 9301011 Dedications, Tours, & Openings 9 9 9 - 28 9301012 Public Opinion Surveys 93,007 93,007 - - 29 9301013 Movies Slide Films & Speeches - - - - - 30 9301014 Video Communications 112 112 112 112 31 9301015 Other Corporate Comm Exp 6,037,198 6,037,198 - 32 Total 14,095,547 14,095,547 - 33 9302000 Misc General Expenses 1,139,883 1,139,883 34 9302003 Corporate & Fiscal Expenses 165,336 165,336 35 9302004 Research, Develop&Demonstr Exp							
24 9301008 Direct Mail and Handouts -							
25 9301009 Fairs, Shows, and Exhibits 342,375 342,375 - 26 9301010 Publicity 88,061 88,061 - 27 9301011 Dedications, Tours, & Openings 9 9 - 28 9301012 Public Opinion Surveys 93,007 93,007 - 29 9301013 Movies Slide Films & Speeches - - - 30 9301014 Video Communications 112 112 31 9301015 Other Corporate Comm Exp 6,037,198 6,037,198 - 32 Total 14,095,547 14,095,547 - 33 9302000 Misc General Expenses 1,139,883 1,139,883 34 9302000 Misc General Expenses 165,336 165,336 35 9302004 Research, Develop&Demonstr Exp 16,094 16,094 36 9302007 Assoc Business Development Exp 1,091,815 903,784 188,031 37 9302019 gSMART-Ov/Und Misc Gen Exp (1,301,988) -1,301,988 38 9302458				1,006,615	1,006,615	-	
26 9301010 Publicity 88,061 88,061 - 27 9301011 Dedications, Tours, & Openings 9 9 - 28 9301012 Public Opinion Surveys 93,007 93,007 - 29 9301013 Movies Slide Films & Speeches - - - 30 9301014 Video Communications 112 112 31 9301015 Other Corporate Comm Exp 6,037,198 6,037,198 - 32 Total 14,095,547 14,095,547 - 33 9302000 Misc General Expenses 1,139,883 1,139,883 34 9302003 Corporate & Fiscal Expenses 165,336 165,336 35 9302004 Research, Develop&Demonstr Exp 16,094 16,094 36 9302007 Assoc Business Development Exp 1,091,815 903,784 188,031 37 9302019 gSMART-Ov/Und Misc Gen Exp (1,301,988) -1,301,988 38 9302458 AEPSC Non-affiliated Exp 3,156 3,156				- 3/2 375	- 3/12/375	-	
27 9301011 Dedications, Tours, & Openings 9 9 - 28 9301012 Public Opinion Surveys 93,007 93,007 - 29 9301013 Movies Slide Films & Speeches - - - - 30 9301014 Video Communications 112 112 - 31 9301015 Other Corporate Comm Exp 6,037,198 6,037,198 - 32 Total 14,095,547 14,095,547 - Account 930.2 33 9302000 Misc General Expenses 1,139,883 1,139,883 34 9302003 Corporate & Fiscal Expenses 165,336 165,336 35 9302004 Research, Develop&Demonstr Exp 16,094 16,094 36 9302007 Assoc Business Development Exp 1,091,815 903,784 188,031 37 9302019 gSMART-Ov/Und Misc Gen Exp (1,301,988) -1,301,988 38 9302458 AEPSC Non-affiliated Exp 3,156 3,156						-	
28 9301012 Public Opinion Surveys 93,007 93,007 - 29 9301013 Movies Slide Films & Speeches - - - - 30 9301014 Video Communications 112 112 112 31 9301015 Other Corporate Comm Exp 6,037,198 6,037,198 - 32 Total 14,095,547 14,095,547 - Account 930.2 33 9302000 Misc General Expenses 1,139,883 1,139,883 34 9302003 Corporate & Fiscal Expenses 165,336 165,336 35 9302004 Research, Develop&Demonstr Exp 16,094 16,094 36 9302007 Assoc Business Development Exp 1,091,815 903,784 188,031 37 9302019 gSMART-Ov/Und Misc Gen Exp (1,301,988) -1,301,988 38 9302458 AEPSC Non-affiliated Exp 3,156 3,156					•	_	
29 9301013 Movies Slide Films & Speeches -						-	
30 9301014 Video Communications 112 112 31 9301015 Other Corporate Comm Exp 6,037,198 6,037,198 - 32 Total 14,095,547 14,095,547 - 33 9302000 Misc General Expenses 1,139,883 1,139,883 34 9302003 Corporate & Fiscal Expenses 165,336 165,336 35 9302004 Research, Develop&Demonstr Exp 16,094 16,094 36 9302007 Assoc Business Development Exp 1,091,815 903,784 188,031 37 9302019 gSMART-Ov/Und Misc Gen Exp (1,301,988) -1,301,988 38 9302458 AEPSC Non-affiliated Exp 3,156 3,156		9301013	· · · · · · · · · · · · · · · · · · ·	· -	· -	-	
Account 930.2 14,095,547 14,095,547 - Account 930.2 Misc General Expenses 1,139,883 1,139,883 34 9302003 Corporate & Fiscal Expenses 165,336 165,336 35 9302004 Research, Develop&Demonstr Exp 16,094 16,094 36 9302007 Assoc Business Development Exp 1,091,815 903,784 188,031 37 9302019 gSMART-Ov/Und Misc Gen Exp (1,301,988) -1,301,988 38 9302458 AEPSC Non-affiliated Exp 3,156 3,156	30	9301014		112	112		
Account 930.2 33 9302000 Misc General Expenses 1,139,883 1,139,883 34 9302003 Corporate & Fiscal Expenses 165,336 165,336 35 9302004 Research, Develop&Demonstr Exp 16,094 16,094 36 9302007 Assoc Business Development Exp 1,091,815 903,784 188,031 37 9302019 gSMART-Ov/Und Misc Gen Exp (1,301,988) -1,301,988 38 9302458 AEPSC Non-affiliated Exp 3,156	31	9301015	Other Corporate Comm Exp	6,037,198	6,037,198	-	
33 9302000 Misc General Expenses 1,139,883 1,139,883 34 9302003 Corporate & Fiscal Expenses 165,336 165,336 35 9302004 Research, Develop&Demonstr Exp 16,094 16,094 36 9302007 Assoc Business Development Exp 1,091,815 903,784 188,031 37 9302019 gSMART-Ov/Und Misc Gen Exp (1,301,988) -1,301,988 38 9302458 AEPSC Non-affiliated Exp 3,156	32		Total	14,095,547	14,095,547	-	
34 9302003 Corporate & Fiscal Expenses 165,336 35 9302004 Research, Develop&Demonstr Exp 16,094 36 9302007 Assoc Business Development Exp 1,091,815 903,784 37 9302019 gSMART-Ov/Und Misc Gen Exp (1,301,988) -1,301,988 38 9302458 AEPSC Non-affiliated Exp 3,156			Account 930.2				
35 9302004 Research, Develop&Demonstr Exp 16,094 36 9302007 Assoc Business Development Exp 1,091,815 903,784 188,031 37 9302019 gSMART-Ov/Und Misc Gen Exp (1,301,988) -1,301,988 38 9302458 AEPSC Non-affiliated Exp 3,156	33	9302000	Misc General Expenses	1,139,883	1,139,883		
36 9302007 Assoc Business Development Exp 1,091,815 903,784 188,031 37 9302019 gSMART-Ov/Und Misc Gen Exp (1,301,988) -1,301,988 38 9302458 AEPSC Non-affiliated Exp 3,156					·		
37 9302019 gSMART-Ov/Und Misc Gen Exp (1,301,988) -1,301,988 38 9302458 AEPSC Non-affiliated Exp 3,156 3,156				•			
38 9302458 AEPSC Non-affiliated Exp 3,156 3,156			·		· ·	188,031	
			· ·				
39 Total 1,114,296 926,265 188,031	38	9302458	AEPSC Non-affiliated Exp	3,156	3,156		
	39		Total	1,114,296	926,265	188,031	

AEP East Companies

Cost of Service Formula Rate Using 2012 FF1 Balances Worksheet G Supporting - Development of Composite State Income Tax Rate OHIO POWER COMPANY

West Virginia Corporate Income Tax Apportionment Factor - Note 2 Effective State Tax Rate	7.75% 8.66%	0.67%
Illinois Corporation Income Tax Apportionment Factor - Note 2 Effective State Tax Rate	9.50% 1.94%	0.18%
Michigan Business Income Tax Apportionment Factor - Note 2 Effective State Tax Rate	6.00% 0.09%	0.01%
Kentucky Business Income Tax Apportionment Factor - Note 2 Effective State Tax Rate	6.00% 0.93%	0.06%
Ohio Municipal Net Income Tax Apportionment Factor - Note 2 Effective State Tax Rate	0.36% 79.18%	0.29%
Ohio Franchise Tax Rate Phase-out Factor Note 1 Apportionment Factor - Note 2 Effective State Tax Rate	0.00% 0.00% 0.00%	0.009/
Total Effective State Income Tax Rate		0.00%

Note 2 Apportionment Factors are determined as part of the Company's annual tax return for that jurisdiction.

The Ohio State Income Tax is being phased-out prorata over a 5 year period from 2005 through 2009. The taxable portion of income is 0% 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 Activites Tax that is included in Schedule H and H-1.

AEP East Companies Cost of Service Formula Rate Using 2012 FF1 Balances Worksheet H Supporting Taxes Other than Income OHIO POWER COMPANY

	(A)	(B)	(C)	(D)	(E)	(F)
Line No.	Account	Total Company NOTE 1	Property	Labor	Other	Non-Allocable
	_					
1 2	Revenue Taxes Gross Receipts Tax	153,709,013				153,709,013
3 4	Real Estate and Personal Property Taxes Real and Personal Property - Ohio	200,874,277	200,874,277			
5	Real and Personal Property - West VA.	13,552,910	13,552,910			
6	Real and Personal Property - Other	36,703	36,703			
7	Payroll Taxes					
8	Federal Insurance Contribution (FICA)	12,667,108		12,667,108		
9	Federal Unemployment Tax	163,225		163,225		
10	State Unemployment Insurance	109,155		109,155		
11	Payroll Taxes	1,202,258		1,202,258		
12	Production Taxes					
13	State Severance Taxes	-				-
14	Miscellaneous Taxes					
15	State Public Service Commission Fees	5,879,061			5,879,061	
16	State Franchise Taxes	556,047			556,047	
17	State Lic/Registration Fee	5,387			5,387	
18	Misc. State and Local Tax	- (4.000)			-	(4.000)
19	Sales & Use	(1,089)				(1,089)
20 21	Federal Excise Tax State B & O Taxes	8,233 16,207,473				8,233 16,207,473
22	Total Taxes by Allocable Basis	404,969,761	214,463,890	14,141,746	6,440,495	169,923,630
	(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 sho Functional Property Tax Production		Distribution	General	Total
23	Functionalized Net Plant (Hist. TCOS, Lns 212 thru 222) OHIO JURISDICTION	5,313,841,174	1,190,531,412	2,326,434,353	151,692,640	8,982,499,579
24	Percentage of Plant in OHIO JURISDICTION	62.26%	92.89%	99.96%	98.41%	
25	Net Plant in OHIO JURISDICTION (Ln 23 * Ln 24)	3,308,362,372	1,105,844,706	2,325,505,315	149,273,715	6,888,986,107
26	Less: Net Value Exempted Generation Plant	1,380,205,938				
27	Taxable Property Basis (Ln 25 - Ln 26)	1,928,156,434	1,105,844,706	2,325,505,315	149,273,715	5,508,780,169
28	Relative Valuation Factor	<u>24%</u>	85%	1 076 670 517	25 925 602	
29 30	Weighted Net Plant (Ln 27 * Ln 28) General Plant Allocator (Ln 29 / (Total - General Plant))	462,757,544 13.69%	939,968,000 27.81%	1,976,679,517 58.49%	35,825,692 -100.00%	
31	Functionalized General Plant (Ln 30 * General Plant)	4,905,777	9,964,773	20,955,141	(35,825,692)	_
30a	Ohio Company Merger Mitigation adjustment (Note 2)	31,000,000	(31,000,000)	20,000,111	(00,020,002)	_
32	Weighted OHIO JURISDICTION Plant (Ln 29 + 31 + 30a)	498,663,321	918,932,773	1,997,634,658	(0)	3,415,230,753
33	Functional Percentage (Ln 32/Total Ln 32)	14.60%	26.91%	58.49%	, ,	
34	Functionalized Payment in OHIO JURISDICTION	29,329,975	54,049,044	117,495,258		200,874,277
	WEST VA JURISDICTION					
35	Net Plant in WEST VA JURISDICTION (Ln - Ln 24)	2,005,478,802	84,686,706	929,038	2,418,925	2,093,513,472
36	Less: Net Value Exempted Generation Plant	1,447,919,082				
37	Taxable Property Basis	557,559,720	84,686,706	929,038	2,418,925	645,594,390
38	Relative Valuation Factor	100%	100%	100%	100%	
39 40	Weighted Net Plant (Ln 37 * Ln 38)	557,559,720	84,686,706	929,038	2,418,925	
40 41	General Plant Allocator (Ln 39 / (Total - General Plant)	86.69% 2,096,932	13.17% 318,499	0.14% 3,494	-100.00%	
41 42	Functionalized General Plant (Ln 41 * General Plant) Weighted WEST VA JURISDICTION Plant (Ln 39 + 41)	2,096,932 559,656,652	318,499 85,005,205	3,494 932,532	(2,418,925) 0	645,594,390
42	Functional Percentage (Ln 42/Total Ln 42)	86.69%	13.17%	0.14%	U	U T U,UU T ,UUU
44	Functionalized Payment in WEST VA JURISDICTION	11,748,826	1,784,507	19,577		13,552,910
45	Total Other Jurisdictions: (Line 7 * Net Plant Allocator)		4,766			36,703
40						-
46	Total Functionalized Property Taxes (Sum Lns 33, 44, 45)	41,078,802	55,838,317	117,514,834		214,463,890

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 2012 FF1 Balances Worksheet H-1 Form 1 Source Reference of Company Amounts on WS H OHIO POWER COMPANY

(A) (D) (B) (C) Total **FERC FORM 1** Line No. Tie-Back Annual Tax Expenses by Type (Note 1) FERC FORM 1 Reference Company Revenue Taxes Gross Receipts Tax 153,709,013 202,880 P.263 In 9 (i) 10,396,850 P.263 In 10 (i) P.263 In 13 (i) 143,109,283 Real Estate and Personal Property Taxes Real and Personal Property - Ohio 200,874,277 (7,090)P.263.1 In 4 (i) 381,603 P.263.1 In 5 (i) 200,347,858 P.263.1 In 6 (i) P.263.1 In 9 (i) (4,086)210,434 P.263.1 In 10 (i) (24,933)P.263.1 In 12 (i) (217,152)P.263.1 In 13 (i) P.263.1 In 14 (i) (83,057)270,700 P.263.1 In 15 (i) Real and Personal Property - West VA. 13,552,910 7,239,356 P.263.1 In 17 (i) 6,305,005 P.263.1 In 18 (i) P.263.1 In 22 (i) 4,552 3,997 P.263.1 In 23 (i) Real and Personal Property - Other 36,703 2,385 P.263.1 In 30 (i) (1,682) P.263.1 In 37 (i) P.263.1 In 38 (i) 36,000 Payroll Taxes 12,667,108 Federal Insurance Contribution (FICA) 12,667,108 P.263 In 3 (i) Federal Unemployment Tax 163,225 163,225 P.263 In 4 (i) 109,155 State Unemployment Insurance P.263 In 16 (i) 57,984 P.263 In 35 (i) 51,171 1,202,258 Payroll Taxes 11 P.263.2 In 14 (i) 1,202,258 **Production Taxes** State Severance Taxes 13 -Miscellaneous Taxes State Public Service Commission Fees 5,879,061 P.263 In 11 (i) 5,879,061 State Franchise Taxes 556,047 16 610,117 P.263 In 32 (i) (61,721) P.263 In 33 (i) 7,676 P.263 In 34 (i) (25) P.263.2 In 21 (i) State Lic/Registration Fee 5,387 17 625 P.263.2 In 5 (i) 4,762 P.263.2 In 6 (i) Misc. State and Local Tax (1,089)19 Sales & Use (1,790)P.263 In 14 (i) (69) P.263 In 15 (i) P.263 In 37 (i) 770 8,233 Federal Excise Tax P.263 In 6 (i) 8,233 State B & O Taxes 16,207,473 144,162 P.263 In 38 (i) P.263 In 39 (i) 15,735,811 P.263 In 40(i) 327,500 404,969,761 Total Taxes by Allocable Basis 404,969,761 (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 2012 FF1 Balances Worksheet I Supporting Transmission Plant in Service Additions OHIO POWER COMPANY

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(1)

I. Calculation of Composite Depreciation Rate

1	Transmission Plant @ Beginning of Historic Period (2012) (P.206, In 58,(b)):	1,942,327,221
2	Transmission Plant @ End of Historic Period (2012) (P.207, In 58,(g)):	2,007,735,450
3		3,950,062,671
4	Average Balance of Transmission Investment	1,975,031,336
5	Annual Depreciation Expense, Historic TCOS, In 276	44,851,117
6	Composite Depreciation Rate	2.27%
7	Round to 2.27% to Reflect a Composite Life of 44 Years	2.27%

II. Calculation of Property Placed in Service by Month and the Related Depreciation Expense

	Month in			Composite Annual Depreciation	Annual			No. Months	First Year Depreciation
8	Service	Сарі	talized Balance	Rate	Depreciation	M	onthly Depreciation	Depreciation	Expense
9	January	\$	54,876,199	2.27%	\$ 1,245,690	\$	103,807	11	\$ 1,141,877
10	February	\$	3,599,447	2.27%	\$ 81,707	\$	6,809	10	\$ 68,090
11	March	\$	4,309,900	2.27%	\$ 97,835	\$	8,153	9	\$ 73,377
12	April	\$	4,843,762	2.27%	\$ 109,953	\$	9,163	8	\$ 73,304
13	May	\$	6,588,560	2.27%	\$ 149,560	\$	12,463	7	\$ 87,241
14	June	\$	14,784,270	2.27%	\$ 335,603	\$	27,967	6	\$ 167,802
15	July	\$	5,112,238	2.27%	\$ 116,048	\$	9,671	5	\$ 48,355
16	August	\$	4,611,814	2.27%	\$ 104,688	\$	8,724	4	\$ 34,896
17	September	\$	3,724,990	2.27%	\$ 84,557	\$	7,046	3	\$ 21,138
18	October	\$	5,819,524	2.27%	\$ 132,103	\$	11,009	2	\$ 22,018
19	November	\$	3,469,582	2.27%	\$ 78,760	\$	6,563	1	\$ 6,563
20	December	\$	18,861,752	2.27%	\$ 428,162	\$	35,680	0	\$ -
21	Investment	\$	130,602,038					Depreciation Expense	\$ 1,744,661

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)	Φ.	_	— This input area is for additional Depreciation Expense

IV. List of Major Projects Expected to be In-Service in 2013

		Estimated Cost	
		(000's)	Month in Service
25 <u>Major Zonal Projects</u>			
26 Transmission Station Repl		\$5,672	Dec-13
27 Coneville - Bixby 345kV		\$8,248	Dec-13
28			
29			
30			
31	Subtotal	\$13,920	
32 PJM Socialized/Beneficiary Allocated Regional Projects			
33		\$0	
34	Subtotal	\$0	

AEP East Companies Cost of Service Formula Rate Using 2012 FF1 Balances Worksheet J Supporting Calculation of PROJECTED PJM RTEP Project Revenue Requirement Billed to Benefiting Zones OHIO POWER COMPANY

SUMMARY OF PROJECTED ANNUAL RTEP REVENUE REQUIREMENTS

3,768,661

PROJECTED YEAR

Incentive Amounts

3,768,661 \$

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, In 164)

Project ROE Incentive Adder

ROE with additional basis point incentive

11.49%

-==ROE Adder Cannot Exceed 125 Basis Points

11.49%
-== 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, Ins 162 through164)

	<u>%</u>	<u>Cost</u>	Weighted cost
Long Term Debt	45.39%	5.61%	2.544%
Preferred Stock	0.00%	0.00%	0.000%
Common Stock	54.61%	11.49%	<u>6.274%</u>
		R =	8.819%

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

Rate Base (Projected TCOS, In 78)	1,075,078,307
R (from A. above)	8.819%
Return (Rate Base x R)	94,806,722

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

Return (from B. above)	94,806,722
Effective Tax Rate (Projected TCOS, In 126)	39.64%
Income Tax Calculation (Return x CIT)	37,582,290
ITC Adjustment	(357,606)
Income Taxes	37,224,684

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, In 1)	281,223,353
T.E.A. & Lease Payments (Projected TCOS, Lns 105 & 106)	1,351,836
Return (Projected TCOS, In 134)	94,806,722
Income Taxes (Projected TCOS, In 133)	37,224,684
Annual Revenue Requirement, Less TEA Charges, Return and Taxes	147,840,111

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

Annual Revenue Requirement, Less TEA Charges, Return and Taxes	147,840,111
Return (from I.B. above)	94,806,722
Income Taxes (from I.C. above)	37,224,684
Annual Revenue Requirement, with Basis Point ROE increase	279,871,517
Depreciation (Projected TCOS, In 111)	43,436,228
Annual Rev. Req, w/ Basis Point ROE increase, less Depreciation	236,435,289

C. Determine FCR with hypothetical basis point ROE increase.

Net Transmission Plant (Projected TCOS, In 48) Annual Revenue Requirement, with Basis Point ROE increase FCR with Basis Point increase in ROE	1,157,305,347 279,871,517 24.18%
Annual Rev. Req, w / Basis Point ROE increase, less Dep. FCR with Basis Point ROE increase, less Depreciation FCR less Depreciation (Projected TCOS, In 9) Incremental FCR with Basis Point ROE increase, less Depreciation	236,435,289 20.43% <u>18.89%</u> 1.54%

III. Calculation of Composite Depreciation Rate

Transmission Plant @ Beginning of Historic Period (2012) (P.206, In 58,(b)):	1,942,327,221
Transmission Plant @ End of Historic Period (2012) (P.207, In 58,(g)):	2,007,735,450
Subtotal	3,950,062,671
Average Transmission Plant Balance for 2012	1,975,031,336
Annual Depreciation Rate (Projected TCOS, In 111)	44,851,117
Composite Depreciation Rate	2.27%
Depreciable Life for Composite Depreciation Rate	44.04
Round to nearest whole year	44

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: RTEP ID: b504 (765 kV circuit breaker installations at Hanging Rock)

Current Projected Year ARR 1,051,933
Current Projected Year ARR w/ Incentive 1,051,933
Current Projected Year Incentive ARR -

DetailsInvestment5,491,719Current Year2013Service Year (yyyy)2009ROE increase accepted by FERC (Basis Points)-Service Month (1-12)4FCR w/o incentives, less depreciation18.89%Useful life44FCR w/incentives approved for these facilities, less dep.18.89%CIAC (Yes or No)NoAnnual Depreciation Expense124,812

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.

611 to (168 61 116)		7 tillidal Depresiation E				124,012			
							RTEP Projected Rev. Req't.From	RTEP Projected Rev. Req't.From	
Investment Year	Beginning Balance	Depreciation Expense	Ending Balance	RTEP Rev. Req't. w/o Incentives	RTEP Rev. Req't. with Incentives **	Incentive Rev. Requirement ##	Prior Year Template w/o Incentives	Prior Year Template with Incentives **	
2009	5,491,719	83,208	5,408,511	1,104,613	1,104,613	\$ -	\$ 894,796	\$ 894,796	
2010	5,408,511	124,812	5,283,699	1,122,646	1,122,646		\$ 1,094,271	\$ 1,094,271	
2011	5,283,699	124,812	5,158,888	1,099,075	1,099,075		\$ 1,210,680	\$ 1,210,680	
2012	5,158,888	124,812	5,034,076	1,075,504	1,075,504		\$ 1,057,666	\$ 1,057,666	
2013	5,034,076	124,812	4,909,264	1,051,933	1,051,933				
2014	4,909,264	124,812	4,784,452	1,028,362	1,028,362	\$ -			
2015	4,784,452	124,812	4,659,640	1,004,791	1,004,791	\$ -			
2016	4,659,640	124,812	4,534,829	981,220	981,220				
2017	4,534,829	124,812	4,410,017	957,650	957,650				
2018	4,410,017	124,812	4,285,205	934,079	934,079				
				-					
2019	4,285,205	124,812	4,160,393	910,508	910,508				
2020	4,160,393	124,812	4,035,581	886,937	886,937				
2021	4,035,581	124,812	3,910,770	863,366	863,366	\$ -			
2022	3,910,770	124,812	3,785,958	839,795	839,795	\$ -			
2023	3,785,958	124,812	3,661,146	816,224	816,224				
2024	3,661,146	124,812	3,536,334	792,653	792,653				
2025	3,536,334	124,812	3,411,522	769,083	769,083				
2026	3,411,522	124,812	3,286,711	745,512	745,512				
2027	3,286,711	124,812	3,161,899	721,941	721,941				
2028	3,161,899	124,812	3,037,087	698,370	698,370	\$ -			
2029	3,037,087	124,812	2,912,275	674,799	674,799	\$ -			
2030	2,912,275	124,812	2,787,463	651,228	651,228				
2031	2,787,463	124,812	2,662,652	627,657	627,657				
2032	2,662,652	124,812	2,537,840	604,086	604,086				
2033	2,537,840	124,812	2,413,028	580,515	580,515				
2034	2,413,028	124,812	2,288,216	556,945	556,945				
2035	2,288,216	124,812	2,163,404	533,374	533,374	\$ -			
2036	2,163,404	124,812	2,038,593	509,803	509,803	\$ -			
2037	2,038,593	124,812	1,913,781	486,232	486,232	\$ -			
2038	1,913,781	124,812	1,788,969	462,661	462,661	*			
2039	1,788,969	124,812	1,664,157	439,090	439,090				
2040	1,664,157	124,812	1,539,345	415,519	415,519				
2041	1,539,345	124,812	1,414,534	391,948	391,948				
2042	1,414,534	124,812	1,289,722	368,378	368,378	\$ -			
2043	1,289,722	124,812	1,164,910	344,807	344,807				
2044	1,164,910	124,812	1,040,098	321,236	321,236				
2045	1,040,098	124,812	915,286	297,665	297,665				
2046	915,286	124,812	790,475	274,094	274,094				
2047	790,475	124,812	665,663	250,523	250,523	\$ -			
2048	665,663	124,812	540,851	226,952	226,952	\$ -			
2049	540,851	124,812	416,039	203,381	203,381	\$ -			
2050	416,039	124,812	291,228	179,811	179,811	\$ -			
2051	291,228	124,812	166,416	156,240	156,240				
2052	166,416	124,812	41,604	132,669	132,669				
			41,004						
2053	41,604	41,604	-	41,604	41,604	Φ.			
2054	-	-	-	-	-	\$ -			
2055	-	-	-	-	-	\$ -			
2056	-	-	-	-	-	\$ -			
2057	-	-	-	-	-	\$ -			
2058	_	_	_	_	_	\$ -			
2059	_	_	_	_	_	\$ -			
	_	_		_	_	Φ			
2060	-	-		-	·	-			
2061	-	-	-	-	-	\$ -			
2062	-	-	-	-	-	\$ -			
2063	-	-	-	-	-	\$ -			
2064	-	-	-	-	-	\$ -			
2065	_	_	_	_	_	\$ -			
2066	_	_	_	_	_	\$ -			
	_	-				· ·			
2067	-	-		-	·	5 -			
2068	-	-	-	-	-	-			

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

Project Totals

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

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

28,135,479

28,135,479

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

A. Base Plan Facilities

69/12 kV transformer)

Facilities receiving incentives accepted by FERC in Docket No.

(e.g. ER05-925-000)

Current Projected Year ARR

Current Projected Year ARR w/ Incentive

Current Projected Year ARR w/ Incentive

RTEP ID: B1231 (Replace the existing 138/69-12 kV transformer at West Moulton Station with a 138/69 kV transformer and a

Details			
Investment	6,018,585	Current Year	2013
Service Year (yyyy)	2013	ROE increase accepted by FERC (Basis Points)	-
Service Month (1-12)	4	FCR w/o incentives, less depreciation	18.89%
Useful life	44	FCR w/incentives approved for these facilities, less dep.	18.89%
CIAC (Yes or No)	No	Annual Depreciation Expense	136,786

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.

		,	•			100,100			
							RTEP Projected	RTEP Projected	
							Rev. Req't.From	Rev. Reg't.From	
Investment	Beginning	Depreciation	Ending	RTEP Rev. Req't.	RTEP Rev. Req't.	Incentive Rev.	Prior Year Template	Prior Year Template	
Year	Balance	Expense	Balance	w/o Incentives	with Incentives **	Requirement ##	w/o Incentives	with Incentives **	
2013	6,018,585	91,191	5,927,394	1,210,587	1,210,587		\$ 832,082	\$ 832,082	
2014	5,927,394	136,786	5,790,608	1,230,350	1,230,350				
2015	5,790,608	136,786	5,653,822	1,204,518	1,204,518				
2016	5,653,822	136,786	5,517,036	1,178,686	1,178,686				
2017	5,517,036	136,786	5,380,250	1,152,854	1,152,854				
2018	5,380,250	136,786	5,243,464	1,127,022	1,127,022				
2019	5,243,464	136,786	5,106,678	1,101,189	1,101,189				
2020 2021	5,106,678 4,969,892	136,786 136,786	4,969,892 4,833,106	1,075,357 1,049,525	1,075,357 1,049,525				
2022	4,833,106	136,786	4,696,320	1,023,693	1,023,693				
2023	4,696,320	136,786	4,559,534	997,860	997,860				
2024	4,559,534	136,786	4,422,748	972,028	972,028				
2025	4,422,748	136,786	4,285,962	946,196	946,196				
2026	4,285,962	136,786	4,149,176	920,364	920,364				
2027	4,149,176	136,786	4,012,390	894,531	894,531				
2028	4,012,390	136,786	3,875,604	868,699	868,699	\$ -			
2029	3,875,604	136,786	3,738,818	842,867	842,867				
2030	3,738,818	136,786	3,602,032	817,035	817,035				
2031	3,602,032	136,786	3,465,246	791,203	791,203				
2032	3,465,246	136,786	3,328,460	765,370	765,370				
2033	3,328,460	136,786	3,191,674	739,538	739,538				
2034 2035	3,191,674	136,786	3,054,888	713,706	713,706				
2036	3,054,888 2,918,102	136,786 136,786	2,918,102 2,781,316	687,874 662,041	687,874 662,041				
2037	2,781,316	136,786	2,644,530	636,209	636,209				
2038	2,644,530	136,786	2,507,744	610,377	610,377				
2039	2,507,744	136,786	2,370,958	584,545	584,545				
2040	2,370,958	136,786	2,234,172	558,712	558,712				
2041	2,234,172	136,786	2,097,386	532,880	532,880				
2042	2,097,386	136,786	1,960,600	507,048	507,048				
2043	1,960,600	136,786	1,823,814	481,216	481,216				
2044	1,823,814	136,786	1,687,028	455,384	455,384				
2045	1,687,028	136,786	1,550,242	429,551	429,551				
2046	1,550,242	136,786	1,413,456	403,719	403,719				
2047	1,413,456	136,786	1,276,670	377,887	377,887				
2048 2049	1,276,670 1,139,884	136,786 136,786	1,139,884	352,055 326,222	352,055 326,222				
2049	1,003,098	136,786	1,003,098 866,311	300,390	300,390				
2051	866,311	136,786	729,525	274,558	274,558				
2052	729,525	136,786	592,739	248,726	248,726				
2053	592,739	136,786	455,953	222,893	222,893				
2054	455,953	136,786	319,167	197,061	197,061				
2055	319,167	136,786	182,381	171,229	171,229	\$ -			
2056	182,381	136,786	45,595	145,397	145,397	\$ -			
2057	45,595	45,595	-	45,595	45,595	-			
2058	-	-	-	-	-	-			
2059	-	-	-	-	-	\$ -			
2060	-	-	-	-	-				
2061 2062	-	-	-	-	-	φ - ¢			
2062	_	_ [- \$ -			
2064	_	_	_		_	\$ -			
2065	_	_	_	-	_	\$ -			
2066	-	-	-	-	_	\$ -			
2067	-	-	-	-	-	\$ -			
2068	-	-	-	-	-	\$ -			
2069	-	-	-	-	-	\$ -			
2070	-	-	-	-	-	\$ -			
2071	-	-	-	-	-	-			
2072	-	-	-	-	-	\$ -			
Project Totals				30,834,748	30,834,748	-			

** 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.

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. 219,263 (e.g. ER05-925-000) Current Projected Year ARR Current Projected Year ARR w/ Incentive 219,263 Project Description: RTEP ID: b0570 (Reconductor EAST LIMA-STERLING 138 KV LINE) Current Projected Year Incentive ARR

CUMULATIVE HISTORY OF PROJECTED ANNUAL REVENUE REQUIREMENTS:

RTEP Projected

Prior Year Template

Rev. Req't.From

INPUT PROJECTED ARR (WITH & WITHOUT INCENTIVES) FROM EACH PRIOR YEAR

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

CUMULATIVE HISTORY OF PROJECTED ANNUAL REVENUE REQUIREMENTS:

RTEP Projected Rev. Req't.From

Prior Year Template

Details									
Investment	1,107,003	Current Year	ent Year						
Service Year (yyyy)	2013	ROE increase accepte	OE increase accepted by FERC (Basis Points)						
Service Month (1-12)	6	FCR w/o incentives, le	R w/o incentives, less depreciation						
Useful life	44	FCR w/incentives app	R w/incentives approved for these facilities, less dep.						
CIAC (Yes or No)	No	Annual Depreciation E	ual Depreciation Expense						

AC (Yes or No)	No	Annual Depreciation E	25,159			
Investment Year	Beginning Balance	Depreciation Expense	Ending Balance	RTEP Rev. Req't. w/o Incentives	RTEP Rev. Req't. with Incentives **	Incentive Rev. Requirement ##
2013	1,107,003	12,580	1,094,423	219,263	219,263	\$ -
2014	1,094,423	25,159	1,069,264	227,091	227,091	\$ -
2015	1,069,264	25,159	1,044,105	222,340	222,340	\$ -
2016	1,044,105	25,159	1,018,946	217,589	217,589	\$ -
2017	1,018,946	25,159	993,787	212,837	212,837	\$ -
2018	993,787	25,159	968,628	208,086	208,086	\$ -
2019	968,628	25,159	943,468	203,334	203,334	\$ -
2020	943,468	25,159	918,309	198,583	198,583	\$ -
2021	918,309	25,159	893,150	193,832	193,832	\$ -
2022	893 150	25 150	867 991	189 080	189 080	\$ -

Year	Balance	Expense	Balance	w/o Incentives	with Incentives **	Requirement ##	w/o Incentives	with Incentives **	
2013	1,107,003	12,580	1,094,423	219,263	219,263	\$ -	\$ 374,752	\$ 374,752	
2014	1,094,423	25,159	1,069,264	227,091	227,091	\$ -			
2015	1,069,264	25,159	1,044,105	222,340	222,340	\$ -			
2016	1,044,105	25,159	1,018,946	217,589	217,589	\$ -			
2017	1,018,946	25,159	993,787	212,837	212,837				
2018	993,787	25,159	968,628	208,086	208,086	\$ -			
2019	968,628	25,159	943,468	203,334	203,334				
2020	943,468	25,159		198,583	198,583	\$ -			
2021	918,309	25,159	893,150	193,832	193,832	\$ -			
2022	893,150	25,159	867,991	189,080	189,080				
2023	867,991	25,159	842,832	184,329	184,329	\$ -			
2024	842,832	25,159	817,673	179,578	179,578	\$ -			
2025	817,673	25,159	792,514	174,826	174,826				
2026	792,514	25,159	767,354	170,075	170,075	\$ -			
2027	767,354	25,159	742,195	165,324	165,324	\$ -			
2028	742,195	25,159	717,036	160,572	160,572				
2029	717,036	25,159	691,877	155,821	155,821				
2030	691,877	25,159	666,718	151,070	151,070	\$ -			
2031	666,718	25,159	641,559	146,318	146,318	\$ -			
2032	641,559	25,159		141,567	141,567	\$ -			
2033	616,399	25,159	591,240	136,816	136,816	\$ -			
2034	591,240	25,159	566,081	132,064	132,064				
2035	566,081	25,159	540,922	127,313	127,313				
2036	540,922	25,159	515,763	122,562	122,562				
2037	515,763	25,159	490,604	117,810	117,810				
2038	490,604	25,159		113,059	113,059				
2039	465,444	25,159		108,308	108,308	\$ -			
2040	440,285	25,159		103,556	103,556	\$ -			
2041	415,126	25,159	389,967	98,805	98,805	\$ -			
2042	389,967	25,159	364,808	94,054	94,054	\$ -			
2043	364,808	25,159	339,649	89,302	89,302	\$ -			
2044	339,649	25,159	314,489	84,551	84,551				
2045	314,489	25,159	289,330	79,800	79,800				
2046	289,330	25,159	264,171	75,048	75,048	\$ -			
2047	264,171	25,159	239,012	70,297	70,297	\$ -			
2048	239,012	25,159	213,853	65,546	65,546	\$ -			
2049	213,853	25,159	188,694	60,794	60,794	\$ -			
2050	188,694	25,159	163,535	56,043	56,043	\$ -			
2051	163,535	25,159	138,375	51,292	51,292	\$ -			
2052	138,375	25,159	113,216	46,540	46,540	\$ -			
2053	113,216	25,159	88,057	41,789	41,789	\$ -			
2054	88,057	25,159	62,898	37,038	37,038				
2055	62,898	25,159	37,739	32,286	32,286				
2056	37,739	25,159	12,580	27,535	27,535	\$ -			
2057	12,580	12,580	-	12,580	12,580	\$ -			
2058	-	-	-	-	-	\$ -			
2059	-	-	-	-	-	\$ -			
2060	-	-	-	-	-	\$ -			
2061	-	-	-	-	-	\$ -			
2062	-	-	-	-	-	\$ -			
2063	-	-	-	-	-	\$ -			
2064	-	-	-	-	-	\$ -			
2065	-	-	-	-	-	\$ -			
2066	-	-	-	-	-	\$ -			
2067	-	-	-	-	-	\$ -			
2068	-	-	-	-	-	\$ -			
2069	-	-	-	-	-	\$ -			
2070	-	-	-	-	-	\$ -			
2071	-	-	-	-	-	\$ -			
2072	-	-	-	-	-	\$ -			

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

Project Totals

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

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

5,706,302

5,706,302

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

A. Base Plan Facilities

Facilities receiving incentives accepted by FERC in Docket No.

(e.g. ER05-925-000)

Current Projected Year ARR

Current Projected Year ARR w/ Incentive

Project Description: RTEP ID: b1034.1 (South Canton - West Canton 138kV line (replacing Torrey - West Canton) and Wagenhals – Wayview

DetailsInvestment2,800,000Current Year2013Service Year (yyyy)2013ROE increase accepted by FERC (Basis Points)-Service Month (1-12)12FCR w/o incentives, less depreciation18.89%Useful life44FCR w/incentives approved for these facilities, less dep.18.89%CIAC (Yes or No)NoAnnual Depreciation Expense63,636

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.

Current Projected Year Incentive ARR

528,784

528,784

CIAC (Yes or No)	No	Annual Depreciation E	xpense			63,636	LIFE OF THE PROJECT.		
Investment Year	Beginning Balance	Depreciation Expense	Ending Balance	RTEP Rev. Req't. w/o Incentives	RTEP Rev. Req't. with Incentives **	Incentive Rev. Requirement ##	RTEP Projected Rev. Req't.From Prior Year Template w/o Incentives	RTEP Projected Rev. Req't.From Prior Year Template with Incentives **	
2013	2,800,000	-	2,800,000	528,784	528,784	\$ -			
2014	2,800,000	25,159	2,774,841	549,192	549,192	\$ -			
2015	2,774,841	25,159	2,749,682	544,440	544,440	\$ -			
2016	2,749,682	25,159	2,724,523	539,689	539,689	\$ -			
2017	2,724,523	25,159	2,699,363	534,938	534,938				
2018	2,699,363	25,159	2,674,204	530,186	530,186	\$ -			
2019	2,674,204	25,159	2,649,045	525,435	525,435	\$ -			
2020	2,649,045	25,159	2,623,886	520,684	520,684	\$ -			
2021	2,623,886	25,159	2,598,727	515,932	515,932				
2022	2,598,727	25,159	2,573,568	511,181	511,181	\$ -			
2023	2,573,568	25,159	2,548,408	506,430		\$ -			
2024	2,548,408	25,159	2,523,249	501,678	501,678				
2025	2,523,249	25,159	2,498,090	496,927					
2026	2,498,090	25,159	2,472,931	492,176	492,176				
2027	2,472,931	25,159	2,447,772	487,424	487,424				
2028	2,447,772	25,159	2,422,613	482,673	482,673				
2029	2,422,613	25,159	2,397,453	477,922	477,922				
2030	2,397,453	25,159	2,372,294	473,170	473,170				
2031	2,372,294	25,159	2,347,135	468,419	468,419				
2032	2,347,135	25,159	2,321,976	463,668	463,668				
2033	2,321,976	25,159	2,296,817	458,916	458,916				
2034	2,296,817	25,159	2,271,658	454,165	454,165				
2035	2,271,658	25,159	2,246,499	449,414	449,414				
2036	2,246,499	25,159	2,221,339	444,662	444,662				
2037	2,221,339	25,159	2,196,180	439,911	439,911				
2038	2,196,180	25,159	2,171,021	435,160					
2039	2,171,021	25,159	2,145,862	430,408					
2040	2,145,862	25,159	2,120,703	425,657	425,657	\$ -			
2041	2,120,703	25,159	2,095,544	420,905	420,905	· ·			
2042	2,095,544	25,159		416,154					
2042	2,070,384	25,159	2,045,225	411,403	411,403				
2044	2,045,225	25,159		406,651	406,651				
2045	2,020,066	25,159		401,900	401,900				
2046	1,994,907	25,159		397,149	397,149				
2047	1,969,748	25,159		392,397	392,397				
2048	1,944,589	25,159	1,919,429	387,646	387,646				
2049	1,919,429	25,159	1,894,270	382,895	382,895				
2050	1,894,270	25,159 25,159	1,869,111	378,143	378,143				
2051	1,869,111	25,159 25,159	1,843,952	373,392	373,392				
2052	1,843,952	25,159 25,159	1,818,793	368,641	368,641				
2053	1,818,793	25,159 25,159		363,889	363,889				
2054	1,793,634	25,159 25,159		359,138	359,138				
2055	1,768,474	25,159 25,159		354,387	354,387				
2056	1,743,315	25,159 25,159		349,635	349,635				
2057	1,718,156	25,159 25,159		344,884	344,884				
2058	1,692,997	25,159 25,159		340,133	340,133				
2059	1,667,838	25,159 25,159	1,642,679	335,381	335,381				
2060	1,642,679	25,159 25,159	1,617,520	330,630	330,630				
2061	1,617,520	25,159 25,159	1,592,360	325,879	325,879				
2062	1,592,360	25,159 25,159	1,567,201	321,127	321,127				
2063	1,567,201	25,159 25,159		316,376	316,376				
2064	1,542,042	25,159 25,159		311,625	311,625				
2065	1,516,883	25,159 25,159		306,873	306,873				
2066	1,491,724	25,159 25,159		302,122	302,122				
2067	1,466,565	25,159 25,159		297,371	297,371				
2068	1,441,405	25,159 25,159	1,441,405 1,416,246	297,371	297,371				
2069	1,416,246	25,159 25,159	1,391,087	292,619	287,868				
2070	1,391,087	25,159 25,159	1,365,928	283,117	283,117				
2071	1,365,928	25,159 25,159	1,340,769	278,365	278,365				
2072	1,340,769	25,159 25,159		273,614	273,614				
Project Totals	1,340,709	25,159	1,313,010	27 3,014	27 3,014	Ψ -			

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

Project Totals

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

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

24,801,548

24,801,548

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

A. Base Plan Facilities

Facilities receiving incentives accepted by FERC in Docket No.

(e.g. ER05-925-000)

Current Projected Year ARR

Current Projected Year ARR w/ Incentive

Current Projected Year ARR w/ Incentive

RTEP ID: b1034.6 (138kV circuit breakers at South Canton Station)

Current Projected Year ARR w/ Incentive

Current Projected Year Incentive ARR

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

CUMULATIVE HISTORY OF PROJECTED ANNUAL REVENUE REQUIREMENTS:

LIFE OF THE PROJECT.

Detaile										
Details										
vestment	2,250,000	2,250,000 Current Year								
ervice Year (yyyy)	2013	2013 ROE increase accepted by FERC (Basis Points)								
ervice Month (1-12)	12	12 FCR w/o incentives, less depreciation								
seful life	44	44 FCR w/incentives approved for these facilities, less dep.								
IAC (Yes or No)	No	No Annual Depreciation Expense								
Investment	Beginning	Depreciation	Ending	RTEP Rev. Req't.	RTEP Rev. Req't.	Incentive Rev.				
Year	Balance	Expense	Balance	w/o Incentives	with Incentives **	Requirement ##				

							RTEP Projected	RTEP Projected	
Investment Year	Beginning Balance	Depreciation Expense	Ending Balance	RTEP Rev. Req't. w/o Incentives	RTEP Rev. Req't. with Incentives **	Incentive Rev. Requirement ##	Rev. Req't.From Prior Year Template w/o Incentives	Rev. Req't.From Prior Year Template with Incentives **	
2013	2,250,000	-	2,250,000	424,916	424,916	\$ -			
2014	2,250,000	25,159	2,224,841	445,323	445,323				
2015	2,224,841	25,159	2,199,682	440,572	440,572				
2016	2,199,682	25,159	2,174,523	435,821	435,821				
2017	2,174,523	25,159	2,149,363	431,069	431,069				
2018	2,149,363	25,159	2,124,204	426,318	426,318				
2019	2,124,204	25,159	2,099,045	421,567	421,567				
2020	2,099,045	25,159	2,073,886	416,815	416,815				
2021	2,073,886	25,159	2,048,727	412,064	412,064				
2022	2,048,727	25,159	2,023,568	407,313	407,313				
2023	2,023,568	25,159	1,998,408	402,561	402,561	\$ -			
2024	1,998,408	25,159	1,973,249	397,810	397,810	\$ -			
2025	1,973,249	25,159	1,948,090	393,059	393,059				
2026	1,948,090	25,159	1,922,931	388,307	388,307				
2027	1,922,931	25,159	1,897,772	383,556	383,556				
2028	1,897,772	25,159	1,872,613	378,805	378,805				
2029	1,872,613	25,159	1,847,453	374,053	374,053				
2030	1,847,453	25,159	1,822,294	369,302	369,302				
2031	1,822,294	25,159	1,797,135	364,551	364,551				
2032	1,797,135	25,159	1,771,976	359,799	359,799				
2033	1,771,976	25,159	1,746,817	355,048	355,048				
2034	1,746,817	25,159	1,721,658	350,297	350,297	\$ -			
2035	1,721,658	25,159	1,696,499	345,545	345,545	\$ -			
2036	1,696,499	25,159	1,671,339	340,794	340,794				
2037	1,671,339	25,159	1,646,180	336,043	336,043				
2038	1,646,180	25,159	1,621,021	331,291	331,291	\$ -			
2039	1,621,021	25,159	1,595,862	326,540	326,540	\$ -			
2040	1,595,862	25,159	1,570,703	321,789	321,789				
2041	1,570,703	25,159	1,545,544	317,037	317,037				
2042	1,545,544	25,159	1,520,384	312,286	312,286				
2043	1,520,384	25,159		307,535	307,535				
2044	1,495,225	25,159	1,470,066	302,783	302,783	\$ -			
2045	1,470,066	25,159	1,444,907	298,032	298,032				
2046	1,444,907	25,159	1,419,748	293,280	293,280				
2047	1,419,748	25,159	1,394,589	288,529	288,529				
2048	1,394,589	25,159	1,369,429	283,778	283,778				
2049	1,369,429	25,159	1,344,270	279,026	279,026				
2050	1,344,270	25,159	1,319,111	274,275	274,275				
2051	1,319,111	25,159	1,293,952	269,524	269,524				
2052	1,293,952	25,159	1,268,793	264,772	264,772				
2053	1,268,793	25,159	1,243,634	260,021	260,021				
2054	1,243,634	25,159	1,218,474	255,270	255,270				
2055	1,218,474	25,159	1,193,315	250,518	250,518				
2056	1,193,315		1,168,156	245,767	245,767				
2057	1,168,156	25,159	1,142,997	241,016	241,016				
2058	1,142,997	25,159	1,117,838	236,264	236,264				
2059	1,117,838	25,159	1,092,679	231,513	231,513				
2060	1,092,679	25,159	1,067,520	226,762	226,762				
2061	1,067,520	25,159	1,042,360	222,010	222,010				
2062	1,042,360	25,159	1,017,201	217,259	217,259				
2063	1,017,201	25,159	992,042	212,508	212,508				
2064	992,042	25,159	966,883	207,756	207,756				
2065	966,883	25,159	941,724	203,005	203,005				
2066	941,724	25,159	916,565	198,254	198,254				
2067	916,565	25,159	891,405	193,502	193,502				
2068	891,405	25,159	866,246	188,751	188,751				
2069	866,246	25,159	841,087	184,000	184,000				
2070	841,087	25,159	815,928	179,248	179,248				
2071	815,928	25,159	790,769	174,497	174,497				
2072	790,769		765,610	169,746	169,746				
Project Totals	•	•	•	19 560 453	19 560 453				

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

Project Totals

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

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

18,569,453

18,569,453

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

A. Base Plan Facilities

Facilities receiving incentives accepted by FERC in Docket No.

(e.g. ER05-925-000)

Current Projected Year ARR

Current Projected Year ARR w/ Incentive

RTEP ID: b1864.1 (Add two additional 345/138 kV transformers at Kammer)

333,178

Current Projected Year ARR w/ Incentive

Current Projected Year Incentive ARR

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

CUMULATIVE HISTORY OF PROJECTED ANNUAL REVENUE REQUIREMENTS:

LIFE OF THE PROJECT.

Details											
vestment	1,750,000	Current Year	rrent Year								
ervice Year (yyyy)	2013	ROE increase accepte	DE increase accepted by FERC (Basis Points)								
ervice Month (1-12)	11	FCR w/o incentives, les	R w/o incentives, less depreciation								
seful life	44	FCR w/incentives appr	R w/incentives approved for these facilities, less dep.								
IAC (Yes or No)	No	Annual Depreciation E	nnual Depreciation Expense								
Investment	Beginning	Depreciation	Ending	RTEP Rev. Req't.	RTEP Rev. Req't.	Incentive Rev.					
Year	Balance	Expense	Balance	w/o Incentives	with Incentives **	Requirement ##					
2013	1,750,000	3,314	1,746,686	333,178	333,178	\$ -					

Investment	Beginning	Depreciation	Ending	RTEP Rev. Req't.	RTEP Rev. Req't.	Incentive Rev.	RTEP Projected Rev. Req't.From Prior Year Template	 RTEP Projected Rev. Req't.From Prior Year Template	
Year	Balance	Expense	Balance	w/o Incentives	with Incentives **	Requirement ##	w/o Incentives	with Incentives **	
2013	1,750,000	3,314	1,746,686	333,178	333,178				
2014	1,746,686	25,159	1,721,526	350,272	350,272				
2015	1,721,526	25,159	1,696,367	345,520	345,520				
2016 2017	1,696,367 1,671,208	25,159 25,159	1,671,208 1,646,049	340,769 336,018	340,769 336,018				
2017	1,646,049	25,159 25,159	1,620,890	331,266	331,266				
2019	1,620,890	25,159	1,595,731	326,515	326,515				
2020	1,595,731	25,159	1,570,571	321,764	321,764				
2021	1,570,571	25,159	1,545,412	317,012	317,012				
2022	1,545,412	25,159	1,520,253	312,261	312,261				
2023	1,520,253	25,159	1,495,094	307,510	307,510				
2024	1,495,094	25,159	1,469,935	302,758	302,758				
2025	1,469,935	25,159	1,444,776	298,007	298,007				
2026	1,444,776	25,159	1,419,617	293,256	293,256				
2027 2028	1,419,617	25,159 25,150	1,394,457	288,504	288,504 283,753				
2028	1,394,457 1,369,298	25,159 25,159	1,369,298 1,344,139	283,753 279,002	283,753 279,002				
2029	1,344,139	25,159 25,159	1,318,980	279,002 274,250	279,002 274,250				
2030	1,318,980	25,159 25,159	1,293,821	269,499	269,499				
2032	1,293,821	25,159	1,268,662	264,748	264,748				
2033	1,268,662	25,159	1,243,502	259,996	259,996				
2034	1,243,502	25,159	1,218,343	255,245	255,245				
2035	1,218,343	25,159	1,193,184	250,494	250,494				
2036	1,193,184	25,159	1,168,025	245,742	245,742				
2037	1,168,025	25,159	1,142,866	240,991	240,991				
2038	1,142,866	25,159	1,117,707	236,240	236,240				
2039	1,117,707	25,159	1,092,547	231,488	231,488				
2040	1,092,547	25,159	1,067,388	226,737	226,737				
2041	1,067,388	25,159	1,042,229	221,986	221,986				
2042 2043	1,042,229 1,017,070	25,159 25,150	1,017,070 991,911	217,234 212,483	217,234 212,483				
2044	991,911	25,159 25,159	966,752	207,732	207,732				
2045	966,752	25,159	941,593	202,980	202,980				
2046	941,593	25,159	916,433	198,229	198,229				
2047	916,433	25,159	891,274	193,478	193,478				
2048	891,274	25,159	866,115	188,726	188,726				
2049	866,115	25,159	840,956	183,975	183,975				
2050	840,956	25,159	815,797	179,224	179,224				
2051	815,797	25,159	790,638	174,472	174,472				
2052	790,638	25,159	765,478	169,721	169,721				
2053	765,478	25,159	740,319	164,969	164,969				
2054	740,319	25,159	715,160	160,218	160,218				
2055 2056	715,160 690,001	25,159 25,159	690,001 664,842	155,467 150,715	155,467 150,715				
2056 2057	690,001 664,842	25,159 25,159	639,683	150,715 145,964	150,715 145,964				
2057	639,683	25,159 25,159	614,523	141,213	141,213				
2059	614,523	25,159	589,364	136,461	136,461				
2060	589,364	25,159	564,205	131,710	131,710				
2061	564,205	25,159	539,046	126,959	126,959				
2062	539,046	25,159	513,887	122,207	122,207	\$ -			
2063	513,887	25,159	488,728	117,456	117,456				
2064	488,728	25,159	463,568	112,705	112,705				
2065	463,568	25,159	438,409	107,953	107,953				
2066	438,409	25,159	413,250	103,202	103,202				
2067	413,250	25,159	388,091	98,451	98,451				
2068	388,091	25,159 25,150	362,932 337,773	93,699	93,699 88,048				
2069 2070	362,932 337,773	25,159 25,159	337,773 312,614	88,948 84,197	88,948 84,197				
2070	337,773 312,614	25,159 25,159	287,454	79,445	79,445				
2071	287,454	25,159 25,159	262,295	74,694	74,694				
Project Totals	,	==,:30	,	12,869,670	12,869,670	-			
,				,000,070	. =,000,070				

** 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.

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

A. Base Plan Facilities

Facilities receiving incentives accepted by FERC in Docket No. (e.g. ER05-925-000))	Current Projected			-			
Project Description:							_	Year ARR w/ Incentive Year Incentive ARR		<u>.</u>	}
Details]				
Investment		Current Year				2013	CUMUL	ATIVE HISTORY OF P	ROJECTED ANNUAL	REVENUE REQUIRE	MENTS:
Service Year (yyyy) Service Month (1-12) Useful life CIAC (Yes or No)	12 44	ROE increase accepte FCR w/o incentives, le FCR w/incentives appl Annual Depreciation E	ess depreciation roved for these facilities	•		- 18.89% 18.89% -	INPUT PROJE	TORY OF PROJECTED ECTED ARR (WITH & V ELOW TO MAINTAIN H PROJECT.	VITHOUT INCENTIVES	S) FROM EACH PRIO	
Investment Year	Beginning Balance	Depreciation Expense	Ending Balance	RTEP Rev. Req't. w/o Incentives	RTEP Rev. Req't. with Incentives **	Incentive Rev. Requirement ##	RTEP Projected Rev. Req't.From Prior Year Templat w/o Incentives	е	RTEP Projected Rev. Req't.From Prior Year Template with Incentives **		
2013	-	-	-	-	-	\$ -					
2014	-	-	-	-	-	\$ -					
2015	-	-	-	-	-	\$ -					
2016	-	-	-	-	-	-					
2017	-	-	-	-	-	-					
2018	-	-	-	-	-	-					
2019	-	-	-	-	-	5 -					
2020	-	-	-	-	-	5 -					

2018	_	_	_	_	_	\$ -			
2019	_	_	_	_	_	\$ - \$ -			
2019						Φ			
2020	-	-	-	-	-	\$ -			
2021	-	-	-	-	-	\$ -			
2022	-	-	-	-	-	\$ -			
2023	-	-	-	-	-	\$ -			
2024	_	_	_	_	_	\$ -			
2025	_	_	_	_	_	\$ -			
2025									
2026	-	-	-	-	-	\$ -			
2027	-	-	-	-	-	\$ -			
2028	-	-	-	-	-	\$ -			
2029	-	_	_	_	-	\$ -			
2030	_	_	_	_	_	\$ -			
2031		_	_	_	_				
2031	-					\$ -			
2032	-	-	-	-	-	\$ -			
2033	-	-	-	-	-	\$ -			
2034	-	-	-	-	-	\$ -			
2035	-	-	-	-	-	\$ -			
2036	_	_	_	_	_	\$ -			
2037	_	_	_	_	_				
2037									
2038	-	-	-	-	-	\$ -			
2039	-	-	-	-	-	\$ -			
2040	-	-	-	-	-	\$ -			
2041	-	_	_	_	-	\$ -			
2042	_	_	_	_	_	\$ -			
2043	_	_	_	_	_	\$ -			
2043						φ -			
2044	-	-	-	-	-	\$ -			
2045	-	-	-	-	-	\$ -			
2046	-	-	-	-	-	\$ -			
2047	-	-	-	-	-	\$ -			
2048	-	_	_	-	-	\$ -			
2049	_	_	_	_	_	\$ -			
2050	_	_	_	_	_	\$ -			
2050					-				
2051	-	-	-	-	-	\$ -			
2052	-	-	-	-	-	\$ -			
2053	-	-	-	-	-	\$ -			
2054	-	-	-	-	-	\$ -			
2055	_	_	_	_	_	\$ -			
2056	_	_	_	_	l _	\$ -			
2057									
2057	-	-	-	-	-	\$ -			
2058	-	-	-	-	-	\$ -			
2059	-	-	-	-	-	\$ -			
2060	-	-	-	-	-	\$ -			
2061	-	-	-	-	-	\$ -			
2062	_	_	_	_	_	\$ -			
2063	_	_	_	_	_	\$ -			
2064	-	-	-	-	-	\$ -			
2065	-	-	-	-	-	\$ -			
2066	-	-	-	-	-	\$ -			
2067	-	-	-	-	-	\$ -			
2068	_	_	_	_	_	\$ -			
2069	_	_	_	_	_	\$ -			
2009						-			
2070	-	-	-	-	-	\$ -			
2071	-	-	-	-	-	\$ -			
2072	-	-	-	-	-	\$ -			
Project Totals				-	-	-	· -		
-,									

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

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

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

AEP East Companies Cost of Service Formula Rate Using 2012 FF1 Balances Worksheet K Supporting Calculation of TRUE-UP PJM RTEP Project Revenue Requirement Billed to Benefiting Zones OHIO POWER COMPANY

Page 1 of 7

Ι.

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

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

ROE w/o incentives (True-Up TCOS, In 164) 11.49% Project ROE Incentive Adder 0 <==ROE Adder Cannot Exceed 100 Basis Points 11.49% <== ROE Including Incentives Cannot Exceed 12.5% Until July 1, 2012 ROE with additional 0 basis point incentive Determine R (cost of long term debt, cost of preferred stock and equity percentage is from the True-Up TCOS, lns 162 through 164) Cost Weighted cost 5.49% 2.692% Long Term Debt 49.00% 0.00% Preferred Stock 0.00% 0.000% Common Stock 51.00% 11.49% 5.860%

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

 Rate Base (True-Up TCOS, In 78)
 973,996,207

 R (from A. above)
 8.552%

 Return (Rate Base x R)
 83,293,333

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

Return (from B. above)	83,293,333
Effective Tax Rate (True-Up TCOS, In 126)	38.18%
Income Tax Calculation (Return x CIT)	31,800,286
ITC Adjustment	(347,126)
Income Taxes	31,453,160

II. Calculate Net Plant Carrying Charge Rate (Fixed Charge Rate or FCR) with hypothetical 0 basis point ROE increase.

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

Annual Revenue Requirement (True-Up TCOS, In 1)	262,126,968
T.E.A. & Lease Payments (True-Up TCOS, Lns 105 & 106)	1.351.836
Return (True-Up TCOS, In 134)	83.293.333
, ,	,,
Income Taxes (True-Up TCOS, In 133)	31,453,160
Annual Revenue Requirement, Less TEA Charges,	146,028,639

B. Determine Annual Revenue Requirement with hypothetical 0 basis point increase in ROE.

Annual Revenue Requirement, Less TEA Charges, Return and Taxes	146,028,639
Return (from I.B. above)	83,293,333
Income Taxes (from I.C. above)	31,453,160
Annual Revenue Requirement, with 0 Basis Point ROE increase	260,775,132
Depreciation (True-Up TCOS, In 111)	43,487,185
Annual Rev. Req, w/ 0 Basis Point ROE increase,	217,287,947
less Depreciation	

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

Net Transmission Plant (True-Up TCOS, In 48) Annual Revenue Requirement, with 0 Basis Point ROE increase FCR with 0 Basis Point increase in ROE	1,136,509,025 260,775,132 22.95%
Annual Rev. Req, w / 0 Basis Point ROE increase, less Dep.	217,287,947
FCR with 0 Basis Point ROE increase, less Depreciation	19.12%
FCR less Depreciation (True-Up TCOS, ln 9)	<u>19.12%</u>
Incremental FCR with 0 Basis Point ROE increase,	0.00%
less Depreciation	

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)):	1,942,327,221 2,007,735,450
Subtotal	3,950,062,671
Average Transmission Plant Balance for	1,975,031,336
Annual Depreciation Rate (True-Up TCOS, In 111)	44,851,117
Composite Depreciation Rate	2.27%
Depreciable Life for Composite Depreciation Rate	44.04
Round to nearest whole year	44

SUMMARY OF TRUED-UP ANNUAL REVENUE REQUIREMENTS FOR RTEPPROJECTS Rev Require W Incentives Incentive Amounts										
TRUE-UP YEAR	2012	·								
	As Projected in Prior Year WS J	\$	2,264,500	\$	2,264,500	\$	-			
	Actual after True-up	\$	1,248,552	\$	1,248,552	\$	-			
	True-up of ARR For 2012		(1,015,948)		(1,015,948)		-			

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)

RTEP ID: b504 (765 kV circuit breaker installations at Hanging Rock) **Project Description:**

2012 Rev Require W Incentives Incentive Amounts Prior Yr Projected 1,057,666 1,057,666 1,099,203 Prior Yr True-Up 1,099,203 True-Up Adjustment 41,537 41,537

Details								
Investment	5,491,719	Current Year				2012		
Service Year (yyyy)	2009	ROE increase accepted	DE increase accepted by FERC (Basis Points)					
Service Month (1-12)	4	FCR w/o incentives, les	CR w/o incentives, less depreciation					
Useful life	44	FCR w/incentives appro	CR w/incentives approved for these facilities, less dep.					
CIAC (Yes or No)	No	Annual Depreciation Ex	nual Depreciation Expense					

2012	
-	CUMULA [*]
19.12%	INPL
19.12%	TEM

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

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

CIAC (Yes or No)	No.	Annual Depreciation E	xpense				124,812		LIFE OF THE PROJ	ECT.			
									RTEP Projected Rev.		RTEP Projected		
<u>'</u>								R	•	RTEP Rev Req't True-	Rev. Req't.From	RTEP Rev Req't	
Investment	Beginning	Depreciation	Ending	Average	RTEP Rev. Req't.	RTEP Rev. Req't.	Incentive Rev.		WS J	up	Prior Year WS J	True-up	True-up of Incentive
Year	Balance	Expense	Balance	Balance	w/o Incentives	with Incentives **	Requirement ##	L	w/o Incentives	w/o Incentives	with Incentives **	with Incentives **	with Incentives **
2009	5,491,719	83,208	5,408,511	5,450,115	1,125,210	1,125,210	\$ -	\$	894,796				
2010	5,408,511	124,812	5,283,699	5,346,105	1,146,928	1,146,928		\$	1,094,271				
2011	5,283,699	124,812	5,158,888	5,221,293	1,123,065	1,123,065		\$	1,210,680				
2012	5,158,888	124,812	5,034,076	5,096,482	1,099,203	1,099,203		\$	1,057,666	\$ 41,537	\$ 1,057,666	\$ 41,537	\$ -
2013	5,034,076	124,812	4,909,264	4,971,670	1,075,340	1,075,340				\$ -		\$ -	\$ -
2014	4,909,264	124,812	4,784,452	4,846,858	1,051,477	1,051,477				\$ -		\$ -	\$ -
2015	4,784,452	124,812	4,659,640	4,722,046	1,027,615	1,027,615				\$ -		\$ -	\$ -
2016	4,659,640	124,812	4,534,829	4,597,234	1,003,752	1,003,752				\$ -		\$ -	\$ -
2017	4,534,829	124,812	4,410,017	4,472,423	979,890	979,890				\$ -		\$ -	\$ -
2018	4,410,017	124,812	4,285,205	4,347,611	956,027	956,027				\$ -		\$ -	\$ -
2019	4,285,205	124,812	4,160,393	4,222,799	932,164	932,164				\$ -		\$ -	\$ -
2020	4,160,393	124,812	4,035,581	4,097,987	908,302	908,302				\$ -		\$ -	\$ -
2021	4,035,581	124,812	3,910,770	3,973,175	884,439	884,439				\$ -		\$ -	\$ -
2022	3,910,770	124,812	3,785,958	3,848,364	860,576	860,576				\$ -		\$ -	\$ -
2023	3,785,958	124,812	3,661,146	3,723,552	836,714	836,714				\$ -		\$ -	\$ -
2024	3,661,146	124,812	3,536,334	3,598,740	812,851	812,851				\$ -		\$ -	\$ -
2025	3,536,334	124,812	3,411,522	3,473,928	788,988	788,988				\$ -		\$ -	\$ -
2026	3,411,522	124,812	3,286,711	3,349,117	765,126	765,126				\$ -		\$ -	\$ -
2027	3,286,711	124,812	3,161,899	3,224,305	741,263	741,263				\$ -		\$ -	\$ -
2028	3,161,899	124,812	3,037,087	3,099,493	717,401	717,401	\$ -			\$ -		\$ -	\$ -
2029	3,037,087	124,812	2,912,275	2,974,681	693,538	693,538	\$ -			\$ -		\$ -	\$ -
2030	2,912,275	124,812	2,787,463	2,849,869	669,675	669,675	\$ -			\$ -		\$ -	\$ -
2031	2,787,463	124,812	2,662,652	2,725,058	645,813	645,813	\$ -			\$ -		\$ -	\$ -
2032	2,662,652	124,812	2,537,840	2,600,246	621,950	621,950	\$ -			\$ -		\$ -	\$ -
2033	2,537,840	124,812	2,413,028	2,475,434	598,087	598,087	\$ -			\$ -		\$ -	\$ -
2034	2,413,028	124,812	2,288,216	2,350,622	574,225	574,225				\$ -		\$ -	\$ -
2035	2,288,216	124,812	2,163,404	2,225,810	550,362	550,362	\$ -			\$ -		\$ -	\$ -
2036	2,163,404	124,812	2,038,593	2,100,999	526,499	526,499				\$ -		\$ -	\$ -
2037	2,038,593	124,812	1,913,781	1,976,187	502,637	502,637	\$ -			\$ -		\$ -	\$ -
2038	1,913,781	124,812	1,788,969	1,851,375	478,774	478,774	\$ -			\$ -		\$ -	\$ -
2039	1,788,969	124,812	1,664,157	1,726,563	454,912	454,912				\$ -		\$ -	\$ -
2040	1,664,157	124,812	1,539,345	1,601,751	431,049	431,049				\$ -		\$ -	\$ -
2041	1,539,345	124,812	1,414,534	1,476,940	407,186	407,186				\$ -		\$ -	\$ -
2042	1,414,534	124,812	1,289,722	1,352,128	383,324	383,324	\$ -			\$ -		\$ -	\$ -
2043	1,289,722	124,812	1,164,910	1,227,316	359,461	359,461				\$ -		\$ -	\$ -
2044	1,164,910	124,812	1,040,098	1,102,504	335,598	335,598				\$ -		\$ -	\$ -
2045	1,040,098	124,812	915,286	977,692	311,736	311,736				\$ -		\$ -	\$ -
2046	915,286	124,812	790,475	852,881	287,873	287,873				\$ -		\$ -	\$ -
2047	790,475	124,812	665,663	728,069	264,010	264,010				\$ -		\$ -	\$ -
2048	665,663	124,812	540,851	603,257	240,148	240,148				\$ -		\$ -	\$ -
2049	540,851	124,812	416,039	478,445	216,285	216,285				\$ -		\$ -	\$ -
2050	416,039	124,812	291,228	353,633	192,423	192,423				\$ -		\$ -	\$ -
2051	291,228	124,812	166,416	228,822	168,560	168,560				\$ -		-	\$ -
2052	166,416	124,812	41,604	104,010	144,697	144,697				\$ -		\$ -	\$ -
2053	41,604	41,604	-	20,802	45,581	45,581				\$ -		-	\$ -
2054	-	-	-	,	-	-	\$ -			\$ -		-	\$ -
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** This is the total amount that needs to be reported to PJM for billing to all regions.

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

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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)

(e.g. ER05-92

4,166,424

4,166,424

Project Description:

RTEP ID: B1231 (Replace the existing 138/69-12 kV transformer at West Moulton Station with a 138/69 kV transformer and a 69/12 kV transformer)

2012	Rev Require	W Incentives	Incentive Amounts
Prior Yr Projected	832,082	832,082	-
Prior Yr True-Up	149,349	149,349	-
True-Up Adjustment	(682,733)	(682,733)	-

Details								
Investment	774,225	Current Year	nt Year					
Service Year (yyyy)	2012	ROE increase accepted by FERC (Basis Points)	DE increase accepted by FERC (Basis Points)					
Service Month (1-12)	11	FCR w/o incentives, less depreciation	CR w/o incentives, less depreciation					
Useful life	44	FCR w/incentives approved for these facilities, less dep.	CR w/incentives approved for these facilities, less dep.					
CIAC (Yes or No)	No	Annual Depreciation Expense	17,596					

e Month (1-12)		FCR w/o incentives, les	•	loss den			19.12
life (Yes or No)		FCR w/incentives appro Annual Depreciation Ex		iess dep.			19.12 17,59
,		,	•				,
Investment	Beginning	Depreciation	Ending	Average	RTEP Rev. Reg't.	RTEP Rev. Reg't.	Incentive Rev.
Year	Balance	Expense	Balance	Balance	w/o Incentives	with Incentives **	Requirement ##
2012	774,225	1,466	772,759	773,492	149,349	149,349	\$ -
2013	772,759	17,596	755,163	763,961	163,657	163,657	\$ -
2014	755,163	17,596	737,567	746,365	160,293	160,293	¢
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2015	737,567	17,596	719,971	728,769	156,929	156,929	5 -
2016	719,971	17,596	702,375	711,173	153,564	153,564	-
2017	702,375	17,596	684,779	693,577	150,200	150,200	\$ -
2018	684,779	17,596	667,183	675,981	146,836	146,836	\$ -
2019	667,183	17,596	649,587	658,385	143,472	143,472	\$ -
2020	649,587	17,596	631,990	640,788	140,108	140,108	\$ -
2021	631,990	17,596	614,394	623,192	136,744	136,744	\$ -
2022	614,394	17,596	596,798	605,596	133,379	133,379	\$ -
2023	596,798	17,596	579,202	588,000	130,015	130,015	¢ _
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2024	579,202	17,596	561,606	570,404	126,651	126,651	φ -
2025	561,606	17,596	544,010	552,808	123,287	123,287	5 -
2026	544,010	17,596	526,414	535,212	119,923	119,923	\$ -
2027	526,414	17,596	508,818	517,616	116,559	116,559	\$ -
2028	508,818	17,596	491,222	500,020	113,194	113,194	\$ -
2029	491,222	17,596	473,626	482,424	109,830	109,830	\$ -
2030	473,626	17,596	456,030	464,828	106,466	106,466	\$ -
2031	456,030	17,596	438,434	447,232	103,102	103,102	\$ -
2032	438,434	17,596	420,838	429,636	99,738	99,738	¢ .
2032	420,838	17,596	403,242	412,040	96,374	96,374	φ •
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2034	403,242	17,596	385,646	394,444	93,009	93,009	-
2035	385,646	17,596	368,050	376,848	89,645	89,645	-
2036	368,050	17,596	350,454	359,252	86,281	86,281	\$ -
2037	350,454	17,596	332,858	341,656	82,917	82,917	\$ -
2038	332,858	17,596	315,262	324,060	79,553	79,553	\$ -
2039	315,262	17,596	297,666	306,464	76,189	76,189	\$ -
2040	297,666	17,596	280,070	288,868	72,824	72,824	\$ -
2041	280,070	17,596	262,474	271,272	69,460	69,460	\$ -
2042	262,474	17,596	244,878	253,676	66,096	66,096	\$ -
2042	244,878	17,596	227,282	236,080	62,732	62,732	
2044	227,282	17,596	209,686	218,484	59,368	59,368	-
2045	209,686	17,596	192,090	200,888	56,004	56,004	-
2046	192,090	17,596	174,494	183,292	52,639	52,639	\$ -
2047	174,494	17,596	156,898	165,696	49,275	49,275	\$ -
2048	156,898	17,596	139,302	148,100	45,911	45,911	\$ -
2049	139,302	17,596	121,706	130,504	42,547	42,547	\$ -
2050	121,706	17,596	104,110	112,908	39,183	39,183	\$ -
2051	104,110	17,596	86,514	95,312	35,819	35,819	\$ -
2052	86,514	17,596	68,918	77,716	32,454	32,454	-
2052	68,918	17,596	51,322	60,120	29,090	29,090	Īě
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2054	51,322	17,596	33,726	42,524	25,726	25,726	\$ -
2055	33,726	17,596	16,130	24,928	22,362	22,362	-
2056	16,130	16,130	-	8,065	17,672	17,672	\$ -
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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.

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		RTEP Projected Rev.	DTED Day Daylt True	RTEP Projected	DTED Day Dayle	
		Req't.From Prior Year	RTEP Rev Req't True-		RTEP Rev Req't	T
/ .		WS J	up	Prior Year WS J	True-up	True-up of Incentive
##		w/o Incentives	w/o Incentives	with Incentives **	with Incentives **	with Incentives **
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Project Totals

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

Page 3 of 7

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

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) 2013 Rev Require W Incentives Incentive Amounts Prior Yr Projected 374,752 374,752 RTEP ID: b0570 (Reconductor EAST LIMA-STERLING 138 KV LINE) Prior Yr True-Up **Project Description:**

Details			
Investment	-	Current Year	2013
Service Year (yyyy)	2013	ROE increase accepted by FERC (Basis Points)	-
Service Month (1-12)	6	FCR w/o incentives, less depreciation	19.12%
Useful life	44	FCR w/incentives approved for these facilities, less dep.	19.12%
CIAC (Yes or No)	No	Annual Depreciation Expense	-

TRUE UP OF PROJECT REVENUE REQUIREMENT FOR P	RIOR YEAR:

(374,752)

(374,752)

True-Up Adjustment

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

The content	Useful life CIAC (Yes or No)	44 No	FCR w/incentives app	proved for these facilities	, less dep.			19.12%		W TO MAINTAIN HISTOR'	Y OF TRUED-UP ARR	S OVER THE	
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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.

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

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) 2013 Rev Require W Incentives Incentive Amounts **Project Description:** RTEP ID: b1034.1 (South Canton - West Canton 138kV line (replacing Torrey - West Canton) and Wagenhals – Wayview 138kV)

Details			
Investment	-	Current Year	2013
Service Year (yyyy)	2013	ROE increase accepted by FERC (Basis Points)	-
Service Month (1-12)	12	FCR w/o incentives, less depreciation	19.12%
Useful life	44	FCR w/incentives approved for these facilities, less dep.	19.12%
CIAC (Yes or No)	No	Annual Depreciation Expense	-

Prior Yr Projected	-	-	-
Prior Yr True-Up		-	-
True-Up Adjustment		-	-

CUMULATIVE HISTORY OF TRUED-UP ANNUAL REVENUE REQUIREMENTS:	
INPUT TRUE-UP ARR (WITH & WITHOUT INCENTIVES) FROM EACH PRIOR YEAR	2
TEMPLATE BELOW TO MAINTAIN HISTORY OF TRUED-UP ARRS OVER THE	
LIFE OF THE PROJECT.	

TRUE UP OF PROJECT REVENUE REQUIREMENT FOR PRIOR YEAR:

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Project Totals

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

OPCo WS K TRUE-UP RTEP RR Page 38 of 46

Page 5 of 7

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

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) 2013 Rev Require W Incentives Incentive Amounts Prior Yr Projected Prior Yr True-Up **Project Description:** RTEP ID: b1034.6 (138kV circuit breakers at South Canton Station) True-Up Adjustment

Details		
Investment	- Current Year	2013
Service Year (yyyy)	2013 ROE increase accepted by FERC (Basis Points)	-
Service Month (1-12)	12 FCR w/o incentives, less depreciation	19.12%
Useful life	FCR w/incentives approved for these facilities, less dep.	19.12%
CIAC (Yes or No)	No Annual Depreciation Expense	-

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UP OF PROJECT REVENUE REQUIREMENT FOR PRIOR YEAR:

HISTORY OF TRUED-UP ANNUAL REVENUE REQUIREMENTS: UE-UP ARR (WITH & WITHOUT INCENTIVES) FROM EACH PRIOR YEAR BELOW TO MAINTAIN HISTORY OF TRUED-UP ARRS OVER THE

Useful life 44 FCR w/incentives approved for these facilities, less dep. 19.12% CIAC (Yes or No) No Annual Depreciation Expense -												
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Year	Balance	Expense	Balance	Balance	w/o Incentives	with Incentives **	Requirement ##	w/o Incentives	w/o Incentives	with Incentives **	with Incentives **	with Incentives **
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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.

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Page 6 of 7

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

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) Rev Require 2013 W Incentives Incentive Amounts Prior ` Prior True-U **Project Description:** RTEP ID: b1864.1 (Add two additional 345/138 kV transformers at Kammer)

Details		
Investment	- Current Year	2013
Service Year (yyyy)	2013 ROE increase accepted by FERC (Basis Points)	-
Service Month (1-12)	12 FCR w/o incentives, less depreciation	19.12%
Useful life	FCR w/incentives approved for these facilities, less dep.	19.12%
CIAC (Yes or No)	No Annual Depreciation Expense	-

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

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

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

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) Rev Require 2013 W Incentives Incentive Amounts **Project Description:**

Details		
Investment	- Current Year	2013
Service Year (yyyy)	2013 ROE increase accepted by FERC (Basis Points)	-
Service Month (1-12)	12 FCR w/o incentives, less depreciation	19.12%
Useful life	FCR w/incentives approved for these facilities, less dep.	19.12%
CIAC (Yes or No)	No Annual Depreciation Expense	-

Prior Yr Projected	-	-	-
Prior Yr True-Up	 -	-	-
True-Up Adjustment	-	-	-

TRUE UP OF PROJECT REVENUE REQUIREMENT FOR PRIOR YEAR:

Page 7 of

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.

CIAC (Tes of No)	110	No Annual Depreciation Expense				RTEP Projected Rev.	201.	DTED Drainated			
								RIEP Projected Rev.		RTEP Projected	
									RTEP Rev Req't True-	Rev. Req't.From	RTEP Rev Req't
Investment	Beginning	Depreciation	Ending	Average	RTEP Rev. Req't.	RTEP Rev. Req't.	Incentive Rev.	WS J	up	Prior Year WS J	True-up
Year	Balance	Expense	Balance	Balance	w/o Incentives	with Incentives **	Requirement ##	w/o Incentives	w/o Incentives	with Incentives **	with Incentives **
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Project Totals

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

OPCo WS K TRUE-UP RTEP RR Page 41 of 46

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

AEP East Companies Cost of Service Formula Rate Using 2012 FF1 Balances Worksheet L Supporting Projected Cost of Debt OHIO POWER COMPANY

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

Lina	(A)	(B)	(C)	(D)	(E)
<u>Line</u> Number	<u>Issuance</u>	Principle Outstanding	Interest Rate	Annual Expense (See Note S on Projected Template)	<u>Notes</u>
1 2	Long Term Debt (FF1.p. 256-257.h) Fixed Rate Prom. Notes Payable to Parent	200,000,000	5.250%	10,500,000	
3					
4	Installment Purchase Contracts (FF1.p. 256-257.h, a)	(05,000,000)	0.0000/	(405,000)	
5	Reacquired Bonds Marshall County Series F	(35,000,000)	0.300%	(105,000)	
6 7	Reacquired Bonds:Marshall County Series E Reacquired Bonds:Ohio Air Quality Series 2005A	(50,000,000) (54,500,000)	0.950% 0.350%	(475,000) (190,750)	
8	Reacquired Bonds: Ohio Air Quality Series 2005A	(54,500,000)	0.350%	(190,750)	
9	Reacquired Bonds: Air Quality Series 2005C	(54,500,000)	0.350%	(190,750)	
10	Reacquired Bonds: Air Quality Series 2005D	(54,500,000)	0.350%	(190,750)	
11	WV Economic Development Mitchell Series 2008A	(65,000,000)	0.170%	(110,500)	
12	WV Economic Development Sporn Series 2008C	(50,000,000)	0.100%	(50,000)	
13	Ohio Air Quality Revenue Bonds Series 2007A	(44,500,000)	0.280%	(124,600)	
14	Ohio Air Quality Revenue Bonds Series 2007B	56,000,000	5.100%	2,856,000	
15	Ohio Air Quality Revenue Bonds Series 2009A	60,000,000	3.875%	2,325,000	
16	Ohio Air Quality Revenue Bonds Series 2009B	32,245,000	5.800%	1,870,210	
17	Ohio Air Quality Series C	50,000,000	5.150%	2,575,000	
18	Marshall County Series F	35,000,000	0.300%	105,000	
19	Marshall County Series E	50,000,000	0.950%	475,000	
20	Mitchell Series 2007A	65,000,000	4.900%	3,185,000	
21	Reacquired Bonds:Ohio Air Quality Series 2005A	54,500,000	0.350%	190,750	
22	Reacquired Bonds:Ohio Air Quality Series 2005B	54,500,000	0.350%	190,750	
23	Reacquired Bonds: Air Quality Series 2005C	54,500,000	0.350%	190,750	
24	Reacquired Bonds: Air Quality Series 2005D	54,500,000	0.350%	190,750	
25	WV Economic Development Amos Series 2010A	86,000,000	3.125%	2,687,500	
26	Ohio Air Quality Cavin Series 2010A	79,450,000	3.250%	2,582,125	
27 28	Ohio Air Quality Gavin Series 2010A WV Economic Development Mitchell Series 2008A	39,130,000 65,000,000	2.875% 0.170%	1,124,988 110,500	
20 29	WV Economic Development Kammer Series 2008A WV Economic Development Kammer Series 2008B	50,000,000	0.170%	65,000	
30	WV Economic Development Sporn Series 2008C	50,000,000	0.100%	50,000	
31	Ohio Air Quality Revenue Bonds Series 2007A	44,500,000	0.280%	124,600	
32	Unsecured Medium Series A - Due 2013	250,000,000	5.500%	13,750,000	
33	Unsecured Medium Series B - Due 2033	250,000,000	6.600%	16,500,000	
34	Unsecured Medium Series F - Due 2035	250,000,000	5.850%	14,625,000	
35	Unsecured Medium Series G - Due 2018	350,000,000	6.050%	21,175,000	
36	Unsecured Medium Term Notes Series F due 02/2013	250,000,000	5.500%	13,750,000	
37	Unsecured Medium Term Notes Series G due 02/2033	250,000,000	6.600%	16,500,000	
38	Unsecured Medium Term Notes Series H due 01/2014	225,000,000	4.850%	10,912,500	
39	Unsecured Medium Term Notes Series I due 07/2033	225,000,000	6.375%	14,343,750	
40	Unsecured Medium Term Notes Series K due 06/2016	350,000,000	6.000%	21,000,000	
41	Unsecured Medium Term Notes Series L due 09/2013	250,000,000	5.750%	14,375,000	
42	Senior Unsecured Note Series M	500,000,000	5.375%	26,875,000	
43	Issuance Discount, Premium, & Expenses:				
44	Auction Fees	FF1.p. 256 & 257.Lines Described as F	ees	-	
45	Allowable Hedge Amortization (See Ln 62 Below)	•		(2,097,663)	
46	Amort of Debt Discount and Expenses	FF1.p. 117.63.c		3,978,647	
47	Amort of Debt Premimums (Enter Negative)	FF1.p. 117.65.c		-	
48	Reacquired Debt:				
49	Amortization of Loss	FF1.p. 117.64.c		1,336,128	
50	Amortization of Gain	FF1.p. 117.66.c		-	
51	Total Interest on Long Term Debt	3,867,825,000	5.61%	216,794,185	
52	Preferred Stock (FF1.p. 250-251)	Preferred Shares Outstanding			
53		-	0.00%	-	
54 55		-	0.00%	-	
55 56			0.00% 0.00%		
57	Dividends on Preferred Stock	-	0.00%	-	
E0	Not Total Hadge Coins and Lasses (MC M. La CO. (E))			(0.007.000)	
58 50	Net Total Hedge Gains and Losses (WS M, Ln 30, (E))	nd TCOS In 165\		(2,097,663)	
59 60	Total Projected Capital Structure Balance for 2013 (Projecte Financial Hedge Recovery Limit - Five Basis Points of Total	· · · · · · · · · · · · · · · · · · ·		8,520,545,406 0.0005	
61	Limit of Recoverable Amount	Capital		4,260,273	
62	Recoverable Hedge Amortization (Lesser of Ln 58 or Ln	n 61)		(2,097,663)	
		- /		(=,00.,000)	

AEP East Companies Transmission Cost of Service Formula Rate OHIO POWER COMPANY

Worksheet M Supporting Calculation of Capital Structure and Weighted Average Cost of Capital Based on Average of Balances At 12/31/2011 & 12/31/2012

(A)	(B)	(C)	(D)	(E)
Line		Balances @ 12/31/2012	Balances @ 12/31/2011	Average
<u>Devel</u>	opment of Average Balance of Common Equity			
	1 Proprietary Capital (112.16.c&d)	4,489,200,654	4,413,669,464	4,451,435,059
	2 Less Preferred Stock (Ln 55 Below)	0	0	-
	3 Less Account 216.1 (112.12.c&d)	2,204,800	2,204,800	2,204,800
	4 Less Account 219.1 (112.15.c&d)	(165,724,552)	(197,721,635)	(181,723,094)
	5 Average Balance of Common Equity	4,652,720,406	4,609,186,299	4,630,953,353
Dovok	opment of Cost of Long Term Debt Based on Average	o Outstanding Ralance		
Devel	opinent of Cost of Long Term Debt Based on Average	e Outstanding Dalance	2	
	6 Bonds (112.18.c&d)	-	-	-
	7 Less: Reacquired Bonds (112.19.c&d)	462,500,000	418,000,000	440,250,000
	8 LT Advances from Assoc. Companies (112.20.c&d)	200,000,000	200,000,000	200,000,000
	9 Senior Unsecured Notes (112.21.c&d)	4,130,325,000	4,280,325,000	4,205,325,000
	10 Less: Fair Value Hedges (See Note on Ln 12 below)	-	-	_
	11 Total Average Debt	3,867,825,000	4,062,325,000	3,965,075,000
	12 NOTE: The balance of fair value hedges on outstanding lon	_	uded from the balar	ice of long term debt
	included in the formula's capital structure. (Column H of the	FF1)		
	13 Annual Interest Expense for 2012			
	14 Interest on Long Term Debt (256-257.33.i)			212,506,228
	Less: Total Hedge Gain/Expense Accumulated from p 256-257, o	col. (i) of FERC Form 1		
	included in Ln 14 and shown in Ln 29 below.	(,)		(2,097,663)
	16 Plus: Allowed Hedge Recovery From Ln 34 below.			(2,097,663)
	17 Amort of Debt Discount & Expense (117.63.c)			3,978,647
	18 Amort of Loss on Reacquired Debt (117.64.c)			1,336,128
	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)	•	217,821,003
	22 Average Cost of Debt for 2012 (Ln 21/Ln 11)		Г	5.49%
	/ 17 31 4 30 00 01 0 00 01 01 10 1 10 1 L (LII L I/LII 1 I I)		L	J. 1 3 /0

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.

					Amortization	Period
HEDGE AMOUNTS BY ISSUANCE (FROM p. 256-257 (i) of the FERC Form 1)	Total Hedge (Gain)/Loss for 2012	Less Excludable Amounts (See NOTE on Line 23)	Net Includable Hedge Amount	Remaining Unamortized Balance	Beginning	Ending
24 SUN Cash Flow Hedge - 6.000% 25 SUN Cash Flow Hedge - 5.375% 26 27 28	(418,450) (1,679,213)	-	(418,450) (1,679,213)	(1,429,705) (11,264,719)	Jun-06 Sep-09	Jun-16 Sep-19
29 Total Hedge Amortization	(2,097,663)	-				
30 Hedge Gain or Loss Prior to Application of Recovery Limit (Sum 31 Total Average Capital Structure Balance for 2012 (True-UP TCO 32 Financial Hedge Recovery Limit - Five Basis Points of Total Cap 33 Limit of Recoverable Amount 34 Recoverable Hedge Amortization (Lesser of Ln 30 or Ln 33)	S, Ln 165)		(2,097,663) 8,596,028,353 0.0005 4,298,014 (2,097,663)			
Preferred Stock			<u>Average</u>			
35 0% Series - 0 - Dividend Rate (p. 250-251. 7 & 10.a) 36 0% Series - 0 - Par Value (p. 250-251. 8.c) 37 0% Series - 0 - Shares O/S (p.250-251. 8 & 11.e)	0.00% \$ -	4.08% \$ -				
38 0% Series - 0 - Monetary Value (Ln 36 * Ln 37) 29 0% Series - 0 - Dividend Amount (Ln 35 * Ln 38)	- -	-	-			
40,00% Carias O. Dividand Data (n. 050,054 a)	0.000/	4 200/				

elopment of Cost of Preferred Stock				
Preferred Stock			<u>Average</u>	
35 0% Series - 0 - Dividend Rate (p. 250-251. 7 & 10.a)	0.00%	4.08%		
36 0% Series - 0 - Par Value (p. 250-251. 8.c)	\$ - \$	_		
37 0% Series - 0 - Shares O/S (p.250-251. 8 & 11.e)	-	-		
38 0% Series - 0 - Monetary Value (Ln 36 * Ln 37)	-	-	-	
39 0% Series - 0 - Dividend Amount (Ln 35 * Ln 38)	-	-	-	
40 0% Series - 0 - Dividend Rate (p. 250-251.a)	0.00%	4.20%		
41 0% Series - 0 - Par Value (p. 250-251.c)	\$ - \$	-		
42 0% Series - 0 - Shares O/S (p.250-251. e)	-	-		
43 0% Series - 0 - Monetary Value (Ln 41 * Ln 42)	-	-	-	
44 0% Series - 0 - Dividend Amount (Ln 40 * Ln 43)	-	-	-	
45 0% Series - 0 - Dividend Rate (p. 250-251.a)	0.00%	4.40%		
46 0% Series - 0 - Par Value (p. 250-251.c)	\$ - \$	-		
47 0% Series - 0 - Shares O/S (p.250-251.e)	-	-		
48 0% Series - 0 - Monetary Value (Ln 46 * Ln 47)	-	-	-	
49 0% Series - 0 - Dividend Amount (Ln 45 * Ln 48)	-	-	-	
50 0% Series - 0 - Dividend Rate (p. 250-251.a)	0.00%	4.50%		
51 0% Series - 0 - Par Value (p. 250-251.c)	\$ - \$	-		
52 0% Series - 0 - Shares O/S (p.250-251.e)	-	-		
53 0% Series - 0 - Monetary Value (Ln 51 * Ln 52)	-	-	-	
54 0% Series - 0 - Dividend Amount (Ln 50 * Ln 53)	-	-	-	
55 Balance of Preferred Stock (Lns 38, 43, 48, 54)	-	-	Year End Total Agrees to FF1 p.112, Ln 3, col (c) & (c	d)
56 Dividends on Preferred Stock (Lns 39, 44, 49)	-	-	-	
57 Average Cost of Preferred Stock (Ln 56/55)	0.00%	0.00%		

AEP East Companies Cost of Service Formula Rate Using 2012 FF1 Balances Worksheet N - Gains (Losses) on Sales of Plant Held For Future Use OHIO POWER COMPANY

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

	(A)	(B)	(C) Function	(D) (E)	(F)	(G) Functional	(H) Functionalized	(I) FERC
Line	Date	Property Description	(T) or (G) T = Transmission G = General	Basis Proceeds	(Gain) / Loss	Allocator	Proceeds (Gain) / Loss	Account
1					-	0.000%	-	
2					-	0.000%	-	
3					-	0.000%	-	
4			Mark	(Gain) or Loss for 2012				

AEP East Companies

Cost of Service Formula Rate Using 2012 FF1 Balances

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

Total AEP East Operating Company PBOP Settlement Amount

48,100,000

Allocation of PBOP Settlement Amount for 2012

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 2012	Actual Expense	Allowable Expense	One Year Functional Expense (Over)/Under
	(A)	(B)=(A)/Total (A)	(C)=(B) * 48100000	(D)	(E)=(A) * (D)	(F)=(C) * (D)	(G)=(E) - (F)
	(Line 14)						
1 APCo	11,359,793	27.78%	13,362,440	7.081%	804,397	946,207	(141,809)
2							
3 I&M	10,586,657	25.89%	12,453,006	4.206%	445,250	523,744	(78,494)
4 KPCo	2,188,039	5.35%	2,573,774	9.694%	212,116	249,511	(37,394)
5 KNGP	277,875	0.68%	326,862	13.137%	36,506	42,941	(6,436)
6 OPCo	16,164,303	39.53%	19,013,950	6.771%	1,094,477	1,287,425	(192,948)
7 WPCo	314,520	0.77%	369,968	7.846%	24,676	29,026	(4,350)
8 Sum of Lines 1 to 7	40,891,187	•	48,100,000		2,617,422	3,078,853	(461,432)

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

	<u>APCo</u>	<u>I&M</u>	<u>KPCo</u>	<u>KNGSPT</u>	<u>OPCo</u>	<u>WPCo</u>	AEP East Total
9 Direct Charged PBOP Expense per Actuarial Report	10,991,074	9,836,923	1,994,927	247,734	13,628,228	282,183	36,981,069
10 Additional PBOP Ledger Entries (from Company Records)	(669,581)	(45,394)	•	•	1,105,077	-	
11 Medicare Subsidy	-	-	-	-	-	-	-
12 Net Company Expense (Ln 9 + Ln 10 + Ln 11)	10,321,493	9,791,529	1,994,927	247,734	14,733,305	282,183	37,371,171
13 PBOP Expenses From AEP Service Corporation (from Company Records)	1,038,300	795,128	193,112	30,141	1,430,998	32,337	3,520,016
14 Company PBOP Expense (Ln 12 + Ln 13)	11,359,793	10,586,657	2,188,039	277,875	16,164,303	314,520	40,891,187

AEP EAST COMPANIES PJM FORMULA RATE WORKSHEET P - TRANSMISSION DEPRECIATION RATES EFFECTIVE AS OF 1/1/2012 FOR SINGLE JURISDICTION COMPANIES OHIO POWER COMPANY

352.0	2.02%
353.0	2.29%
354.0	1.88%
354.0	1.88%
355.0	3.52%
355.0	3.52%
356.0	1.91%
356.0	1.91%
356.0	1.91%
356.0	1.91%
356.0	1.91%
357.0	2.26%
358.0	3.27%
	354.0 354.0 355.0 355.0 356.0 356.0 356.0 356.0 356.0

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 Transmission Cost of Service Formula Rate Utilizing Historic Cost Data for 2012 and Projected Net Plant at Year-End 2013

WHEELING POWER COMPANY

Line No.		(f. 122)				Tr	ransmission Amount
1	REVENUE REQUIREMENT (w/o incentives)	(ln 138)	Total	۸۱۱۵	ootor		\$16,266,957
2	REVENUE CREDITS	(Note A) (Worksheet E)	1,416,286	DA	1.00000	\$	1,416,286
3	REVENUE REQUIREMENT For All Company Facilities	(In 1 less In 2)				\$	14,850,671
	The Carrying Charge Calculations on lines 6 to 11 belonies in the second second second contract the second		_				
4	Revenue Requirement for PJM Schedule 12 Facilities (v	v/o incentives) (Worksheet J)	393,660	DA	1.00000	\$	393,660
5 6 7	NET PLANT CARRYING CHARGE w/o intra-AEP charge Annual Rate Monthly Rate	es or credits or ROE incentives (Note B) ((In 1 - In 105 - In 106)/((In 48 + In 49 + In 50 (In 6 / 12)	+ ln 51 + ln 53) x 100))				19.30% 1.61%
8 9	NET PLANT CARRYING CHARGE ON LINE 6, w/o dep	reciation or ROE incentives (Note B) ((In 1 - In 105 - In 106 - In 111 - In 112) /((In 4	8 + ln 49 + ln 50 + ln 51 + ln 53)	x 100))			16.46%
10 11	NET PLANT CARRYING CHARGE ON LINE 9, w/o Retu Annual Rate	rn, income taxes or ROE incentives (Note B) ((In 1 - In 105 - In 106 - In 111 - In 112 - In 13	3 - In 134) /((In 48 + In 49 + In 50) + ln 51 + ln 53) :	x 100))		2.98%
12	ADDITIONAL REVENUE REQUIREMENT for projects w/	incentive ROE's (Note B) (Worksheet J)					-
13		REVENUE REQUIREMENT FOR SCHEE	DULE 1A CHARGES				
14 15 16	Total Load Dispatch & Scheduling (Account 561) Less: Load Dispatch - Scheduling, System Control and I Less: Load Dispatch - Reliability, Planning & Standards						106,849 5,085 0
17	Total 561 Internally Developed Costs	(Line 14 - Line 15 - Line 16)				_	101,764

(5)

(4)

AEP East Companies Transmission Cost of Service Formula Rate Utilizing Historic Cost Data for 2012 and Projected Net Plant at Year-End 2013

WHEELING POWER COMPANY

(3)

(2)

(1)

	` '	,	,	•	,	. ,
		Data Sources				Total
Line	RATE BASE CALCULATION	(See "General Notes")	<u>TO Total</u> NOTE <u>C</u>	Alloc	ator_	<u>Transmission</u>
No.	GROSS PLANT IN SERVICE		NOTE C			
18	Production	(Worksheet A In 1.C)	0	NA	0.00000	0
19	Less: Production ARO (Enter Negative)	(Worksheet A In 2.C)	0	NA	0.00000	0
20	Transmission	(Worksheet A In 3.E & Ln 142)	88,587,641	DA	4 00000	88,587,641
21 22	Less: Transmission ARO (Enter Negative)	(Worksheet A In 4.E & Ln 143)	0 18,317,776	TP	1.00000 1.00000	10 247 776
23	Plus: Transmission Plant-in-Service Additions (World Plus: Additional Trans Plant on Transferred Assets)		10,317,776	DA DA	1.00000	18,317,776
24	Distribution	(Worksheet A In 5.C)	132,072,558	NA	0.00000	0
25	Less: Distribution ARO (Enter Negative)	(Worksheet A In 6.C)	0	NA	0.00000	0
26	General Plant	(Worksheet A In 7.C)	5,034,700	W/S	0.07846	395,000
27	Less: General Plant ARO (Enter Negative)	(Worksheet A In 8.C)	-34,819	W/S	0.07846	(2,732)
28	Intangible Plant	(Worksheet A In 9.C)	982,428	W/S	0.07846	77,077
29	TOTAL GROSS PLANT	(sum lns 18 to 28)	244,960,284			107,374,762
30	ACCUMULATED DEPRECIATION AND AMORTIZATION	ON				
31	Production	(Worksheet A In 12.C)	0	NA	0.00000	0
32	Less: Production ARO (Enter Negative)	(Worksheet A In 13.C)	0	NA	0.00000	0
33	Transmission	(Worksheet A In 14.C & 28.C)	20,227,192	TP1=	1.00000	20,227,192
34	Less: Transmission ARO (Enter Negative)	(Worksheet A In 15.C)	0	TP1=	1.00000	0
35	Plus: Transmission Plant-in-Service Additions (World		421,551	DA	1.00000	421,551
36 37	Plus: Additional Projected Deprec on Transferred As Plus: Additional Transmission Depreciation for 2013		1,970,536	DA TP1	1.00000 1.00000	1,970,536
38	Plus: Additional General & Intangible Depreciation for	· ·	204,920	W/S	0.07846	16,077
39	Plus: Additional Accum Deprec on Transferred Asse	· · · · · · · · · · · · · · · · · · ·	0	DA	1.00000	0
40	Distribution	(Worksheet A In 16.C)	41,591,445	NA	0.00000	0
41	Less: Distribution ARO (Enter Negative)	(Worksheet A In 17.C)	0	NA	0.00000	0
42	General Plant	(Worksheet A In 18.C)	2,531,284	W/S	0.07846	198,593
43 44	Less: General Plant ARO (Enter Negative) Intangible Plant	(Worksheet A In 19.C) (Worksheet A In 20.C)	-18,391 742,028	W/S W/S	0.07846 0.07846	(1,443) 58,216
45	TOTAL ACCUMULATED DEPRECIATION	(sum lns 31 to 44)	67,670,565	VV/S	0.07040	22,890,723
10	TO THE MODERNIED BET REGIMENT	(can inc or to 11)	01,010,000			22,000,120
46	NET PLANT IN SERVICE					
47	Production	(ln 18 + ln 19 - ln 31 - ln 32)	0			0
48 49	Transmission Plus: Transmission Plant-in-Service Additions (In 22)	(ln 20 + ln 21 - ln 33 - ln 34)	68,360,449 17,806,335			68,360,449
50	Plus: Additional Trans Plant on Transferred Assets	•	17,896,225 0			17,896,225 0
51	Plus: Additional Transmission Depreciation for 2013		(1,970,536)			(1,970,536)
52	Plus: Additional General & Intangible Depreciation for	· · · · · · · · · · · · · · · · · · ·	(204,920)			(16,077)
53	Plus: Additional Accum Deprec on Transferred Asse	, , ,	0			0
54	Distribution	(ln 24 + ln 25 - ln 40 - ln 41)	90,481,113			0
55 56	General Plant Intangible Plant	(In 26 + In 27 - In 42 - In 43) (In 28 - In 44)	2,486,988 240,400			195,118 18,861
50 57	TOTAL NET PLANT IN SERVICE	(sum lns 47 to 56)	177,289,719			84,484,039
0.		(00 10 00)	,,			0 1, 10 1,000
58	DEFERRED TAX ADJUSTMENTS TO RATE BASE	(Note D)	0	NIA		0
59 60	Account No. 281.1 (enter negative) Account No. 282.1 (enter negative)	(Worksheet B, In 2 & In 5.C) (Worksheet B, In 7 & In 10.C)	(29,722,622)	NA DA		(14,921,144)
61	Account No. 283.1 (enter negative)	(Worksheet B, In 12 & In 15.C)	(3,862,468)	DA		(321,239)
62	Account No. 190.1	(Worksheet B, In 17 & In 20.C)	2,710,890	DA		255,759
63	Account No. 255 (enter negative)	(Worksheet B, In 24 & In 25.C)	(27,057)	DA		(8,892)
64	TOTAL ADJUSTMENTS	(sum Ins 59 to 63)	(30,901,257)			(14,995,516)
65	PLANT HELD FOR FUTURE USE	(Worksheet A In 29.C & In 30.C)	_	DA		0
		,				· ·
66	REGULATORY ASSETS	(Worksheet A In 36. (C))	0	DA		0
67	WORKING CAPITAL	(Note E)				
68	Cash Working Capital	(1/8 * In 88)	156,943			156,943
69 70	Transmission Materials & Supplies	(Worksheet C, In 2.(D))	1,614	TP	1.00000	1,614
70 71	A&G Materials & Supplies Stores Expense	(Worksheet C, In 3.(D)) (Worksheet C, In 4.(D))	1,519 0	W/S GP(h)	0.07846 0.39294	119 0
7 1 72	Prepayments (Account 165) - Labor Allocated	(Worksheet C, In 4.(D))	8,047,475	W/S	0.07846	631,369
73	Prepayments (Account 165) - Gross Plant	(Worksheet C, In 6.F)	152,876	GP(h)	0.39294	60,071
74	Prepayments (Account 165) - Transmission Only	(Worksheet C, In 6.E)	0	DA	1.00000	0
75 70	Prepayments (Account 165) - Unallocable	(Worksheet C, In 6.D)	(7,804,737)	NA	0.00000	0
76	TOTAL WORKING CAPITAL	(sum lns 68 to 75)	555,690			850,116
77	IPP CONTRIBUTIONS FOR CONSTRUCTION	(Note F) (Worksheet D, In 7.B)	-	DA	1.00000	-
	DATE DAGE /	·	440.044.1=0			70.000.000
78	RATE BASE (sum lns 57, 64, 65, 66, 76, 77)		<u>146,944,152</u>			70,338,640

AEP East Companies Transmission Cost of Service Formula Rate Utilizing Historic Cost Data for 2012 and Projected Net Plant at Year-End 2013

WHEELING POWER COMPANY

(1) (2) (3) (4) (5)

	EXPENSE, TAXES, RETURN & REVENUE REQUIREMENTS CALCULATION	Data Sources (See "General Notes")	<u>TO Total</u>	Allo	ocator_	Total <u>Transmission</u>
Line No.	OPERATION & MAINTENANCE EXPENSE					
79	Production	321.80.b	101,565,867			
80	Distribution	322.156.b	5,330,356			
81	Customer Related Expense	322.164,171,178.b	3,018,334			
82	Regional Marketing Expenses	322.131.b	, , , <u>-</u>			
83	Transmission	321.112.b	1,362,394			
84	TOTAL O&M EXPENSES	(sum lns 79 to 83)	111,276,951			
85	Less: Total Account 561	(Note G) (Worksheet F, In 14.C)	106,849			
86	Less: Account 565	(Note H) 321.96.b	-			
87	Less: State Regulatory Deferrals & Amortizations	(Note I) (Worksheet F, In 4.C)	-	TD	4 00000	4.055.545
88	Total O&M Allocable to Transmission	(Ins 83 - 85 - 86 - 87)	1,255,545	TP	1.00000	1,255,545
89	Administrative and General	323.197.b (Note J)	2,731,308			
90	Less: Acct. 924, Property Insurance	323.185.b	208,083			
91	Acct. 9260039 PBOP Expense	PBOP Worksheet O Line 9 & 10, (Note K)	282,183			
92	Acct. 9260057 PBOP Medicare Subsidy	PBOP Worksheet O Line 11, (Note K)	-			
93	PBOP Expense Billed From AEPSC	PBOP Worksheet O Line 13, (Note K)	32,337			
94	Acct. 928, Reg. Com. Exp.	323.189.b	-			
95	Acct. 930.1, Gen. Advert. Exp.	323.191.b	2,937			
96	Acct. 930.2, Misc. Gen. Exp.	323.192.b	77,627			
97	Balance of A & G	(ln 89 - sum ln 90 to ln 96)	2,128,141	W/S	0.07846	166,964
98	Plus: Acct. 924, Property Insurance	(ln 90)	208,083	GP(h)	0.39294	81,764
99 100	Acct. 928 - Transmission Specific	Worksheet F In 18.(E) (Note L)	-	TP TP	1.00000	-
100 101	Acct 930.1 - Only safety related ads -Direct Acct 930.2 - Misc Gen. Exp Trans	Worksheet F In 29.(E) (Note L) Worksheet F In 35.(E) (Note L)	632	DA	1.00000 1.00000	632
101	Settlement Approved PBOP Recovery	PBOP Worksheet O, Col. C, Line 7, (Note M)	369,968	W/S	0.07846	29,026
103	A & G Subtotal	(sum lns 97 to 102)	2,706,824	**/**	0.07040	278,387
100	/ CC Captolal	(6411 1110 67 10 102)	2,7 00,02 1			270,007
104	O & M EXPENSE SUBTOTAL	(ln 88 + ln 103)	3,962,369			1,533,932
105	Plus: TEA Settlement in Account 565	Company Records (Note H)	-	DA	1.00000	-
106	Plus: Transmission Lease Payments To Affiliates in Ac	cct 565 (Company Records) (Note H)	<u>-</u>	DA	1.00000	
107	TOTAL O & M EXPENSE	(ln 104 + ln 105 + ln 106)	3,962,369			1,533,932
108	DEPRECIATION AND AMORTIZATION EXPENSE					
109	Production	336.2-6.f	-	NA	0.00000	-
110 111	Distribution	336.8.f 336.7.f	4,242,661	NA TD1	0.00000 1.00000	- 1 070 526
112	Transmission Plus: Transmission Plant-in-Service Additions (Worksl		1,970,536 421,551	TP1 DA	1.00000	1,970,536 421,551
113	General	336.10.f	157,755	W/S	0.07846	12,377
114	Intangible	336.1.f	47,165	W/S	0.07846	3,700
115	TOTAL DEPRECIATION AND AMORTIZATION	(Lns 109+110+111	6,839,668			2,408,164
		+112+113+114)	, ,			, ,
116	TAXES OTHER THAN INCOME	(Note N)				
117	Labor Related					
118	Payroll	Worksheet H In 21.(D)	177,131	W/S	0.07846	13,897
119	Plant Related	W	4.700.440	D .4		740.004
120	Property Cross Respirety/Salas & Llas	Worksheet H In 21.(C) & In 35.(C)	1,726,413	DA	0.00000	742,994
121 122	Gross Receipts/Sales & Use Other	Worksheet H In 21.(F) Worksheet H In 21.(E)	5,520,256 527,793	NA GP(h)	0.00000 0.39294	- 207,391
123	TOTAL OTHER TAXES	(sum lns 118 to 122)	7,951,593	OI (II)	0.39294	964,282
120	TOTAL OTTIER TAXES	(30111113 1 10 to 122)	7,331,333			304,202
124	INCOME TAXES	(Note O)				
125	T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =	()	40.03%			
126	EIT=(T/(1-T)) * (1-(WCLTD/WACC)) =		59.28%			
127	where WCLTD=(In 162) and WACC = (In 165)					
128	and FIT, SIT & p are as given in Note O.					
129	GRCF=1 / (1 - T) = (from ln 125)		1.6675			
130	Amortized Investment Tax Credit (enter negative)	(FF1 p.114, ln 19.c)	-			
121	Income Tax Calculation	(ln 107 * ln 105)	0 022 720			4 220 015
131 132	ITC adjustment	(In 127 * In 135) (In 129 * In 130)	8,832,728	NP(h)	0.42443	4,228,015
133	TOTAL INCOME TAXES	(sum lns 131 to 132)	8,832,728	141 (11)	0.42443	4,228,015
100	TOTAL INCOME TAXES	(34111113 131 13 132)	0,002,720			7,220,010
134	RETURN ON RATE BASE (Rate Base * WACC)	(ln 78 * ln 165)	14,900,610			7,132,565
	,	,	, ,			, ,
135	INTEREST ON IPP CONTRIBUTION FOR CONST. (Note	e F) (Worksheet D, In 2.(B))	-	DA	1.00000	-
	(0.1.)					
136	(Gains) / Losses on Sales of Plant Held for Future Use (V	Vorksheet N, In 4, Cols. ((F) & (H))	-			-
107	Tay Impact on (Caina) / Language Calago (Discould 1) (or Future Hee /le 400 * le 400\				
137	Tax Impact on (Gains) / Losses on Sales of Plant Held for	or Future Use (In 136 " In126)	-			-
138	TOTAL REVENUE REQUIREMENT	-	42,486,968			16,266,957
100	(sum lns 107, 115, 123, 133, 134, 135, 136, 137)	-	74,700,000			10,200,301
	(34.11.11.0 107, 110, 120, 100, 107, 100, 100, 107)					

AEP East Companies Transmission Cost of Service Formula Rate Utilizing Historic Cost Data for 2012 and Projected Net Plant at Year-End 2013

WHEELING POWER COMPANY

SUPPORTING CALCULATIONS

ln								
No.	TRANSMISSION PLANT INCLUDED IN PJM TARIFF							
139	Total transmission plant	(In 20)						88,587,641
140	Less transmission plant excluded from PJM Tariff (Note	e P)						-
141	Less transmission plant included in OATT Ancillary Serv	vices (Worksheet A, In 23, Col. (C)) (Note Q)					-
142	Transmission plant included in PJM Tariff	(In 139 - In 140 - In 141)					_	88,587,641
143	Percent of transmission plant in PJM Tariff	(In 142 / In 139)					TP	1.00000
				Payroll Billed from				
144	WAGES & SALARY ALLOCATOR (W/S)	(Note R)	Direct Payroll	AEP Service Corp.	Total			
145	Production	354.20.b	0	0	-	NA	0.00000	-
146	Transmission	354.21.b	1,068	204,657	205,725	TP	1.00000	205,725
147	Regional Market Expenses	354.22.b	0	0	-	NA	0.00000	-
148	Distribution	354.23.b	1,433,488	326,446	1,759,934	NA	0.00000	-
149	Other (Excludes A&G)	354.24,25,26.b	356,057	300,471	656,528	NA	0.00000	<u>-</u>
150	Total	(sum lns 145 to 149)	1,790,613	831,574	2,622,187			205,725
151	Transmission related amount						W/S=	0.07846
							W/S=	
152	WEIGHTED AVERAGE COST OF CAPITAL (WACC)	(Workshoot L. In 35 col. (D))					W/S= 	\$
152 153	WEIGHTED AVERAGE COST OF CAPITAL (WACC) Long Term Interest	(Worksheet L, In. 35, col. (D))					W/S= 	
152 153 154	WEIGHTED AVERAGE COST OF CAPITAL (WACC) Long Term Interest Preferred Dividends	(Worksheet L, In. 35, col. (D)) (Worksheet L, In. 40, col. (D))					W/S= 	\$
152 153 154 155	WEIGHTED AVERAGE COST OF CAPITAL (WACC) Long Term Interest Preferred Dividends Development of Common Stock:	(Worksheet L, In. 40, col. (D))					W/S= 	\$ 1,312,500 -
152 153 154 155 156	WEIGHTED AVERAGE COST OF CAPITAL (WACC) Long Term Interest Preferred Dividends Development of Common Stock: Proprietary Capital	(Worksheet L, In. 40, col. (D)) (FF1 p 112, Ln 16.c)					W/S= 	\$
152 153 154 155 156 157	WEIGHTED AVERAGE COST OF CAPITAL (WACC) Long Term Interest Preferred Dividends Development of Common Stock: Proprietary Capital Less: Preferred Stock	(Worksheet L, In. 40, col. (D)) (FF1 p 112, Ln 16.c) (FF1 p 112, Ln 3.c)					W/S= 	\$ 1,312,500 -
152 153 154 155 156 157 158	WEIGHTED AVERAGE COST OF CAPITAL (WACC) Long Term Interest Preferred Dividends Development of Common Stock: Proprietary Capital Less: Preferred Stock Less: Account 216.1	(Worksheet L, In. 40, col. (D)) (FF1 p 112, Ln 16.c) (FF1 p 112, Ln 3.c) (FF1 p 112, Ln 12.c)					W/S= 	\$ 1,312,500 - 90,109,311 - -
152 153 154 155 156 157 158 159	WEIGHTED AVERAGE COST OF CAPITAL (WACC) Long Term Interest Preferred Dividends Development of Common Stock: Proprietary Capital Less: Preferred Stock Less: Account 216.1 Less: Account 219	(Worksheet L, In. 40, col. (D)) (FF1 p 112, Ln 16.c) (FF1 p 112, Ln 3.c) (FF1 p 112, Ln 12.c) (FF1 p 112, Ln 15.c)	9)				W/S= 	\$ 1,312,500 - 90,109,311 - - (473,816)
152 153 154 155 156 157 158	WEIGHTED AVERAGE COST OF CAPITAL (WACC) Long Term Interest Preferred Dividends Development of Common Stock: Proprietary Capital Less: Preferred Stock Less: Account 216.1	(Worksheet L, In. 40, col. (D)) (FF1 p 112, Ln 16.c) (FF1 p 112, Ln 3.c) (FF1 p 112, Ln 12.c)	9)					\$ 1,312,500 - 90,109,311 - -
152 153 154 155 156 157 158 159 160	WEIGHTED AVERAGE COST OF CAPITAL (WACC) Long Term Interest Preferred Dividends Development of Common Stock: Proprietary Capital Less: Preferred Stock Less: Account 216.1 Less: Account 219	(Worksheet L, In. 40, col. (D)) (FF1 p 112, Ln 16.c) (FF1 p 112, Ln 3.c) (FF1 p 112, Ln 12.c) (FF1 p 112, Ln 15.c)	9)	\$	%		Cost	\$ 1,312,500 - 90,109,311 - (473,816) 90,583,127
152 153 154 155 156 157 158 159 160	WEIGHTED AVERAGE COST OF CAPITAL (WACC) Long Term Interest Preferred Dividends Development of Common Stock: Proprietary Capital Less: Preferred Stock Less: Account 216.1 Less: Account 219 Common Stock	(Worksheet L, In. 40, col. (D)) (FF1 p 112, Ln 16.c) (FF1 p 112, Ln 3.c) (FF1 p 112, Ln 12.c) (FF1 p 112, Ln 15.c)	9)	\$ 25,000,000	% 21.63%		Cost (Note S)	\$ 1,312,500 - 90,109,311 - (473,816) 90,583,127 Weighted
152 153 154 155 156 157 158 159 160	WEIGHTED AVERAGE COST OF CAPITAL (WACC) Long Term Interest Preferred Dividends <u>Development of Common Stock:</u> Proprietary Capital Less: Preferred Stock Less: Account 216.1 Less: Account 219 Common Stock Long Term Debt (Note T) Worksheet L, In 35, col. (B))	(Worksheet L, In. 40, col. (D)) (FF1 p 112, Ln 16.c) (FF1 p 112, Ln 3.c) (FF1 p 112, Ln 12.c) (FF1 p 112, Ln 15.c)	9)	\$ 25,000,000	21.63%		Cost	\$ 1,312,500 - 90,109,311 - (473,816) 90,583,127 Weighted 0.0114
152 153 154 155 156 157 158 159 160 161 162 163	WEIGHTED AVERAGE COST OF CAPITAL (WACC) Long Term Interest Preferred Dividends Development of Common Stock: Proprietary Capital Less: Preferred Stock Less: Account 216.1 Less: Account 219 Common Stock Long Term Debt (Note T) Worksheet L, In 35, col. (B)) Preferred Stock (In 157)	(Worksheet L, In. 40, col. (D)) (FF1 p 112, Ln 16.c) (FF1 p 112, Ln 3.c) (FF1 p 112, Ln 12.c) (FF1 p 112, Ln 15.c)	9)	25,000,000	21.63% 0.00%	•	Cost (Note S) 0.0525	\$ 1,312,500 - 90,109,311 - (473,816) 90,583,127 Weighted 0.0114 0.0000
152 153 154 155 156 157 158 159 160	WEIGHTED AVERAGE COST OF CAPITAL (WACC) Long Term Interest Preferred Dividends <u>Development of Common Stock:</u> Proprietary Capital Less: Preferred Stock Less: Account 216.1 Less: Account 219 Common Stock Long Term Debt (Note T) Worksheet L, In 35, col. (B))	(Worksheet L, In. 40, col. (D)) (FF1 p 112, Ln 16.c) (FF1 p 112, Ln 3.c) (FF1 p 112, Ln 12.c) (FF1 p 112, Ln 15.c)	9)	•	21.63%		Cost (Note S)	\$ 1,312,500 - 90,109,311 - (473,816) 90,583,127 Weighted 0.0114

AEP East Companies

Transmission Cost of Service Formula Rate
Utilizing Historic Cost Data for 2012 and Projected Net Plant at Year-End 2013

WHEELING POWER COMPANY

<u>Letter</u> <u>Notes</u>

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

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

See Worksheet E for details.

- B The annual and monthly net plant carrying charges on page 1 are used to compute the revenue requirement for RTEP sponsored upgrades or those projects receiving approved incentive-ROE's.
- C Transmission Plant balances in this study are projected as of December 31, 2013. Other ratebase amounts are as of December 31, 2012.
- The total-company balances shown for Accounts 281, 282, 283, 190 only reflect ADIT that relates to utility operations. The balance of Account 255 is reduced by prior flow throughs and is completely excluded if the utility chose to utilize amortization of tax credits against FIT expense. An exception to this is pre-1971 ITC balances, which are required to be taken as an offset to rate base. Account 281 is not allocated. In compliance with FERC Rulemaking RM02-7-000, Asset Retirement Obligation deferrals have been removed from ratebase. Transmission ADIT allocations are shown on WS B.

The company will not include the ADIT portion of deferred hedge gains and losses in rate base.

- E Cash Working Capital assigned to transmission is one-eighth of O&M allocated to transmission, as shown on line 88. It excludes:
 - 1) Load Scheduling & Dispatch Charges in account 561 that are collected in the OATT Ancilliary Services Revenue, as shown on line 85.
 - 2) AEP transmission equalization transfers, as shown on line 86
 - 3) The impact of state regulatory deferrals and amortizations, as shown on line 87
 - 4) All A&G Expenses, as shown on line 103.
- F Consistent with Paragraph 657 of Order 2003-A, the amount on line 77 is equal to the balance of IPP System Upgrade Credits owed to transmission customers that made contributions toward the construction of System upgrades, and includes accrued interest and unreturned balance of contributions. The annual interest expense is included on line 135.
- Removes from the cost of service the Load Scheduling and Dispatch expenses booked to accounts 561.1 through 561.8. Expenses recorded in these accounts, with the exception of 561.4 & 561.8 (lines 15 & 16 above) are recovered in Schedule 1A, OATT ancillary services rates. See Worksheet F, lines 5 through 14, for descriptions and the Form 1 Source of these accounts' balances.
- Removes cost of transmission service provided by others to determine the basis of cash working capital on line 88. To the extent such service is incurred to provide the PJM service at issue, e.g. transmission equalization agreement, such costs are added back on lines 105 and 106 to determine the total O&M collected in the formula. The amounts on lines 105 and 106 are also excluded in the calculation of the FCR percentage calculated on lines 5 through 11. The addbacks on lines 105 and 106 of activity recorded in 565 represents inter-company sales or purchases of transmission capacity necessary to meet each AEP company's transmission load relative to their available transmission capacity.

The company records referenced on lines 105 and 106 is the WHEELING POWER COMPANY general ledger.

- I Removes the impact of state regulatory deferrals or their amortization from O&M expense.
- General Plant and Administrative & General expenses, other than in accounts 924, 928, and 930, will be functionalized based on the Wages & Salaries "W/S" allocator. The allocation basis for accounts 924, 928 and 930 are separately presented in the formula. A change in the allocation method for an account must be approved via a 205 filing with the FERC.
- K These deductions on lines 91 through 93 are to remove from the cost of service the expenses recorded by the company for Postemployment Benefits Other than Pensions (PBOP). See Note M below for the recoverable PBOP expense.
- Expenses reported for these A&G accounts will be included in the cost of service only to the extent they are directly assignable to transmission service. Worksheet F allocates these expense items. Acct 928 Includes Regulatory Commission expenses itemized in FERC Form-1 at page 351, column H. FERC Assessment Fees and Annual Charges shall not be allocated to transmission. Only safety-related and educational advertising costs in Account 930.1 are included in the TCOS. Account 930.2 includes the expenses incurred by the transmission function for Associated Business Development revenues given as a credit to the TCOS on Worksheet E.
- M See note K above. Per the settlement in Docket ER08-1329, recoverable PBOP expense is based on an annual total for the operating companies that is ratioed to them based on the total of actual annual PBOP costs, including charges from the AEP Service Corportation. The calculation of the recoverable amount for each company is shown on Worksheet O, and the process for updating the annual total is documented on Attachment F, Allowable PBOP Expense Formula.
- N Includes only FICA, unemployment, highway, property and other assessments charged in the current year. Gross receipts, sales & use and taxes related to income are excluded.
- The currently effective income tax rate, where FIT is the Federal income tax rate; SIT is the State income tax rate, and p = the percentage of federal income tax deductible for state income taxes. See Worksheet G for the development of the Company's composite SIT. A utility that elected to utilize amortization of tax credits against taxable income, rather than book tax credits to Account No. 255 and reduce rate base, must reduce its income tax expense by the amount of the Amortized Investment Tax Credit (Form 1, 266.8.f) (In 130) multiplied by (1/1-T). If the applicable tax rates are zero enter 0.

Inputs Required: FIT = 35.00%

SIT= 7.74% (State Income Tax Rate or Composite SIT. Worksheet G))

p = 0.00% (percent of federal income tax deductible for state purposes)

- P Removes plant excluded from the OATT because it does not meet the PJM's definition of Transmission Facilities or is otherwise ineligible to be recovered under the OATT.
- Q Removes transmission plant (e.g. step-up transformers) included in the development of OATT ancillary service rates and not already removed for reasons indicated in Note P.
- R Includes functional wages & salaries billed by AEP Service Corporation for support of the operating company.
- Long Term Debt cost rate = long-term interest (ln 153) / long term debt (ln 162). Preferred Stock cost rate = preferred dividends (ln 154) / preferred outstanding (ln 163). Common Stock cost rate (ROE) = 11.49%, the rate accepted by FERC in Docket No. ER08-1329. It includes an additional 50 basis points for PJM RTO membership. In the Projected & Historic templates, the interest expense on long-term debt is the sum of a full year's interest expense at the coupon rate for each issuance outstanding as of December 31 of the historic year. The projected expense for variable rate debt will be based on the effective rate at December 31. These conventions ensure that the expense used in the projection will reflect a full year, similar to the actual expense that will appear in the subsequent true-up of the projection, and minimize the impact on the true-up of using a partial year interest expense. The projection will reflect the actual historic-year expense recorded for issuance expenses, discounts and premiums, and gains or losses on reacquired debt. Eligible hedging gains or losses will be limited to five basis points of the projected capital structure. Details and calculations are shown on Worksheet L.
- This note only applies to Indiana Michigan Power Company.
- U This note only applies to the true-up template.

WHEELING POWER COMPANY

Line No.						Tr	ansmission Amount			
166	REVENUE REQUIREMENT (w/o incentives)	(In 303)	Total	Allor	cator	-	\$13,275,803			
167	REVENUE CREDITS	(Note A) (Worksheet E)	1,416,286	DA	1.00000	\$	1,416,286			
168	REVENUE REQUIREMENT For All Company Facilities	(In 166 less In 167)				\$	11,859,517			
	MEMO: The Carrying Charge Calculations on lines 171 to 176 below are used in calculating project revenue requirements billed through PJM Schedule 12, Transmission Enhancement Charges. The total non-incentive revenue requirements for these projects shown on line 169 is included in the total on line 168.									
169	Not applicable on this template									
170 171 172	NET PLANT CARRYING CHARGE w/o intra-AEP charge Annual Rate Monthly Rate	s or credits or ROE incentives (Note B) ((In 166 - In 270 - In 271)/ In 213 x 100) (In 171 / 12)					19.42% 1.62%			
173 174	NET PLANT CARRYING CHARGE ON LINE 171 , w/o de Annual Rate	epreciation or ROE incentives (Note B) ((In 166 - In 270 - In 271 - In 276) / In 213 x 1	00)				16.54%			
175 176	NET PLANT CARRYING CHARGE ON LINE 174, w/o ReAnnual Rate	eturn, income taxes or ROE incentives (Note B) ((In 166 - In 270 - In 271 - In 276 - In 298 - In	299) / In 213 x 100)				3.68%			
177	Not applicable on this template									
178		REVENUE REQUIREMENT FOR	R SCHEDULE 1A CHARGES							
179 180 181	Total Load Dispatch & Scheduling (Account 561) Less: Load Dispatch - Scheduling, System Control and Description Less: Load Dispatch - Reliability, Planning & Standards I						106,849 5,085 -			
182	Total 561 Internally Developed Costs	(Line 179 - Line 180 - Line 181)					101,764			

WHEELING POWER COMPANY

(1) (2) (3)

		Data Sources				Total
Line	RATE BASE CALCULATION	(See "General Notes")	<u>TO Total</u> NOTE C	Allo	<u>cator</u>	Transmission
No.	GROSS PLANT IN SERVICE		<u></u>			
183	Production	(Worksheet A In 1.C)	-	NA	0.00000	-
184	Less: Production ARO (Enter Negative)	(Worksheet A In 2.C)	-	NA	0.00000	-
185	Transmission	(Worksheet A In 3.E & Ln 307)	88,587,641	DA		88,587,641
186	Less: Transmission ARO (Enter Negative)	(Worksheet A In 4.E & Ln 308)		TP	1.00000	
187	Plus: Transmission Plant-in-Service Additions (Wo	orksheet I)	N/A	NA	0.00000	N/A
188	Plus: Additional Trans Plant on Transferred Assets	s (Worksheet I)	N/A	NA	0.00000	N/A
189	Distribution	(Worksheet A In 5.C)	132,072,558	NA	0.00000	-
190	Less: Distribution ARO (Enter Negative)	(Worksheet A In 6.C)	-	NA	0.00000	-
191	General Plant	(Worksheet A In 7.C)	5,034,700	W/S	0.07846	395,000
192	Less: General Plant ARO (Enter Negative)	(Worksheet A In 8.C)	(34,819)	W/S	0.07846	(2,732)
193	Intangible Plant	(Worksheet A In 9.C)	982,428	W/S	0.07846	77,077
194	TOTAL GROSS PLANT	(sum Ins 183 to 193)	226,642,508	GP(h)= GTD=	0.392940 0.40147	89,056,986
195	ACCUMULATED DEPRECIATION AND AMORTIZAT	ION				
196	Production	(Worksheet A In 12.C)	-	NA	0.00000	-
197	Less: Production ARO (Enter Negative)	(Worksheet A In 13.C)	-	NA	0.00000	-
198	Transmission	(Worksheet A In 14.C & 28.C)	20,227,192	TP1=	1.00000	20,227,192
199	Less: Transmission ARO (Enter Negative)	(Worksheet A In 15.C)	-	TP1=	1.00000	-
200	Plus: Transmission Plant-in-Service Additions (Wo	orksheet I)	N/A	DA	1.00000	N/A
201	Plus: Additional Projected Deprec on Transferred	Assets (Worksheet I)	N/A	DA	1.00000	N/A
202	Plus: Additional Transmission Depreciation for 20	13 (ln 276)	N/A	TP1	1.00000	N/A
203	Plus: Additional General & Intangible Depreciation		N/A	W/S	0.07846	N/A
204	Plus: Additional Accum Deprec on Transferred As	·	N/A	DA	1.00000	N/A
205	Distribution	(Worksheet A In 16.C)	41,591,445	NA	0.00000	
206	Less: Distribution ARO (Enter Negative)	(Worksheet A In 17.C)	-	NA	0.00000	-
207	General Plant	(Worksheet A In 18.C)	2,531,284	W/S	0.07846	198,593
208	Less: General Plant ARO (Enter Negative)	(Worksheet A In 19.C)	(18,391)	W/S	0.07846	(1,443)
209	Intangible Plant	(Worksheet A In 20.C)	742,028	W/S	0.07846	58,216
210	TOTAL ACCUMULATED DEPRECIATION	(sum Ins 196 to 209)	65,073,558			20,482,558
211	NET PLANT IN SERVICE					
212	Production	(ln 183 + ln 184 - ln 196 - ln 197)	-			-
213	Transmission	(ln 185 + ln 186 - ln 198 - ln 199)	68,360,449			68,360,449
214	Plus: Transmission Plant-in-Service Additions (In	187 - In 200)	N/A			N/A
215	Plus: Additional Trans Plant on Transferred Assets	s (ln 188 - ln 201)	N/A			N/A
216	Plus: Additional Transmission Depreciation for 201	13 (-ln 202)	N/A			N/A
217	Plus: Additional General & Intangible Depreciation	for 2013 (-In 203)	N/A			N/A
218	Plus: Additional Accum Deprec on Transferred As	sets (Worksheet I) (-In 204)	N/A			N/A
219	Distribution	(In 189 + In 190 - In 205 - In 206)	90,481,113			-
220	General Plant	(In 191 + In 192 - In 207 - In 208)	2,486,988			195,118
221	Intangible Plant	(In 193 - In 209)	240,400			18,861
222	TOTAL NET PLANT IN SERVICE	(sum Ins 212 to 221)	161,568,950	NP(h)=	0.424428	68,574,428
223	DEFERRED TAX ADJUSTMENTS TO RATE BASE	(Note D)		A I A		
224	Account No. 281.1 (enter negative)	(Worksheet B, In 2 & In 5.C)	-	NA		-
225	Account No. 282.1 (enter negative)	(Worksheet B, In 7 & In 10.C)	(29,722,622)	DA		(14,921,144)
226	Account No. 283.1 (enter negative)	(Worksheet B, In 12 & In 15.C)	(3,862,468)	DA		(321,239)
227	Account No. 190.1	(Worksheet B, In 17 & In 20.C)	2,710,890	DA		255,759
228 229	Account No. 255 (enter negative) TOTAL ADJUSTMENTS	(Worksheet B, In 24 & In 25.C) (sum Ins 224 to 228)	(27,057) (30,901,257)	DA		(8,892) (14,995,516)
229	TOTAL ADJUSTIVIENTS	(Suiti iiis 224 to 220)	(30,901,237)			(14,995,510)
230	PLANT HELD FOR FUTURE USE	(Worksheet A In 29.C & In 30.C)	-	DA		-
231	REGULATORY ASSETS	(Worksheet A In 36. (C))	-	DA		-
232	WORKING CAPITAL	(Note E)				
233	Cash Working Capital	(1/8 * ln 253)	156,943			156,943
234	Transmission Materials & Supplies	(Worksheet C, In 2.(D))	1,614	TP	1.00000	1,614
235	A&G Materials & Supplies	(Worksheet C, In 3.(D))	1,519	W/S	0.07846	119
236	Stores Expense	(Worksheet C, In 4.(D))	-	GP(h)	0.39294	-
237	Prepayments (Account 165) - Labor Allocated	(Worksheet D, In 6.G)	8,047,475	W/S	0.07846	631,369
238	Prepayments (Account 165) - Gross Plant	(Worksheet D, In 6.F)	152,876	GP(h)	0.39294	60,071
239	Prepayments (Account 165) - Transmission Only	(Worksheet D, In 6.E)	-	DA	1.00000	-
240	Prepayments (Account 165) - Unallocable	(Worksheet D, In 6.D)	(7,804,737)	NA	0.00000	
241	TOTAL WORKING CAPITAL	(sum Ins 233 to 240)	555,690			850,116
242	IPP CONTRIBUTIONS FOR CONSTRUCTION	(Note F) (Worksheet D, In 7.B)	-	DA	1.00000	-
243	RATE BASE (sum Ins 222, 229, 230, 231, 241, 242)		131,223,383			54,429,028
270			101,220,000			UT,TZU,UZU

WHEELING POWER COMPANY

(1) (2) (3)

	(.,	(-)	(0)	(/	(0)
	EXPENSE, TAXES, RETURN & REVENUE REQUIREMENTS CALCULATION	Data Sources (See "General Notes")	TO Total	Allo	<u>cator</u>	Total <u>Transmission</u>
Line						
No.	OPERATION & MAINTENANCE EXPENSE					
244	Production	321.80.b	101,565,867			
245	Distribution	322.156.b	5,330,356			
246	Customer Related Expense	322 & 323.164,171,178.b	3,018,334			
247	Regional Marketing Expenses	322.131.b	- ·			
248	Transmission	321.112.b	1,362,394			
249	TOTAL O&M EXPENSES	(sum Ins 244 to 248)	111,276,951			
250	Less: Total Account 561	(Note G) (Worksheet F, In 14.C)	106,849			
251	Less: Account 565	(Note H) 321.96.b	-			
252	Less: Regulatory Deferrals & Amortizations	(Note I) (Worksheet F, In 4.C)	-			
253	Total O&M Allocable to Transmission	(Ins 248 - 250 - 251 - 252)	1,255,545	TP	1.00000	1,255,545
254	Administrative and General	323.197.b (Note J)	2,731,308			
255	Less: Acct. 924, Property Insurance	323.185.b `	208,083			
256	Acct. 9260039 PBOP Expense	PBOP Worksheet O Line 9 & 10, (Note K)	282,183			
257	Acct. 9260057 PBOP Medicare Subsidy	PBOP Worksheet O Line 11, (Note K)	_			
258	PBOP Expense Billed From AEPSC	PBOP Worksheet O Line 13, (Note K)	32,337			
259	Acct. 928, Reg. Com. Exp.	323.189.b	-			
260	Acct. 930.1, Gen. Advert. Exp.	323.191.b	2,937			
261	Acct. 930.2, Misc. Gen. Exp.	323.192.b	77,627			
262	Balance of A & G	(In 254 - sum In 255 to In 261)	2,128,141	W/S	0.07846	166,964
		·				•
263	Plus: Acct. 924, Property Insurance	(In 255)	208,083	GP(h)	0.39294	81,764
264	Acct. 928 - Transmission Specific	Worksheet F In 18.(E) (Note L)	-	TP	1.00000	-
265	Acct 930.1 - Only safety related ads -Direct	Worksheet F In 29.(E) (Note L)	-	TP	1.00000	-
266	Acct 930.2 - Misc Gen. Exp Trans	Worksheet F In 35.(E) (Note L)	632	DA	1.00000	632
267	Settlement Approved PBOP Recovery	PBOP Worksheet O, Col. C, Line 7, (Note M)	369,968	W/S	0.07846	29,026
268	A & G Subtotal	(sum Ins 262 to 267)	2,706,824			278,387
269	O & M EXPENSE SUBTOTAL	(In 253 + In 268)	3,962,369			1,533,932
270	Plus: TEA Settlement in Account 565	Company Records (Note H)	5,302,303	DA	1.00000	1,555,552
		· · · · · · · · · · · · · · · · · · ·		DA		-
271 272	Plus: Transmission Lease Payments To Affiliates in TOTAL O & M EXPENSE	(In 269 + In 270 + In 271)	3,962,369	DA	1.00000	1,533,932
273	DEPRECIATION AND AMORTIZATION EXPENSE					
274	Production	336.2-6.f	-	NA	0.00000	-
275	Distribution	336.8.f	4,242,661	NA	0.00000	-
276	Transmission	336.7.f	1,970,536	TP1	1.00000	1,970,536
277	Plus: Transmission Plant-in-Service Additions (Work	(sheet I)	N/A			N/A
278	General	336.10.f	157,755	W/S	0.07846	12,377
279	Intangible	336.1.f	47,165	W/S	0.07846	3,700
280	TOTAL DEPRECIATION AND AMORTIZATION	(Ln 274+275+	6,418,117			1,986,613
200	TO THE BET REGISTION AND AMORTIZATION	276+277+278+279)	0,410,117			1,555,515
281	TAXES OTHER THAN INCOME	(Note N)				
282	Labor Related	(Note N)				
		Maylahaat II In 24 (D)	177 101	W//C	0.07046	12.007
283	Payroll	Worksheet H In 21.(D)	177,131	W/S	0.07846	13,897
284	Plant Related	Markabaat II ka 04 (0) 0 ka 05 (0)	4 700 440	D.A.		710.001
285	Property	Worksheet H In 21.(C) & In 35.(C)	1,726,413	DA	0.0000	742,994
286	Gross Receipts/Sales & Use	Worksheet H In 21.(F)	5,520,256	NA OR#X	0.00000	-
287	Other	Worksheet H In 21.(E)	527,793	GP(h)	0.39294	207,391
288	TOTAL OTHER TAXES	(sum Ins 283 to 287)	7,951,593			964,282
289	INCOME TAXES	(Note O)				
290	T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =	······	40.03%			
291	EIT=(T/(1-T)) * (1-(WCLTD/WACC)) =		59.28%			
292			39.2070			
	where WCLTD=(In 327) and WACC = (In 330)					
293	and FIT, SIT & p are as given in Note O.		4.0075			
294 295	GRCF=1 / (1 - T) = (from In 290) Amortized Investment Tax Credit (enter negative)	(FF1 p.114, ln 19.c)	1.6675			
	,					
296	Income Tax Calculation	(In 291 * In 299)	7,887,761			3,271,697
297	ITC adjustment	(In 294 * In 295)	-	NP(h)	0.42443	-
298	TOTAL INCOME TAXES	(sum Ins 296 to 297)	7,887,761			3,271,697
299	RETURN ON RATE BASE (Rate Base*WACC)	(In 243 * In 330)	13,306,474			5,519,279
300	INTEREST ON IPP CONTRIBUTION FOR CONST. (No	ote F) (Worksheet D, In 2.(B))	-	DA	1.00000	-
301	(Gains) / Losses on Sales of Plant Held for Future Use	(Worksheet N, In 4, Cols. ((F) & (H))	-			-
302	Tax Impact on Net Loss / (Gain) on Sales of Plant Held		-			-
303	TOTAL REVENUE REQUIREMENT		39,526,314			13,275,803
303	(sum lns 272, 280, 288, 298, 299, 300, 301, 302)		33,320,314			13,273,003

(sum Ins 272, 280, 288, 298, 299, 300, 301, 302)

WHEELING POWER COMPANY

SUPPORTING CALCULATIONS

ln								
No.	TRANSMISSION PLANT INCLUDED IN PJM TARIFF							
304	Total transmission plant	(ln 185)						88,587,641
305	Less transmission plant excluded from PJM Tariff (Not	,						-
306	Less transmission plant included in OATT Ancillary Ser	•	. (C)) (Note Q)					-
307	Transmission plant included in PJM Tariff	(In 304 - In 305 - In 306)	, , ,				_	88,587,641
308	Percent of transmission plant in PJM Tariff	(In 307 / In 304)					TP=	1.00000
				Payroll Billed from				
309	WAGES & SALARY ALLOCATOR (W/S)	(Note R)	Direct Payroll	AEP Service Corp.	Total			
310	Production	354.20.b	0	0	-	NA	0.00000	-
311	Transmission	354.21.b	1,068	204,657	205,725	TP	1.00000	205,725
312	Regional Market Expenses	354.22.b	0	0	-	NA	0.00000	-
313	Distribution	354.23.b	1,433,488	326,446	1,759,934	NA	0.00000	-
314	Other (Excludes A&G)	354.24,25,26.b	356,057	300,471	656,528	NA	0.00000	-
315	Total	(sum Ins 310 to 314)	1,790,613	831,574	2,622,187			205,725
316	Transmission related amount						W/S=	0.07846
316 317	Transmission related amount WEIGHTED AVERAGE COST OF CAPITAL (WACC)						W/S=	0.07846 \$
		(Worksheet L, In. 35, col. (D))				W/S=	\$
317	WEIGHTED AVERAGE COST OF CAPITAL (WACC)	(Worksheet L, In. 35, col. (D (Worksheet L, In. 40, col. (D	,,				W/S= 	
317 318	WEIGHTED AVERAGE COST OF CAPITAL (WACC) Long Term Interest		,,				W/S=	\$
317 318 319	WEIGHTED AVERAGE COST OF CAPITAL (WACC) Long Term Interest Preferred Dividends		,,				W/S=	\$
317 318 319 320 321 322	WEIGHTED AVERAGE COST OF CAPITAL (WACC) Long Term Interest Preferred Dividends Development of Common Stock:	(Worksheet L, In. 40, col. (D	,,				W/S=	\$ 1,312,500 -
317 318 319 320 321 322 323	WEIGHTED AVERAGE COST OF CAPITAL (WACC) Long Term Interest Preferred Dividends Development of Common Stock: Proprietary Capital Less: Preferred Stock Less: Account 216.1	(Worksheet L, In. 40, col. (D (FF1 p 112, Ln 16.c) (FF1 p 112, Ln 3.c) (FF1 p 112, Ln 12.c)	,,				W/S=	\$ 1,312,500 - 90,109,311 - -
317 318 319 320 321 322 323 324	WEIGHTED AVERAGE COST OF CAPITAL (WACC) Long Term Interest Preferred Dividends Development of Common Stock: Proprietary Capital Less: Preferred Stock Less: Account 216.1 Less: Account 219	(Worksheet L, In. 40, col. (D (FF1 p 112, Ln 16.c) (FF1 p 112, Ln 3.c) (FF1 p 112, Ln 12.c) (FF1 p 112, Ln 15.c)))				W/S=	\$ 1,312,500 - 90,109,311 - - (473,816)
317 318 319 320 321 322 323	WEIGHTED AVERAGE COST OF CAPITAL (WACC) Long Term Interest Preferred Dividends Development of Common Stock: Proprietary Capital Less: Preferred Stock Less: Account 216.1	(Worksheet L, In. 40, col. (D (FF1 p 112, Ln 16.c) (FF1 p 112, Ln 3.c) (FF1 p 112, Ln 12.c)))					\$ 1,312,500 - 90,109,311 - -
317 318 319 320 321 322 323 324 325	WEIGHTED AVERAGE COST OF CAPITAL (WACC) Long Term Interest Preferred Dividends Development of Common Stock: Proprietary Capital Less: Preferred Stock Less: Account 216.1 Less: Account 219	(Worksheet L, In. 40, col. (D (FF1 p 112, Ln 16.c) (FF1 p 112, Ln 3.c) (FF1 p 112, Ln 12.c) (FF1 p 112, Ln 15.c)))	•			Cost	\$ 1,312,500 - 90,109,311 - (473,816) 90,583,127
317 318 319 320 321 322 323 324 325	WEIGHTED AVERAGE COST OF CAPITAL (WACC) Long Term Interest Preferred Dividends Development of Common Stock: Proprietary Capital Less: Preferred Stock Less: Account 216.1 Less: Account 219 Common Stock	(Worksheet L, In. 40, col. (D (FF1 p 112, Ln 16.c) (FF1 p 112, Ln 3.c) (FF1 p 112, Ln 12.c) (FF1 p 112, Ln 15.c)))	\$	%		Cost (Note S)	\$ 1,312,500 - 90,109,311 - (473,816) 90,583,127 Weighted
317 318 319 320 321 322 323 324 325	WEIGHTED AVERAGE COST OF CAPITAL (WACC) Long Term Interest Preferred Dividends Development of Common Stock: Proprietary Capital Less: Preferred Stock Less: Account 216.1 Less: Account 219 Common Stock Long Term Debt (Note T) Worksheet L, In 35, col. (B))	(Worksheet L, In. 40, col. (D (FF1 p 112, Ln 16.c) (FF1 p 112, Ln 3.c) (FF1 p 112, Ln 12.c) (FF1 p 112, Ln 15.c)))	\$ 25,000,000	21.63%		Cost	\$ 1,312,500 - 90,109,311 - (473,816) 90,583,127 Weighted 0.0114
317 318 319 320 321 322 323 324 325 326 327 328	WEIGHTED AVERAGE COST OF CAPITAL (WACC) Long Term Interest Preferred Dividends Development of Common Stock: Proprietary Capital Less: Preferred Stock Less: Account 216.1 Less: Account 219 Common Stock Long Term Debt (Note T) Worksheet L, In 35, col. (B)) Preferred Stock (In 322)	(Worksheet L, In. 40, col. (D (FF1 p 112, Ln 16.c) (FF1 p 112, Ln 3.c) (FF1 p 112, Ln 12.c) (FF1 p 112, Ln 15.c)))	25,000,000	21.63% 0.00%		Cost (Note S) 0.0525	\$ 1,312,500 - 90,109,311 - (473,816) 90,583,127 Weighted 0.0114 0.0000
317 318 319 320 321 322 323 324 325	WEIGHTED AVERAGE COST OF CAPITAL (WACC) Long Term Interest Preferred Dividends Development of Common Stock: Proprietary Capital Less: Preferred Stock Less: Account 216.1 Less: Account 219 Common Stock Long Term Debt (Note T) Worksheet L, In 35, col. (B))	(Worksheet L, In. 40, col. (D (FF1 p 112, Ln 16.c) (FF1 p 112, Ln 3.c) (FF1 p 112, Ln 12.c) (FF1 p 112, Ln 15.c)))	·	21.63%		Cost (Note S)	\$ 1,312,500 - 90,109,311 - (473,816) 90,583,127 Weighted 0.0114

WHEELING POWER COMPANY

<u>Notes</u>

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

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

See Worksheet E for details.

- The annual and monthly net plant carrying charges on page 1 are used to compute the revenue requirement for RTEP sponsored upgrades or those projects receiving approved incentive-ROE's.
- C Transmission Plant balances in this study are historic as of December 31, 2012.
- The total-company balances shown for Accounts 281, 282, 283, 190 only reflect ADIT that relates to utility operations. The balance of Account 255 is reduced by prior flow throughs and is completely excluded if the utility chose to utilize amortization of tax credits against FIT expense. An exception to this is pre-1971 ITC balances, which are required to be taken as an offset to rate base. Account 281 is not allocated. In compliance with FERC Rulemaking RM02-7-000, Asset Retirement Obligation deferrals have been removed from ratebase. Transmission ADIT allocations are shown on WS B.
 - The company will not include the ADIT portion of deferred hedge gains and losses in rate base.
 - Cash Working Capital assigned to transmission is one-eighth of O&M allocated to transmission, as shown on line 253. It excludes:

 1) Load Scheduling & Dispatch Charges in account 561 that are collected in the OATT Ancilliary Services Revenue, as shown on line 250.
 - 2) AEP transmission equalization transfers, as shown on line 251
 - 3) The impact of state regulatory deferrals and amortizations, as shown on line 252
 - 4) All A&G Expenses, as shown on line 268.
- Consistent with Paragraph 657 of Order 2003-A, the amount on line 242 is equal to the balance of IPP System Upgrade Credits owed to transmission customers that made contributions toward the construction of System upgrades, and includes accrued interest and unreturned balance of contributions. The annual interest expense is included on line 300.
- Removes from the cost of service the Load Scheduling and Dispatch expenses booked to accounts 561.1 through 561.8. Expenses recorded in these accounts, with the exception of 561.4 & 561.8 (lines 180 & 181 above) are recovered in Schedule 1A, OATT ancillary services rates. See Worksheet F, lines 5 through 14, for descriptions and the Form 1 Source of these accounts' balances.
- Removes cost of transmission service provided by others to determine the basis of cash working capital on line 253. To the extent such service is incurred to provide the PJM service at issue, e.g. transmission equalization agreement, such costs are added back on lines 270 and 271 to determine the total O&M collected in the formula. The amounts on lines 270 and 271 are also excluded in the calculation of the FCR percentage calculated on lines 170 through 176.
 - The addbacks on lines 270 and 271 of activity recorded in 565 represents inter-company sales or purchases of transmission capacity necessary to meet each AEP company's transmission load relative to their available transmission capacity.
 - The company records referenced on lines 270 and 271 is the WHEELING POWER COMPANY general ledger.
- I Removes the impact of state regulatory deferrals or their amortization from O&M expense.
- J General Plant and Administrative & General expenses, other than in accounts 924, 928, and 930, will be functionalized based on the Wages & Salaries "W/S" allocator. The allocation basis for accounts 924, 928 and 930 are separately presented in the formula. A change in the allocation method for an account must be approved via a 205 filing with the FERC.
- K These deductions on lines 256 through 258 are to remove from the cost of service the expenses recorded by the company for Postemployment Benefits Other than Pensions (PBOP). See Note M below for the recoverable PBOP expense.
- Expenses reported for these A&G accounts will be included in the cost of service only to the extent they are directly assignable to transmission service. Worksheet F allocates these expense items. Acct 928 Includes Regulatory Commission expenses itemized in FERC Form-1 at page 351, column H. FERC Assessment Fees and Annual Charges shall not be allocated to transmission. Only safety-related and educational advertising costs in Account 930.1 are included in the TCOS. Account 930.2 includes the expenses incurred by the transmission function for Associated Business Development revenues given as a credit to the TCOS on Worksheet E.
- M See note K above. Per the settlement in Docket ER08-1329, recoverable PBOP expense is based on an annual total for the operating companies that is ratioed to them based on the total of actual annual PBOP costs, including charges from the AEP Service Corportation. The calculation of the recoverable amount for each company is shown on Worksheet O, and the process for updating the annual total is documented on Attachment F. Allowable PBOP Expense Formula.
- N Includes only FICA, unemployment, highway, property and other assessments charged in the current year. Gross receipts, sales & use and taxes related to income are excluded.
- O The currently effective income tax rate, where FIT is the Federal income tax rate; SIT is the State income tax rate, and p =
 - the percentage of federal income tax deductible for state income taxes. See Worksheet G for the development of the Company's composite SIT.

A utility that elected to utilize amortization of tax credits against taxable income, rather than book tax credits to Account No. 255 and reduce rate base, must reduce its income tax expense by the amount of the Amortized Investment Tax Credit (Form 1, 266.8.f)

(In 295) multiplied by (1/1-T). If the applicable tax rates are zero enter 0.

Inputs Required: FIT = 35.00%SIT= 7.74% (State Income Tax Rate or Composite SIT. Worksheet G))
p = 0.00% (percent of federal income tax deductible for state purposes)

- P Removes plant excluded from the OATT because it does not meet the PJM's definition of Transmission Facilities or is otherwise ineligible to be recovered under the OATT.
- Removes transmission plant (e.g. step-up transformers) included in the development of OATT ancillary service rates and not already removed for reasons indicated in Note P.
- R Includes functional wages & salaries billed by AEP Service Corporation for support of the operating company.
- S Long Term Debt cost rate = long-term interest (ln 318) / long term debt (ln 327). Preferred Stock cost rate = preferred dividends (ln 319) / preferred outstanding (ln 328). Common Stock cost rate (ROE) = 11.49%, the rate accepted by FERC in Docket No. ER08-1329. It includes an additional 50 basis points for remaining a member of the PJM RTO.

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

- T This note only applies to Indiana Michigan Power Company.
- U This note only applies to the true-up template.

WHEELING POWER COMPANY

Line No.							ansmission Amount		
1	REVENUE REQUIREMENT (w/o incentives)	(In 138)	Total	ΛII	oostor		\$10,427,761		
2	REVENUE CREDITS	(Note A) (Worksheet E)	Total 1,416,286	DA	1.00000	\$	1,416,286		
3	REVENUE REQUIREMENT For All Company Facilities	(In 1 less In 2)				\$	9,011,475		
12, Tran	MEMO: The Carrying Charge Calculations on lines 6 to 11 below are used in calculating project revenue requirements billed through PJM Schedule 12, Transmission Enhancement Charges. The total non-incentive revenue requirements for these projects shown on line 4 is included in the total on line 3.								
4	Revenue Requirement for PJM Schedule 12 Facilities (w	/o incentives) (Worksheet K)	-	DA	1.00000	\$	-		
5	NET PLANT CARRYING CHARGE w/o intra-AEP charge	s or credits or ROE incentives (Note B)							
6	Annual Rate	((ln 1 - ln 105 - ln 106)/ ln 48 x 100)					21.62%		
7	Monthly Rate	(ln 6 / 12)					1.80%		
8 9	NET PLANT CARRYING CHARGE ON LINE 6, w/o depr Annual Rate	reciation or ROE incentives (Note B) ((In 1 - In 105 - In 106 - In 111) / In 48 x 100)					17.53%		
10	NET PLANT CARRYING CHARGE ON LINE 9, w/o Retui	rn_income taxes or ROF incentives (Note R)							
11	Annual Rate	((In 1 - In 105 - In 106 - In 111 - In 133 - In 134) /	In 48 x 100)				5.13%		
12	ADDITIONAL REVENUE REQUIREMENT for projects w/	incentive ROE's (Note B) (Worksheet K)					-		
13		REVENUE REQUIREMENT FOR SCHED	ULE 1A CHARGES						
14	Total Load Dispatch & Scheduling (Account 561)	Line 85 Below					106,849		
15	Less: Load Dispatch - Scheduling, System Control and D	Dispatch Services (321.88.b)					5,085		
16	Less: Load Dispatch - Reliability, Planning & Standards D	Development Services (321.92.b)					-		
17	Total 561 Internally Developed Costs	(Line 14 - Line 15 - Line 16)					101,764		
	, ,	,					<u> </u>		

WHEELING POWER COMPANY

	(1)	(2)	(3)		(4)	(5)
	RATE BASE CALCULATION	Data Sources (See "General Notes")	<u>TO Total</u>	<u>All</u>	<u>ocator</u>	Total <u>Transmission</u>
Line No.	GROSS PLANT IN SERVICE		NOTE C			
18	Production	(Worksheet A In 1.E)	-	NA	0.00000	-
19	Less: Production ARO (Enter Negative)	(Worksheet A In 2.E)	<u>-</u>	NA	0.00000	_
20	Transmission	(Worksheet A In 3.E & Ln 142)	67,926,877	DA	0.00000	67,926,877
21	Less: Transmission ARO (Enter Negative)	(Worksheet A In 4.E & Ln 143)	-	TP	1.00000	-
22	Plus: Transmission Plant-in-Service Additions (Wo	·	N/A	NA	0.00000	N/A
	Plus: Additional Trans Plant on Transferred Assets	· · · · · · · · · · · · · · · · · · ·	N/A	NA NA	0.00000	N/A
23	Distribution					IN/A
24		(Worksheet A In 5.E)	127,637,585	NA NA	0.00000	-
25	Less: Distribution ARO (Enter Negative)	(Worksheet A In 6.E)	4 000 070	NA W/C	0.00000	200.705
26	General Plant	(Worksheet A In 7.E)	4,980,970	W/S	0.07846	390,785
27	Less: General Plant ARO (Enter Negative)	(Worksheet A In 8.E)	(34,819)	W/S	0.07846	(2,732)
28	Intangible Plant	(Worksheet A In 9.E)	949,242	W/S	0.07846	74,473
29	TOTAL GROSS PLANT	(sum Ins 18 to 28)	201,459,855	GP(h)= GTD=	0.33947 0.00000	68,389,403
30	ACCUMULATED DEPRECIATION AND AMORTIZAT	TION				
31	Production	(Worksheet A In 12.E)	-	NA	0.00000	-
32	Less: Production ARO (Enter Negative)	(Worksheet A In 13.E)	-	NA	0.00000	_
33	Transmission	(Worksheet A In 14.E & 28.E)	19,688,526	TP1=	1.00000	19,688,526
34	Less: Transmission ARO (Enter Negative)	(Worksheet A In 15.E)	-	TP1=	1.00000	-
35	Plus: Transmission Plant-in-Service Additions (Wo	,	N/A	DA	1.00000	N/A
	•	•	N/A N/A			
36	Plus: Additional Projected Deprec on Transferred	,		DA	1.00000	N/A
37	Plus: Additional Transmission Depreciation for 201		N/A	TP1	1.00000	N/A
38	Plus: Additional General & Intangible Depreciation	,	N/A	W/S	0.07846	N/A
39	Plus: Additional Accum Deprec on Transferred Ass	,	N/A	DA	1.00000	N/A
40	Distribution	(Worksheet A In 16.E)	40,456,536	NA	0.00000	-
41	Less: Distribution ARO (Enter Negative)	(Worksheet A In 17.E)	-	NA	0.00000	-
42	General Plant	(Worksheet A In 18.E)	2,527,268	W/S	0.07846	198,278
43	Less: General Plant ARO (Enter Negative)	(Worksheet A In 19.E)	(17,973)	W/S	0.07846	(1,410)
44	Intangible Plant	(Worksheet A In 20.E)	804,285	W/S	0.07846	63,101
45	TOTAL ACCUMULATED DEPRECIATION	(sum Ins 31 to 44)	63,458,641		•	19,948,494
40	NET DI ANT IN CEDVICE					
46	NET PLANT IN SERVICE	(1.40.1.40.1.04.1.00)				
47	Production	(ln 18 + ln 19 - ln 31 - ln 32)	-			-
48	Transmission	(ln 20 + ln 21 - ln 33 - ln 34)	48,238,351			48,238,351
49	Plus: Transmission Plant-in-Service Additions (In 2	•	N/A			N/A
50	Plus: Additional Trans Plant on Transferred Assets	s (In 23 - In 36)	N/A			N/A
51	Plus: Additional Transmission Depreciation for 201	3 (-ln 37)	N/A			N/A
52	Plus: Additional General & Intangible Depreciation	for 2013 (-ln 38)	N/A			N/A
53	Plus: Additional Accum Deprec on Transferred Ass	sets (Worksheet I) (-In 39)	N/A			N/A
54	Distribution	(ln 24 + ln 25 - ln 40 - ln 41)	87,181,049		!	
55	General Plant	(ln 26 + ln 27 - ln 42 - ln 43)	2,436,857			191,185
56	Intangible Plant	(In 28 - In 44)	144,957			11,373
57	TOTAL NET PLANT IN SERVICE	(sum Ins 47 to 56)	138,001,214	NP(h)=	0.35102	48,440,908
58	DEFERRED TAX ADJUSTMENTS TO RATE BASE	(Note D)				
59	Account No. 281.1 (enter negative)	(Worksheet B, In 2 & In 5.E)	-	NA		_
60	Account No. 282.1 (enter negative)	(Worksheet B, In 7 & In 10.E)	(25,583,410)	DA		(11,254,011)
61	Account No. 283.1 (enter negative)	(Worksheet B, In 12 & In 15.E)	(3,347,411)	DA		(313,740)
62	Account No. 190.1	(Worksheet B, In 17 & In 20.E)	2,924,783	DA		652,121
63	Account No. 255 (enter negative)	(Worksheet B, In 24 & In 25.E)	(42,106)	DA		(13,816)
64	TOTAL ADJUSTMENTS	(sum Ins 59 to 63)	(26,048,144)	DΛ		(10,929,446)
65	PLANT HELD FOR FUTURE USE	(Worksheet A In 29.E & In 30.E)	-	DA		-
66	REGULATORY ASSETS	(Worksheet A In 36. (E))	-	DA		-
67	WORKING CAPITAL	(Note E)				
68	Cash Working Capital	(1/8 * In 88)	156,943			156,943
69	Transmission Materials & Supplies	(Worksheet C, In 2.F)	1,019	TP	1.00000	1,019
70	A&G Materials & Supplies	(Worksheet C, In 3.F)	760	W/S	0.07846	1,019
70 71	Stores Expense	(Worksheet C, In 4.(D))	700		0.33947	OU
	·	, , , , , , , , , , , , , , , , , , , ,	7.046.007	GP(h)		-
72 72	Prepayments (Account 165) - Labor Allocated	(Worksheet C, In 8.G)	7,946,927	W/S	0.07846	623,480
73	Prepayments (Account 165) - Gross Plant	(Worksheet C, In 8.F)	149,255	GP(h)	0.33947	50,667
74 	Prepayments (Account 165) - Transmission Only	(Worksheet C, In 8.E)	- / - - /	DA	1.00000	-
75	Prepayments (Account 165) - Unallocable	(Worksheet C, In 8.D)	(7,710,537)	NA	0.00000	<u>-</u>
76	TOTAL WORKING CAPITAL	(sum Ins 68 to 75)	544,366			832,169
77	IPP CONTRIBUTIONS FOR CONSTRUCTION	(Note F) (Worksheet D, In 8 (B))	-	DA	1.00000	_
		(1.10.0 1) (11.011.011.00 D, 111.0 (D))		5,1	1.00000	
70	DATE BASE (sum Inc 57 64 65 66 76 77)		112 /07 /27		•	38 343 633

112,497,437

38,343,632

RATE BASE (sum Ins 57, 64, 65, 66, 76, 77)

WHEELING POWER COMPANY

(1) (2) (3) (4)

	EXPENSE, TAXES, RETURN & REVENUE	Data Sources	TOTatal	Alla		Total
Line	REQUIREMENTS CALCULATION	(See "General Notes")	TO Total	Allo	ocator	<u>Transmission</u>
No.	OPERATION & MAINTENANCE EXPENSE					
79	Production	321.80.b	101,565,867			
80	Distribution	322.156.b	5,330,356			
81	Customer Related Expense	322.164,171,178.b	3,018,334			
82	Regional Marketing Expenses	322.131.b	-			
83	Transmission	321.112.b	1,362,394			
84	TOTAL O&M EXPENSES	(sum Ins 79 to 83)	111,276,951			
85	Less: Total Account 561	(Note G) (Worksheet F, In 14.C)	106,849			
86	Less: Account 565	(Note H) 321.96.b	-			
87	Less: Regulatory Deferrals & Amortizations	(Note I) (Worksheet F, In 4.C)	-		4 00000	4 0== = 4=
88	Total O&M Allocable to Transmission	(Ins 83 - 85 - 86 - 87)	1,255,545	TP	1.00000	1,255,545
89	Administrative and General	323.197.b (Note J)	2,731,308			
90	Less: Acct. 924, Property Insurance	323.185.b	208,083			
91	Acct. 9260039 PBOP Expense	PBOP Worksheet O Line 9 & 10, (Note K)	282,183			
92	Acct. 9260057 PBOP Medicare Subsidy	PBOP Worksheet O Line 11, (Note K)	-			
93	PBOP Expense Billed From AEPSC	PBOP Worksheet O Line 13, (Note K)	32,337			
94	Acct. 928, Reg. Com. Exp.	323.189.b	-			
95	Acct. 930.1, Gen. Advert. Exp.	323.191.b	2,937			
96	Acct. 930.2, Misc. Gen. Exp.	323.192.b	77,627			
97	Balance of A & G	(In 89 - sum In 90 to In 96)	2,128,141	W/S	0.07846	166,964
98	Plus: Acct. 924, Property Insurance	(In 90)	208,083	GP(h)	0.33947	70,638
99	Acct. 928 - Transmission Specific	Worksheet F In 18.(E) (Note L)	-	TP	1.00000	-
100	Acct 930.1 - Only safety related ads -Direct	Worksheet F In 29.(E) (Note L)	-	TP	1.00000	-
101	Acct 930.2 - Misc Gen. Exp Trans	Worksheet F In 35.(E) (Note L)	632	DA	1.00000	632
102	Settlement Approved PBOP Recovery	PBOP Worksheet O, Col. C, Line 7, (Note M)	369,968	W/S	0.07846	29,026
103	A & G Subtotal	(sum Ins 97 to 102)	2,706,824			267,260
404	O A MEVERNOE OURTOTAL	(I - 00 - I - 400)	0.000.000		,	4 500 005
104	O & M EXPENSE SUBTOTAL	(In 88 + In 103)	3,962,369	DΛ	4.00000	1,522,805
105 106	Plus: TEA Settlement in Account 565	Company Records (Note H)	-	DA DA	1.00000 1.00000	-
100	Plus: Transmission Lease Payments To Affiliates in A TOTAL O & M EXPENSE	(In 104 + In 105 + In 106)	3,962,369	DA	1.00000	1,522,805
107	TOTAL O & IVI EXPLINGE	(111 104 + 111 105 + 111 100)	3,902,309			1,322,003
108	DEPRECIATION AND AMORTIZATION EXPENSE					
109	Production	336.2-6.f	-	NA	0.00000	-
110	Distribution	336.8.f	4,242,661	NA	0.00000	-
111	Transmission	336.7.f	1,970,536	TP1	1.00000	1,970,536
112	Plus: Transmission Plant-in-Service Additions (Works	heet I)	N/A			N/A
113	General	336.10.f	157,755	W/S	0.07846	12,377
114	Intangible	336.1.f	47,165	W/S	0.07846	3,700
115	TOTAL DEPRECIATION AND AMORTIZATION	(Ln 109+110+	6,418,117			1,986,613
		111+112+113+114)				
116	TAXES OTHER THAN INCOME	(Note N)				
117	Labor Related	Markahaat II la 24 (D)	477 404	\\/\C	0.07040	40.007
118	Payroll	Worksheet H In 21.(D)	177,131	W/S	0.07846	13,897
119 120	Plant Related	Worksheet H In 21.(C) & In 35.(C)	1,726,413	DA		742,994
120	Property Gross Receipts/Sales & Use	Worksheet H In 21.(F)	5,520,256	NA	0.00000	742,334
122	Other	Worksheet H In 21.(E)	527,793	GP(h)	0.33947	179,169
123	TOTAL OTHER TAXES	(sum Ins 118 to 122)	7,951,593	O 1 (11)	0.00017	936,061
120	TOTAL OTTILITY TAKES	(can me i to te izz)	7,001,000			000,001
124	INCOME TAXES	(Note O)				
125	T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =		40.03%			
126	EIT=(T/(1-T)) * (1-(WCLTD/WACC)) =		57.69%			
127	where WCLTD=(In 162) and WACC = (In 165)					
128	and FIT, SIT & p are as given in Note O.					
129	GRCF=1 / (1 - T) = (from ln 125)		1.6675			
130	Amortized Investment Tax Credit (enter negative)	(FF1 p.114, In 19.c)	-			
404	Incomo Tay Calculation	(ln 126 * ln 124)	6 404 005			0.400.605
131 132	Income Tax Calculation	(In 126 * In 134) (In 129 * In 130)	6,421,295	ND/h)	0.35403	2,188,635
132 133	ITC adjustment TOTAL INCOME TAXES	(In 129 In 130) (sum lns 131 to 132)	6,421,295	NP(h)	0.35102	2,188,635
133	TOTAL INCOME TAKES	(301111113 131 10 132)	U,421,290			۷, ۱۵۵,033
134	RETURN ON RATE BASE (Rate Base*WACC)	(In 78 * In 165)	11,130,289			3,793,648
	((a.a. 2 a.a.)	(10 100)	,			3,1 33,3 13
135	INTEREST ON IPP CONTRIBUTION FOR CONST. (No	te F) (Worksheet D, In 2.(B))	-	DA	1.00000	-
	· ·					
136	(Gains) / Losses on Sales of Plant Held for Future Use (Worksheet N, In 4, Cols. ((F) & (H))	-			-
407	Toy Impact on Not Loss //Osis) as Calas of Disattle Life	for Euturo I log (In 426 * In426)				
137	Tax Impact on Net Loss / (Gain) on Sales of Plant Held	ioi i uture use (iii 130 - III120)	-			-
138	TOTAL REVENUE REQUIREMENT	-	35,883,663			10,427,761
100	(sum Ins 107, 115, 123, 133, 134, 135)	-	33,300,000		•	10, 121,101
	(22 201, 170, 120, 101, 100)					

WHEELING POWER COMPANY

SUPPORTING CALCULATIONS

ln								
No.	TRANSMISSION PLANT INCLUDED IN PJM TARIFF							
139	Total transmission plant	(In 20)						67,926,877
140	Less transmission plant excluded from PJM Tariff (Note	P)						-
141	Less transmission plant included in OATT Ancillary Serv	ices (Worksheet A, In 23, Col.	(C)) (Note Q)					-
142	Transmission plant included in PJM Tariff	(In 139 - In 140 - In 141)						67,926,877
143	Percent of transmission plant in PJM Tariff	(In 142 / In 139)					TP	1.00000
				Payroll Billed from				
144	WAGES & SALARY ALLOCATOR (W/S)	(Note R)	Direct Payroll	AEP Service Corp.	Total			
145	Production	354.20.b	0	0	-	NA	0.00000	-
146	Transmission	354.21.b	1,068	204,657	205,725	TP	1.00000	205,725
147	Regional Market Expenses	354.22.b	0	0	-	NA	0.00000	-
148	Distribution	354.23.b	1,433,488	326,446	1,759,934	NA	0.00000	-
149	Other (Excludes A&G)	354.24,25,26.b	356,057	300,471	656,528	NA	0.00000	-
150	Total	(sum Ins 145 to 149)	1,790,613	831,574	2,622,187			205,725
151	Transmission related amount						W/S=	0.07846
152	WEIGHTED AVERAGE COST OF CAPITAL (WACC)							\$
	WEIGHTED AVERAGE COST OF CAPITAL (WACC) Long Term Interest	(Worksheet M, In. 21, col. (E))					т
152 153 154	WEIGHTED AVERAGE COST OF CAPITAL (WACC) Long Term Interest Preferred Dividends	(Worksheet M, In. 21, col. (E (Worksheet M, In. 56, col. (E	•				_	\$ 1,312,500 -
153	Long Term Interest	(Worksheet M, In. 21, col. (E (Worksheet M, In. 56, col. (E	•					т
153 154	Long Term Interest Preferred Dividends Development of Common Stock:))					1,312,500 - Average
153 154 155	Long Term Interest Preferred Dividends	(Worksheet M, In. 56, col. (E))					1,312,500
153 154 155 156	Long Term Interest Preferred Dividends Development of Common Stock: Proprietary Capital	(Worksheet M, In. 56, col. (E)) (Worksheet M, In. 1, col. (E))))					1,312,500 - Average
153 154 155 156 157	Long Term Interest Preferred Dividends Development of Common Stock: Proprietary Capital Less: Preferred Stock	(Worksheet M, In. 56, col. (E)) (Worksheet M, In. 1, col. (E)) (Worksheet M, In. 2, col. (E))))					1,312,500 - Average
153 154 155 156 157 158	Long Term Interest Preferred Dividends Development of Common Stock: Proprietary Capital Less: Preferred Stock Less: Account 216.1	(Worksheet M, In. 56, col. (E)) (Worksheet M, In. 1, col. (E)) (Worksheet M, In. 2, col. (E)) (Worksheet M, In. 3, col. (E))))					1,312,500 - Average 71,460,709 -
153 154 155 156 157 158 159	Long Term Interest Preferred Dividends Development of Common Stock: Proprietary Capital Less: Preferred Stock Less: Account 216.1 Less: Account 219	(Worksheet M, In. 56, col. (E)) (Worksheet M, In. 1, col. (E)) (Worksheet M, In. 2, col. (E)) (Worksheet M, In. 3, col. (E)) (Worksheet M, In. 4, col. (E))))	<u>Capital Structure</u>	Weighting		Cost	1,312,500 - Average 71,460,709 - - (1,272,340)
153 154 155 156 157 158 159	Long Term Interest Preferred Dividends Development of Common Stock: Proprietary Capital Less: Preferred Stock Less: Account 216.1 Less: Account 219	(Worksheet M, In. 56, col. (E)) (Worksheet M, In. 1, col. (E)) (Worksheet M, In. 2, col. (E)) (Worksheet M, In. 3, col. (E)) (Worksheet M, In. 4, col. (E))))	<u>Capital Structure '</u> Actual	<u>Weighting</u> Cap Limit		Cost (Note S)	1,312,500 - Average 71,460,709 - - (1,272,340)
153 154 155 156 157 158 159 160	Long Term Interest Preferred Dividends Development of Common Stock: Proprietary Capital Less: Preferred Stock Less: Account 216.1 Less: Account 219	(Worksheet M, In. 56, col. (E)) (Worksheet M, In. 1, col. (E)) (Worksheet M, In. 2, col. (E)) (Worksheet M, In. 3, col. (E)) (Worksheet M, In. 4, col. (E)) (In 156 - In 157 - In 158 - In 1))					1,312,500 - Average 71,460,709 (1,272,340) 72,733,049
153 154 155 156 157 158 159 160	Long Term Interest Preferred Dividends Development of Common Stock: Proprietary Capital Less: Preferred Stock Less: Account 216.1 Less: Account 219 Common Stock	(Worksheet M, In. 56, col. (E)) (Worksheet M, In. 1, col. (E)) (Worksheet M, In. 2, col. (E)) (Worksheet M, In. 3, col. (E)) (Worksheet M, In. 4, col. (E)) (In 156 - In 157 - In 158 - In 1))	Actual	Cap Limit		(Note S)	1,312,500
153 154 155 156 157 158 159 160	Long Term Interest Preferred Dividends Development of Common Stock: Proprietary Capital Less: Preferred Stock Less: Account 216.1 Less: Account 219 Common Stock Long Term Debt (Note T) W/S M, In 11, In 22, col. (E))	(Worksheet M, In. 56, col. (E)) (Worksheet M, In. 1, col. (E)) (Worksheet M, In. 2, col. (E)) (Worksheet M, In. 3, col. (E)) (Worksheet M, In. 4, col. (E)) (In 156 - In 157 - In 158 - In 1))	Actual 25.58%	Cap Limit 0.00%		(Note S)	1,312,500 - Average 71,460,709 (1,272,340) 72,733,049 Weighted 0.0134
153 154 155 156 157 158 159 160 161 162 163	Long Term Interest Preferred Dividends Development of Common Stock: Proprietary Capital Less: Preferred Stock Less: Account 216.1 Less: Account 219 Common Stock Long Term Debt (Note T) W/S M, In 11, In 22, col. (E)) Preferred Stock (In 157)	(Worksheet M, In. 56, col. (E) (Worksheet M, In. 1, col. (E)) (Worksheet M, In. 2, col. (E)) (Worksheet M, In. 3, col. (E)) (Worksheet M, In. 4, col. (E)) (In 156 - In 157 - In 158 - In 1 Average \$ 25,000,000))	Actual 25.58% 0.00%	Cap Limit 0.00% 0.00%		(Note S) 0.0525	1,312,500

WHEELING POWER COMPANY

<u>Notes</u>

<u>Letter</u>

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

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

See Worksheet E for details.

- B The annual and monthly net plant carrying charges on page 1 are used to compute the revenue requirement for RTEP sponsored upgrades or those projects receiving approved incentive-ROE's.
- C Transmission Plant balances in this study reflect the average of the balances at December 31, 2011 and December 31, 2012.
- The total-company balances shown for Accounts 281, 282, 283, 190 only reflect ADIT that relates to utility operations. The balance of Account 255 is reduced by prior flow throughs and is completely excluded if the utility chose to utilize amortization of tax credits against FIT expense. An exception to this is pre-1971 ITC balances, which are required to be taken as an offset to rate base. Account 281 is not allocated. In compliance with FERC Rulemaking RM02-7-000, Asset Retirement Obligation deferrals have been removed from ratebase. Transmission ADIT allocations are shown on WS B.

 The company will not include the ADIT portion of deferred hedge gains and losses in rate base.
- E Cash Working Capital assigned to transmission is one-eighth of O&M allocated to transmission, as shown on line 88. It excludes:
 - 1) Load Scheduling & Dispatch Charges in account 561 that are collected in the OATT Ancilliary Services Revenue, as shown on line 85.
 - 2) AEP transmission equalization transfers, as shown on line 86
 - 3) The impact of state regulatory deferrals and amortizations, as shown on line 87
 - 4) All A&G Expenses, as shown on line 103.
- F Consistent with Paragraph 657 of Order 2003-A, the amount on line 77 is equal to the balance of IPP System Upgrade Credits owed to transmission customers that made contributions toward the construction of System upgrades, and includes accrued interest and unreturned balance of contributions. The annual interest expense is included on line 135.
- Removes from the cost of service the Load Scheduling and Dispatch expenses booked to accounts 561.1 through 561.8. Expenses recorded in these accounts, with the exception of 561.4 & 561.8 (lines 15 & 16 above) are recovered in Schedule 1A, OATT ancillary services rates. See Worksheet F, lines 5 through 14, for descriptions and the Form 1 Source of these accounts' balances.
- Removes cost of transmission service provided by others to determine the basis of cash working capital on line 88. To the extent such service is incurred to provide the PJM service at issue, e.g. transmission equalization agreement, such costs are added back on lines 105 and 106 to determine the total O&M collected in the formula. The amounts on lines 105 and 106 are also excluded in the calculation of the FCR percentage calculated on lines 5 through 11.

 The addbacks on lines 105 and 106 of activity recorded in 565 represents inter-company sales or purchases of transmission capacity necessary to meet each AEP company's transmission load relative to their available transmission capacity.
 - The company records referenced on lines 105 and 106 is the WHEELING POWER COMPANY general ledger.
- I Removes the impact of state regulatory deferrals or their amortization from O&M expense. applicable only for state regulatory purposes.
- J General Plant and Administrative & General expenses, other than in accounts 924, 928, and 930, will be functionalized based on the Wages & Salaries "W/S" allocator. The allocation basis for accounts 924, 928 and 930 are separately presented in the formula. A change in the allocation method for an account must be approved via a 205 filing with the FERC.
- These deductions on lines 91 through 93 are to remove from the cost of service the expenses recorded by the company for Postemployment Benefits Other than Pensions (PBOP). See Note M below for the recoverable PBOP expense.
- Expenses reported for these A&G accounts will be included in the cost of service only to the extent they are directly assignable to transmission service. Worksheet F allocates these expense items. Acct 928 Includes Regulatory Commission expenses itemized in FERC Form-1 at page 351, column H. FERC Assessment Fees and Annual Charges shall not be allocated to transmission. Only safety-related and educational advertising costs in Account 930.1 are included in the TCOS. Account 930.2 includes the expenses incurred by the transmission function for Associated Business Development revenues given as a credit to the TCOS on Worksheet E.
- M See note K above. Per the settlement in Docket ER08-1329, recoverable PBOP expense is based on an annual total for the operating companies that is ratioed to them based on the total of actual annual PBOP costs, including charges from the AEP Service Corportation. The calculation of the recoverable amount for each company is shown on Worksheet O, and the process for updating the annual total is documented on Attachment F, Allowable PBOP Expense Formula.
- N Includes only FICA, unemployment, highway, property and other assessments charged in the current year. Gross receipts, sales & use and taxes related to income are excluded.
- The currently effective income tax rate, where FIT is the Federal income tax rate; SIT is the State income tax rate, and p = the percentage of federal income tax deductible for state income taxes. See Worksheet G for the development of the Company's composite SIT. A utility that elected to utilize amortization of tax credits against taxable income, rather than book tax credits to Account No. 255 and reduce rate base, must reduce its income tax expense by the amount of the Amortized Investment Tax Credit (Form 1, 266.8.f) (In 130) multiplied by (1/1-T). If the applicable tax rates are zero enter 0.

Inputs Required: FIT = 35.00%SIT = 7.74% (State Income Tax Rate or Composite SIT. Worksheet G))

p = 0.00% (percent of federal income tax deductible for state purposes)

- P Removes plant excluded from the OATT because it does not meet the PJM's definition of Transmission Facilities or is otherwise ineligible to be recovered under the OATT.
- Removes transmission plant (e.g. step-up transformers) included in the development of OATT ancillary service rates and not already removed for reasons indicated in Note P.
- R Includes functional wages & salaries billed by AEP Service Corporation for support of the operating company.
- Long Term Debt cost rate = long-term interest (ln 153) / long term debt (ln 162). Preferred Stock cost rate = preferred dividends (ln 154) / preferred outstanding (ln 163). Common Stock cost rate (ROE) = 11.49%, the rate accepted by FERC in Docket No. ER08-1329. It includes an additional 50 basis points for PJM RTO membership. Interest expense for the true-up WACC is based on actual expenses for the true-up year. The amount of eligible hedging gains or losses included in total interest expense is limited to five basis points of the true-up capital structure. Details and calculations of the true-up weighted average cost of capital are shown on Worksheet M. Eligible Hedging Gains and Losses are defined in the Formula Protocols in the tariff, and on Worksheet M.
- T This note only applies to Indiana Michigan Power Company.
- Per Settlement, equity for WHEELING POWER COMPANY is limited to 100% of Capital Structure. If the percentage of equity exceeds the cap, the excess is included in weighted percentage of long term debt in the capital structure.

 During the period ended December 31, 2011 the equity cap is in effect. During this period, a change in the cap percentage must be approved via a 205 filing with the FERC.

AEP East Companies Cost of Service Formula Rate Using 2012 FF1 Balances Worksheet A Supporting Plant Balances WHEELING POWER COMPANY

<u>Line</u>	(A)	(B)	(C)	(D)	(E)
Number	Rate Base Item & Supporting Balance	<u>Source of Data</u>	Balance @ December B. 31, 2012	alance @ December <u>A</u> 31, 2011	Average Balance for 2012
	etional ARO investment and accumulated depreciation				
	ment Balances				
1	Production Plant In Service	FF1, page 205 Col.(g) & pg. 204 Col. (b), ln 46	-	-	-
2	Production Asset Retirement Obligation (ARO)	FF1, page 205&204, Col.(g)&(b), Ins 15,24,34,44	-	-	-
3	Transmission Plant In Service	FF1, page 207 Col.(g) & pg. 206 Col. (b), ln 58	88,587,641	47,266,113	67,926,877
4	Transmission Asset Retirement Obligation	FF1, page 207 Col.(g) & pg. 206 Col. (b), ln 57	-	-	-
5	Distribution Plant In Service	FF1, page 207 Col.(g) & pg. 206 Col. (b), ln 75	132,072,558	123,202,612	127,637,585
6	Distribution Asset Retirement Obligation	FF1, page 207 Col.(g) & pg. 206 Col. (b), ln 74	-	-	-
7	General Plant In Service	FF1, page 207 Col.(g) & pg. 206 Col. (b), ln 99	5,034,700	4,927,240	4,980,970
8	General Asset Retirement Obligation	FF1, page 207 Col.(g) & pg. 206 Col. (b), ln 98	34,819	34,819	34,819
9	Intangible Plant In Service	FF1, page 205 Col.(g) & pg. 204 Col. (b), ln 5	982,428	916,055	949,242
10	Total Property Investment Balance	(Sum of Lines: 3, 1, 5, 7, 9)	226,677,327	176,312,020	201,494,674
11	Total ARO Balance (included in total on line 10)	(Sum of Lines: 4, 2, 6, 8)	34,819	34,819	34,819
Accumulated	d Depreciation & Amortization Balances				
12	Production Accumulated Depreciation	FF1, page 219, Ins 20-24, Col. (b)	-	-	-
13	Production ARO Accumulated Depreciation	Company Records - Note 1	-	-	-
14	Transmission Accumulated Depreciation	FF1, page 219, ln 25, Col. (b)	20,227,192	19,149,860	19,688,526
15	Transmission ARO Accumulated Depreciation	Company Records - Note 1	-	-	-
16	Distribution Accumulated Depreciation	FF1, page 219, ln 26, Col. (b)	41,591,445	39,321,627	40,456,536
17	Distribution ARO Accumulated Depreciation	Company Records - Note 1	-	-	-
18	General Accumulated Depreciation	FF1, page 219, ln 28, Col. (b)	2,531,284	2,523,251	2,527,268
19	General ARO Accumulated Depreciation	Company Records - Note 1	18,391	17,556	17,973
20	Intangible Accumulated Amortization	FF1, page 200, In 21, Col. (b)	742,028	866,541	804,285
21	Total Accumulated Depreciation or Amortization	(Sum of Lines: 14, 12, 16, 18, 20)	65,091,949	61,861,279	63,476,614
22	Total ARO Balance (included in total on line 21)	(Sum of Lines: 15, 13, 17, 19)	18,391	17,556	17,973
Generation S	Step-Up Units				
23	GSU Investment Amount	Company Records - Note 1	-	-	-
24	GSU Accumulated Depreciation	Company Records - Note 1	-	-	-
25	GSU Net Balance	(Line 23 - Line 24)	-	-	-
<u>Transmissio</u>	n Accumulated Depreciation Net of GSU Accumulated	d Depreciation			
26	Transmission Accumulated Depreciation	(Line 14 Above)	20,227,192	19,149,860	19,688,526
27	Less: GSU Accumulated Depreciation	(Line 24 Above)	-	-	-
28	Subtotal of Transmission Net of GSU	(Line 26 - Line 27)	20,227,192	19,149,860	19,688,526
Plant Held F	or Future Use				
29	Plant Held For Future Use	FF1, page 214, ln 47, Col. (d)	•	-	-
30	Transmission Plant Held For Future	Company Records - Note 1	-	-	-
Regulatory A	Assets and Liabilities Approved for Recovery In Rateb Note: Regulatory Assets & Liabilities can only be inclu-	pase ded in ratebase pursuant to a 205 filing with the FERC.			
31 32	2.5 2.5 2.5 2.5 2.5 2.5 2.5 2.5 3.6 3.6 3.6 3.6 3.6 3.6 3.6 3.6 3.6 3.6				-
33 34					-
35 36	Total Regulatory Deferrals Included in Ratebase		-	-	-
	-				

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

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

AEP East Companies Cost of Service Formula Rate Using 2012 FF1 Balances Worksheet B Supporting ADIT and ITC Balances WHEELING POWER COMPANY

	(A)	(B)	(C)	(D)	(E)
<u>Line</u> <u>Number</u>	<u>Description</u>	<u>Source</u>	Balance @ December 31, 2012	Balance @ December 31, 2011	Average Balance for 2012
1	Account 281				
2 3 4 5	Year End Utility Deferrals Less: ARO Related Deferrals Less: Other Excluded Deferrals Transmission Related Deferrals	FF1, p. 272 - 273, ln 8, Col. (k) Company Records - Note 1 Company Records - Note 1 Ln 2 - ln 3 - ln 4	-	-	- - - -
6	Account 282				
7 8 9 10	Year End Utility Deferrals Less: ARO Related Deferrals Less: Other Excluded Deferrals Transmission Related Deferrals	FF1, p. 274 - 275, In 5, Col. (k) Company Records - Note 1 Company Records - Note 1 Ln 7 - In 8 - In 9	29,722,622 (994) 14,802,472 14,921,144	21,444,197 (702) 13,858,022 7,586,877	25,583,410 (848) 14,330,247 11,254,011
11	Account 283				
12 13 14 15	Year End Utility Deferrals Less: ARO Related Deferrals Less: Other Excluded Deferrals Transmission Related Deferrals	FF1, p. 276 - 277, In 9, Col. (k) Company Records - Note 1 Company Records - Note 1 Ln 12 - In 13 - In 14	3,862,468 0 3,541,229 321,239	2,832,354 0 2,526,113 306,241	3,347,411 - 3,033,671 313,740
16	Account 190				
17 18 19 20	Year End Utility Deferrals Less: ARO Related Deferrals Less: Other Excluded Deferrals Transmission Related Deferrals	FF1, p. 234, ln 8, Col. (c) Company Records - Note 1 Company Records - Note 1 Ln 17 - ln 18 - ln 19	2,710,890 40,281 2,414,850 255,759	3,138,676 44,886 2,045,308 1,048,482	2,924,783 42,584 2,230,079 652,121
21	Account 255				
22 23 24	Year End ITC Balances Less: Balances Not Qualified for Ratebase ITC Balances Includeable Ratebase	FF1, p. 266-267, ln 8, Col. (h) Company Records - Note 1 Ln 22 - ln 23	27,057 0 27,057	57,155 0 57,155	42,106
25	Transmission Related Deferrals	Company Records - Note 1	8,892	18,739	13,816

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

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

AEP East Companies Cost of Service Formula Rate Using 2012 FF1 Balances Worksheet C Supporting Working Capital Rate Base Adjustments WHEELING POWER COMPANY

				WHEELING FOWER CO	DIVIPANT				
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(1)
			<u>Materi</u>	als & Supplies					
Line Number			<u>Source</u>	Balance @ December 31, 2012	Balance @ December 31, 2011	Average Balance for 2012			
2		Transmission Materials & Supplies	FF1, p. 227, ln 8, Col. (c) & (b)	1,614	423	1,019			
3		General Materials & Supplies	FF1, p. 227, ln 11, Col. (c) & (b)	1,519	0	760			
4		Stores Expense (Undistributed)	FF1, p. 227, ln 16, Col. (c) & (b)	0	0	-			
			<u>Prepaymen</u>	t Balance Summary					
5			Average of YE Balance	Excludable <u>Balances</u>	100% Transmission <u>Related</u>	Transmission Plant <u>Related</u>	Transmission Labor <u>Related</u>	Total Included in Ratebase (E)+(F)+(G)	
6 7 8		Totals as of December 31, 2012 Totals as of December 31, 2011 Average Balance	395,614 375,676 385,645	(7,804,737) (7,616,336) (7,710,537)	0	152,876 145,633 149,255	8,047,475 7,846,379 7,946,927	8,200,351 7,992,012 8,096,182	
9	Acc. No.	<u>Description</u>	Prepayments Account 165 - 2012 YE Balance	Balance @ 12/31/2 Excludable Balances	012 100% Transmission <u>Related</u>	Transmission Plant <u>Related</u>	Transmission Labor <u>Related</u>	Total Included in Ratebase (E)+(F)+(G)	<u>Explanation</u>
10 11 12 13 14	1650001 165000212 1650010 1650014 1650016 1650021	Prepaid Insurance Prepaid Taxes Prepaid Pension Benefits FAS 158 Qual Contra Asset FAS 112 ASSETS Prepaid Insurance - EIS	43,469 242,738 8,047,475 (8,047,475) 0 109,407	242,738 (8,047,475)		43,469 109,407	8,047,475 -	8,047,475 - -	Plant Related Insurance Policies Prepaid Taxes Prefunded Pension Expense SFAS 158 Offset Energy INS Services
10	1000021	Subtotal - Form 1, p 111.57.c	395,614	(7,804,737)	0	152,876	8,047,475	8,200,351	_
			Prepayments Account 165 -	Balance @ 12/31/ 2	<u>011</u> 100%	Transmission	Transmission	Total Included	
16	Acc. No.	<u>Description</u>	2011 <u>YE Balance</u>	Excludable <u>Balances</u>	Transmission <u>Related</u>	Plant Related	Labor Related	in Ratebase (E)+(F)+(G)	<u>Explanation</u>
17 18 19	1650001 165000211 1650010 1650014	Prepaid Insurance Prepaid Taxes Prepaid Pension Benefits FAS 158 Qual Contra Asset	38,943 230,043 7,846,379 (7,846,379)	230,043 (7,846,379)		38,943 0	7,846,379	-	Plant Related Insurance Policies Prepaid Taxes Prefunded Pension Expense SFAS 158 Offset
20 21	1650016	FAS 112 ASSETS	0	` ′ ′ ′				_	

Formula Rate WPCo WS D IPP Credits Page 19 of 36

AEP East Companies Cost of Service Formula Rate Using 2012 FF1 Balances Worksheet D Supporting IPP Credits WHEELING POWER COMPANY

<u>Line</u> <u>Number</u>	(A) <u>Description</u>	(B) <u>2012</u>
1	Net Funds from IPP Customers 12/31/2011 (2012 FORM 1, P269, line 24.b)	-
2	Interest Accrual (Company Records - Note 1)	-
3	Revenue Credits to Generators (Company Records - Note 1)	-
4 5 6	Other Adjustments Accounting Adjustment (Company Records - Note 1)	
7	Net Funds from IPP Customers 12/31/2012 (2012 FORM 1, P269, line 24.f)	-
8	Average Balance for Year as Indicated in Column ((In 1 + In 7)/2)	

Note 1 On this worksheet Company Records refers to WHEELING POWER COMPANY's general ledger.

AEP East Companies Cost of Service Formula Rate Using 2012 FF1 Balances Worksheet E Supporting Revenue Credits WHEELING POWER COMPANY

<u>Line</u> <u>Number</u>	<u>Description</u>	<u>Total</u> <u>Company</u>	Non- Transmission	Transmission
1	Account 450, Forfeited Discounts (FF1 p.300.16.(b); Company Records - Note 1)	142,741	142,741	-
2	Account 451, Miscellaneous Service Revenues (FF1 p.300.17.(b); Company Record	(5,425)	(5,425)	-
3	Account 454, Rent from Electric Property (FF1 p.300.19.(b); Company Records - Note 1)	1,482,876	1,418,426	64,450
4	Account 4560015, Associated Business Development - (Company Records - Note 1)	72,850	72,850	-
5	Account 456 - Other Electric Revenues - (Company Records - Note 1)	9,092,239	7,740,403	1,351,836
6	Subtotal - Other Operating Revenues (Company Total equals (FF1 p. 300.26.(b))	10,785,281	9,368,995	1,416,286
7	Accounts 4470004 & 5, Revenues from Grandfathered Transmission Contracts - (Company Records - Note 1)	-	- 1	-
8	Total Other Operating Revenues To Reduce Revenue Requirement	10,785,281	9,368,995	1,416,286

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

AEP East Companies Cost of Service Formula Rate Using 2012 FF1 Balances Worksheet F Supporting Allocation of Specific O&M or A&G Expenses WHEELING POWER COMPANY

	(A)	(B)	(C)	(D)	(E) 100%	(F)
<u>Line</u> Number	<u>Item No.</u>	<u>Description</u>	2012 Expense	100% Non-Transmission	Transmission Specific	Explanation
4	570005	Regulatory O&M Deferrals & Amortizations				
1 2 3	5700005	Maint Station-Reliability-Df	-			
4		Total	0			
		Detail of Account 561 Per FERC Form 1				
5	FF1 p 321.84.b	561 - Load Dispatching	0			
6	FF1 p 321.85.b	561.1 - Load Dispatch - Reliability	865			
7	FF1 p 321.86.b	561.2 - Load Dispatch - Monitor & Operate Trans System	85,294			
8	FF1 p 321.87.b	561.3 - Load Dispatch - Trans Service & Scheduling	(11)			
9	FF1 p 321.88.b	561.4 - Scheduling, System Control & Dispatch	5,085			
10	FF1 p 321.89.b	561.5 - Reliability, Planning and Standards Development	15,616			
11	FF1 p 321.90.b	561.6 - Transmission Service Studies	0			
12	FF1 p 321.91.b	561.7 - Generation Interconnection Studies	0			
13	FF1 p 321.92.b	561.8 - Reliability, Planning and Standards Development Servi	0			
14	, -	Total of Account 561	106,849			
		_		-		
		Account 928				
15	9280000	Regulatory Commission Exp	-	-	-	
16	9280001	Regulatory Commission Exp-Adm	-	-	-	
17	9280002	Regulatory Commission Exp-Case	-	-	-	
18		Total _				
10		_	<u> </u>		- _	
		Account 930.1				
19	9301000	General Advertising Expenses	263	263	-	
20	9301001	Newspaper Advertising Space	-	-	-	
21	9301007	Special Adv Space & Prod Exp	-	-	-	
22	9301008	Direct Mail and Handouts	-	-	-	
23	9301009	Fairs, Shows, and Exhibits			-	
24	9301010	Publicity	115	115	-	
25	9301011	Dedications, Tours, & Openings	-	-	-	
26 27	9301012 9301014	Public Opinion Surveys Video Communications	586 2	586 2	-	
28	9301014	Other Corporate Comm Exp	1,971	1,971	-	
	0001010	Carlot Corporate Commit 2xp	1,071	1,071		
29		Total	2,937	2,937	-	
		Account 930.2				
30	9302000	Misc General Expenses	14,907	14,907		
31	9302003	Corporate & Fiscal Expenses	1,447	•		
32	9302004	Research, Develop&Demonstr Exp	632	· · · · · · · · · · · · · · · · · · ·		
33	9302006	Assoc Bus Dev-Materials Sold	3,899			
34	9302007	Assoc Business Development Exp	56,741	56,109	632	
25		Total	77 600	76.004	600	
35		Total _	77,626	76,994	632	

Formula Rate WPCo WS G State Tax Rate Page 22 of 36

AEP East Companies

Cost of Service Formula Rate Using 2012 FF1 Balances Worksheet G Supporting - Development of Composite State Income Tax Rate WHEELING POWER COMPANY

West Virginia Corporate Income Tax Apportionment Factor - Note 2 Effective State Tax Rate	7.75% 99.85%	7.74%
State Income Tax Rate - Ohio Phase-out Factor Note 1 Apportionment Factor - Note 2 Effective State Tax Rate	0.00% 0.00% 0.00%	0.00%
Total Effective State Income Tax Rate	_	7.74%

- Note 1 The Ohio State Income Tax is being phased-out prorata 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 Activites 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 2012 FF1 Balances Worksheet H Supporting Taxes Other than Income WHELING POWER COMPANY

	(A)	(B)	(C)	(D)	(E)	(F)
Line		Total				
No.	Account	Company	Property	Labor	Other	Non-Allocable
		NOTE 1				
1	Revenue Taxes					
2	Gross Receipts Tax	3,435,001				3,435,001
	'	, ,				, ,
3	Real Estate and Personal Property Taxes					
4	Real and Personal Property - West Virginia	1,726,413	1,726,413			
5	Real and Personal Property - Other	0	-			
6	Payroll Taxes					
7	Federal Insurance Contribution (FICA)	173,332		173,332		
8	Federal Unemployment Tax	403		403		
9	State Unemployment Insurance	3,396		3,396		
Ü	Ciato Chempioyment modianes	0,000		0,000		
10	Production Taxes					
11	State Severance Taxes	-				-
12	Miscellaneous Taxes					
13	State Business & Occupation Tax	2,085,216				2,085,216
14	State Public Service Commission Fees	514,811			514,811	2,000,210
15	State Franchise Taxes	12,952			12,952	
16	State Lic/Registration Fee	30			30	
17	Misc. State and Local Tax	-			-	
18	Sales & Use	39				39
19	Federal Excise Tax	-				-
20	Michigan Single Business Tax	-				-
21	Total Taxes by Allocable Basis	7,951,593	1,726,413	177,131	527,793	5,520,256
	(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					
	<u> </u>	nctional Property Tax		Distribution	Conoral	Total
22	Functionalized Net Plant (Hist. TCOS, Lns 212 thru 222)	<u>Production</u>	Transmsission 68,360,449	Distribution 90,481,113	<u>General</u> 2,486,988	<u>Total</u> 161,328,550
	WEST VIRGINA JURISDICTION		00,000,140	30,401,110	2,400,000	101,020,000
23	Percentage of Plant in WEST VIRGINA JURISDICTION		100.00%	100.00%	100.00%	
24	Net Plant in WEST VIRGINA JURISDICTION (Ln 22 * Ln 23)		68,360,449	90,481,113	2,486,988	161,328,550
25	Less: Net Value of Exempted Generation Plant	-				
26	Taxable Property Basis (Ln 24 - Ln 25)		68,360,449	90,481,113	2,486,988	161,328,550
27	Relative Valuation Factor		100%	100%	100%	
28	Weighted Net Plant (Ln 26 * Ln 27)	-	68,360,449	90,481,113	2,486,988	
29	General Plant Allocator (Ln 28 / (Total - General Plant))	0.00%	43.04%	56.96%	-100.00%	
30	Functionalized General Plant (Ln 29 * General Plant)	-	1,070,322	1,416,666	(2,486,988)	-
31	Weighted WEST VIRGINA JURISDICTION Plant (Ln 28 + 30)	-	69,430,771	91,897,779	(0)	161,328,550
32	Functional Percentage (Ln 31/Total Ln 31)	0.00%	43.04%	56.96%		
33	Functionalized Expense in WEST VIRGINA JURISDICTION	-	742,994	983,419		1,726,413
34	Total Other Jurisdictions: (Line 5 * Net Plant Allocator)		-			
J -1	Total Other Julisalcholis. (Line J. Net Flant Allocator)		-			
35	Total Func. Property Taxes (Sum Lns 33, 34)	<u> </u>	742,994	983,419		1,726,413
		=				

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 WHEELING POWER COMPANY

(A)

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

FERC FORM 1 **Total** Line **Annual Tax Expenses by Type (Note 1)** FERC FORM 1 Reference No. Tie-Back Company **Revenue Taxes Gross Receipts Tax** 3,435,001 3,435,001 P.263 In 37 (i) Real Estate and Personal Property Taxes 1,726,413 Real and Personal Property - West Virginia 859,318 P.263 In 26 (i) 868,776 P.263 In 27 (i) (6,679)P.263 In 31 (i) 4,998 P.263 In 32 (i) Real and Personal Property - Ohio Payroll Taxes Federal Insurance Contribution (FICA) 173,332 173,332 P.263 In 4 (i) Federal Unemployment Tax 403 403 P.263 In 5 (i) 9 3,396 State Unemployment Insurance 3,396 P.263 In 38 (i) **Production Taxes** 10 State Severance Taxes 11 12 Miscellaneous Taxes Muni Business & Occupation Tax 2,085,216 2,085,216 P.263.1 In 8 (i) State Public Service Commission Fees 514,811 P.263 In 39 (i) 222,595 292,216 P.263 In 40 (i) 12,952 State Franchise Taxes P.263 In 23 (i) (84) P.263 In 24 (i) 1,036 P.263.1 ln 9 (i) 6,000 P.263.1 ln 10 (i) 6,000 State Lic/Registration Fee 30 25 P.263.1 In 2 (i) P.263.1 ln 11 (i) 15 P.263.1 In 15 (i) (25) P.263.1 In 17 (i) 15 Misc. State and Local Tax 17 Sales & Use 39 18 P.263 In 35 (i) 39 Federal Excise Tax 19 Michigan Single Business Tax 20 7,951,593 7,951,593 Total Taxes by Allocable Basis

(B)

(C)

(D)

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 2012 FF1 Balances Worksheet I Supporting Transmission Plant in Service Additions WHEELING POWER COMPANY

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(1)

I. Calculation of Composite Depreciation Rate

1	Transmission Plant @ Beginning of Historic Period (2012) (P.206, In 58,(b)):	47,266,113
2	Transmission Plant @ End of Historic Period (2012) (P.207, In 58,(g)):	88,587,641
3		135,853,754
4	Average Balance of Transmission Investment	67,926,877
5	Annual Depreciation Expense, Historic TCOS, In 276	1,970,536
6	Composite Depreciation Rate	2.90%
7	Round to 2.9% to Reflect a Composite Life of 34 Years	2.90%

II. Calculation of Property Placed in Service by Month and the Related Depreciation Expense

				Composite Annual					First Year
8	Month in Service	Capi	talized Balance	Depreciation Rate	Annual Depreciation	Moi	nthly Depreciation	No. Months Depreciation	Depreciation Expense
9	January	\$	5,311,421	2.90%	\$ 154,031	\$	12,836	11	\$ 141,196
10	February	\$	8,837,046	2.90%	\$ 256,274	\$	21,356	10	\$ 213,560
11	March	\$	1,453,035	2.90%	\$ 42,138	\$	3,512	9	\$ 31,608
12	April	\$	1,069,078	2.90%	\$ 31,003	\$	2,584	8	\$ 20,672
13	May	\$	330,023	2.90%	\$ 9,571	\$	798	7	\$ 5,586
14	June	\$	244,673	2.90%	\$ 7,096	\$	591	6	\$ 3,546
15	July	\$	184,935	2.90%	\$ 5,363	\$	447	5	\$ 2,235
16	August	\$	70,282	2.90%	\$ 2,038	\$	170	4	\$ 680
17	September	\$	156,649	2.90%	\$ 4,543	\$	379	3	\$ 1,137
18	October	\$	185,596	2.90%	\$ 5,382	\$	449	2	\$ 898
19	November	\$	179,260	2.90%	\$ 5,199	\$	433	1	\$ 433
20	December	\$	295,778	2.90%	\$ 8,578	\$	715	0	\$ -
21	Investment	\$	18,317,776				De	preciation Expense	\$ 421,551

III. Plant Transferred

22	\$ -	<== I his 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

Estimated Cost

IV. List of Major Projects Expected to be In-Service in 2013

	_	(000's)	Month in Service
25 <u>Major Zonal Projects</u> 26 N/A 27	Subtotal	\$0 \$0	_ Multiple
28 PJM Socialized/Beneficiary Allocated Regional Projects 29 N/A 30	Subtotal	\$0 \$0	_

AEP East Companies Cost of Service Formula Rate Using 2012 FF1 Balances Worksheet J Supporting Calculation of PROJECTED PJM RTEP Project Revenue Requirement Billed to Benefiting Zones WHEELING POWER COMPANY

SUMMARY OF PROJECTED ANNUAL RTEP REVENUE REQUIREMENTS

393,660

PROJECTED YEAR

Incentive Amounts

393,660 \$

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, In 164)

Project ROE Incentive Adder

ROE with additional basis point incentive

11.49%

-==ROE Adder Cannot Exceed 125 Basis Points

11.49%
-== 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)

	<u>%</u>	<u>Cost</u>	<u>Weighted cost</u>
Long Term Debt	21.63%	5.25%	1.1369
Preferred Stock	0.00%	0.00%	0.0009
Common Stock	78.37%	11.49%	9.0059
		R -	10 1409

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

Rate Base (Projected TCOS, In 78)	70,338,640
R (from A. above)	10.140%
Return (Rate Base x R)	7,132,565

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

Return (from B. above)	7,132,565
Effective Tax Rate (Projected TCOS, In 126)	59.28%
Income Tax Calculation (Return x CIT)	4,228,015
ITC Adjustment	-
Income Taxes	4,228,015

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, In 1)	16,266,957
T.E.A. & Lease Payments (Projected TCOS, Lns 105 & 106)	-
Return (Projected TCOS, In 134)	7,132,565
Income Taxes (Projected TCOS, In 133)	4,228,015
Annual Revenue Requirement, Less TEA Charges, Return and Taxes	4,906,378

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

Annual Revenue Requirement, Less TEA Charges, Return and Taxes	4,906,378
Return (from I.B. above)	7,132,565
Income Taxes (from I.C. above)	4,228,015
Annual Revenue Requirement, with Basis Point ROE increase	16,266,957
Depreciation (Projected TCOS, In 111)	1,970,536
Annual Rev. Req, w/ Basis Point ROE increase, less Depreciation	14,296,421

C. Determine FCR with hypothetical basis point ROE increase.

Net Transmission Plant (Projected TCOS, In 48) Annual Revenue Requirement, with Basis Point ROE increase FCR with Basis Point increase in ROE	68,360,449 16,266,957 23.80%
Annual Rev. Req, w / Basis Point ROE increase, less Dep. FCR with Basis Point ROE increase, less Depreciation FCR less Depreciation (Projected TCOS, In 9) Incremental FCR with Basis Point ROE increase, less Depreciation	14,296,421 20.91% <u>16.46%</u> 4.45%

III. Calculation of Composite Depreciation Rate

Transmission Plant @ Beginning of Historic Period (2012) (P.206, In 58,(b)):	47,266,113
Transmission Plant @ End of Historic Period (2012) (P.207, In 58,(g)):	88,587,641
Subtotal	135,853,754
Average Transmission Plant Balance for 2012	67,926,877
Annual Depreciation Rate (Projected TCOS, In 111)	1,970,536
Composite Depreciation Rate	2.90%
Depreciable Life for Composite Depreciation Rate	34.47
Round to nearest whole year	34

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. Current Projected Year ARR (e.g. ER05-925-000) 349,494 Current Projected Year ARR w/ Incentive 349,494 Project Description: RTEP ID: b1864.1 (Two additional 345/138 kV transformers at Kammer) Current Projected Year Incentive ARR

Details 2013 Investment 2,097,000 Current Year

34 FCR w/incentives approved for these facilities, less dep. Useful life

Service Year (yyyy) Service Month (1-12) 2013 ROE increase accepted by FERC (Basis Points) FCR w/o incentives, less depreciation 16.46% 16.46% 61,676 CIAC (Yes or No) Annual Depreciation Expense

CUMULATIVE HISTORY OF	PROJECTED	ANNUAL	. REVENUE REQUIREMEN	TS:

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.

Investment Year	Beginning Balance	Depreciation Expense	Ending Balance	RTEP Rev. Req't. w/o Incentives	RTEP Rev. Req't. with Incentives **	Incentive Rev. Requirement ##	RTEP Projected Rev. Req't.From Prior Year Template w/o Incentives	RTEP Projected Rev. Req't.From Prior Year Template with Incentives **	
2013	2,097,000	5,140	2,091,860	349,494	349,494				
2014	2,091,860	61,676	2,030,184	395,878	395,878				
2015	2,030,184	61,676	1,968,507	385,725	385,725				
2016	1,968,507	61,676	1,906,831	375,572	375,572				
2017	1,906,831	61,676	1,845,154	365,419	365,419	\$ -			
2018	1,845,154	61,676	1,783,478	355,266	355,266	\$ -			
2019	1,783,478	61,676	1,721,801	345,113	345,113				
2020	1,721,801	61,676	1,660,125	334,960	334,960				
2021	1,660,125	61,676	1,598,449	324,807	324,807				
2022	1,598,449	61,676	1,536,772	314,654	314,654				
2023	1,536,772	61,676	1,475,096	304,501	304,501	\$ -			
2024	1,475,096	61,676	1,413,419	294,348	294,348	Ψ			
2025	1,413,419	61,676	1,351,743	284,195	284,195				
2026	1,351,743	61,676	1,290,066	274,042	274,042				
2027	1,290,066	61,676	1,228,390	263,889	263,889				
2028	1,228,390	61,676	1,166,713	253,736	253,736				
2029	1,166,713	61,676	1,105,037	243,584	243,584				
2030	1,105,037	61,676	1,043,360	233,431	233,431				
2031	1,043,360	61,676	981,684	223,278	223,278				
2032	981,684	61,676	920,007	213,125	213,125				
2033	920,007	61,676	858,331	202,972	202,972				
2034	858,331	61,676	796,654	192,819	192,819				
2035	796,654	61,676	734,978	182,666	182,666				
2036	734,978	61,676	673,301	172,513	172,513				
2037	673,301	61,676	611,625	162,360	162,360				
2038	611,625	61,676	549,949	152,207	152,207	\$ -			
2039	549,949	61,676	488,272	142,054	142,054	\$ -			
2040	488,272	61,676	426,596	131,901	131,901	\$ -			
2041	426,596	61,676	364,919	121,748	121,748	\$ -			
2042	364,919	61,676	303,243	111,595	111,595				
2043	303,243	61,676	241,566	101,442	101,442				
2044	241,566	61,676	179,890	91,289	91,289	\$ -			
2045	179,890	61,676	118,213	81,136	81,136				
2046	118,213	61,676	56,537	70,983	70,983				
2047	56,537	56,537	-	56,537	56,537	\$ -			
2048	-	-	-	-	-	\$ -			
2049	-	-	-	-	-	\$ -			
2050	-	-	-	_	-	\$ -			
2051	-	-	-	_	-	\$ -			
2052	_	_	_	_	-	\$ -			
2053	_	_	_	_	_	\$ -			
2054	_	_	_	_	_	\$ -			
2055	_	_	_	_	_	\$ -			
2056	_	_	_	_	_	\$ -			
2057	_	_	_	_	_	\$ -			
2058	_	_	_	_	_	\$ -			
2059	_	_	_	_	_	\$ -			
2060	_	_	_	_	_	\$ -			
2061	_	_	_	_	_	\$ -			
2062	_	_	_	_	_	\$ -			
2063	_	_	_	_	_	\$			
2064	_	_	_	_	_	\$ -			
2065					_ [\$			
2066	_					\$			
2067	-	-	_	-	-	ψ ¢			
2067	-	-	-	-	-	ψ ¢			
2069	-	-	-	-	-	ψ ¢			
2069 2070	-	-	-	-	-	ψ ¢			
2070 2071	-	-	-	-	-	Ψ ¢			
2071 2072	-	-	-	-	-	Ψ - ¢			
2012	-	-	-	-	- 1	Ψ -			

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

Project Totals

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

2,097,000

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.

8,109,239

8,109,239

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

A. Base Plan Facilities

Facilities receiving incentives accepted by FERC in Docket No.

(e.g. ER05-925-000)

Current Projected Year ARR

Current Projected Year ARR w/ Incentive

Project Description: RTEP ID: b1864.2 (West Bellaire-Brues 138 kV Circuit)

Additional Current Projected Year ARR w/ Incentive ARR

Current Projected Year ARR w/ Incentive ARR

Details										
Investment	265,000	Current Year				2013	CUMULAT	IVE HISTORY OF PROJECTED ANNUAL	REVENUE REQUIRE	MENTS:
Service Year (yyyy)		ROE increase accepte		its)		-		RY OF PROJECTED ANNUAL REVENUE		
Service Month (1-12)		FCR w/o incentives, le				16.46%		TED ARR (WITH & WITHOUT INCENTIVES		
Useful life		FCR w/incentives appr		, less dep.		16.46%		OW TO MAINTAIN HISTORY OF PROJECT	TED ARRS OVER TH	
CIAC (Yes or No)	No	Annual Depreciation E	:xpense			7,794	LIFE OF THE PR	ROJECT.		
Investment Year	Beginning Balance	Depreciation Expense	Ending Balance	RTEP Rev. Req't. w/o Incentives	RTEP Rev. Req't. with Incentives **	Incentive Rev. Requirement ##	RTEP Projected Rev. Req't.From Prior Year Template w/o Incentives	RTEP Projected Rev. Req't.From Prior Year Template with Incentives **		
2013	265,000			44,166						
2014	264,350			95,040						
2015	202,674			84,887	84,887					
2016	140,998			74,734	74,734					
2017	79,321	61,676	17,645	64,581	64,581					
2018 2019	17,645	17,645	-	17,645	17,645	\$ - ¢				
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^{**} This is the total amount that needs to be reported to PJM for billing to all regions.

2071

Project Totals

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

265,000

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.

381,052

AEP East Companies Cost of Service Formula Rate Using 2012 FF1 Balances Worksheet K Supporting Calculation of TRUE-UP PJM RTEP Project Revenue Requirement Billed to Benefiting Zones WHEELING POWER COMPANY

Page 1 of 3

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

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

ROE w/o incentives (True-l	Jp TCOS, In 164	.)	11.49%	
Project ROE Incentive Adde	er		0 <==ROE Adder Cannot Exceed 100 Basis Points	
ROE with additional 0 basis	point incentive		11.49% <== ROE Including Incentives Cannot Exceed 12.5% Until July 1, 20	012
Determine R (cost of long	term debt, cost	of preferred stock and ed	equity percentage is from the True-Up TCOS, Ins 162 through164)	
	<u>%</u>	<u>Cost</u>	Weighted cost	
Long Term Debt	25.58%	5.25%	1.343%	
Preferred Stock	0.00%	0.00%	0.000%	
Common Stock	74.42%	11.49%	<u>8.551%</u>	
		R =	= 9.894%	

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

Rate Base (True-Up TCOS, In 78)	38,343,632
R (from A. above)	9.894%
Return (Rate Base x R)	3,793,648

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

Return (from B. above)	3,793,648
Effective Tax Rate (True-Up TCOS, In 126)	57.69%
Income Tax Calculation (Return x CIT)	2,188,635
ITC Adjustment	-
Income Taxes	2,188,635

II. Calculate Net Plant Carrying Charge Rate (Fixed Charge Rate or FCR) with hypothetical 0 basis point ROE increase.

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

Annual Revenue Requirement (True-Up TCOS, In 1)	10,427,761
T.E.A. & Lease Payments (True-Up TCOS, Lns 105 & 106)	
Return (True-Up TCOS, In 134)	3,793,648
Income Taxes (True-Up TCOS, In 133)	2,188,635
Annual Revenue Requirement, Less TEA	4,445,479
Charges Return and Tayes	

B. Determine Annual Revenue Requirement with hypothetical 0 basis point increase in ROE.

Annual Revenue Requirement, Less TEA Charges, Return and Taxes	4,445,479
Return (from I.B. above)	3,793,648
Income Taxes (from I.C. above)	2,188,635
Annual Revenue Requirement, with 0 Basis Point ROE increase	10,427,761
Depreciation (True-Up TCOS, In 111)	1,970,536
Annual Rev. Req, w/ 0 Basis Point ROE	8,457,225
increase, less Depreciation	

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

Net Transmission Plant (True-Up TCOS, In 48) Annual Revenue Requirement, with 0 Basis Point ROE increase FCR with 0 Basis Point increase in ROE	48,238,351 10,427,761 21.62%
Annual Rev. Req, w / 0 Basis Point ROE increase, less Dep. FCR with 0 Basis Point ROE increase, less Depreciation FCR less Depreciation (True-Up TCOS, In 9) Incremental FCR with 0 Basis Point ROE	8,457,225 17.53% <u>17.53%</u> 0.00%
increase, less Depreciation	0.0070

III. Calculation of Composite Depreciation Rate

Transmission Plant @ Beginning of Historic Period () (P.206, In 58,(b)):	47,266,113
Transmission Plant @ End of Historic Period () (P.207, In 58,(g)):	88,587,641
Subtotal	135,853,754
Average Transmission Plant Balance for	67,926,877
Annual Depreciation Rate (True-Up TCOS, In 111)	1,970,536
Composite Depreciation Rate	2.90%
Depreciable Life for Composite Depreciation Rate	34.47
Round to nearest whole year	34

SUMMARY OF TRUED	D-UP ANNUAL REVE	NUE REQUIRE	MENTS	FOR RTEPPR	OJEC	TS	
		Rev Require	\	N Incentives		Incentive A	Amounts
TRUE-UP YEAR	2012						
As Projecte	ed in Prior Year WS J					\$	-
	Actual after True-up	\$	- 5	\$	-	\$	-
True	-up of ARR For 2012		-		-		-

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

Project Description: RTEP ID: b1864.1 (Two additional 345/138 kV transformers at Kammer)

A. Base Plan Facilities

Facilities receiving incentives accepted by FERC in Docket No. (e.g. ER05-925-000)

Rev Require 2013 W Incentives Incentive Amounts Prior Yr Projected Prior Yr True-Up True-Up Adjustment

Details			
Investment	-	Current Year	2013
Service Year (yyyy)	2013	ROE increase accepted by FERC (Basis Points)	-
Service Month (1-12)	11	FCR w/o incentives, less depreciation	17.53%
Useful life	34	FCR w/incentives approved for these facilities, less dep.	17.53%
CIAC (Yes or No)	No	Annual Depreciation Expense	-

ervice Month (1-12) seful life IAC (Yes or No)	34	FCR w/o incentives, les FCR w/incentives appro Annual Depreciation Ex	oved for these facilities,	ities, less dep.						
Investment Year	Beginning Balance	Depreciation Expense	Ending Balance	Average Balance	RTEP Rev. Req't. w/o Incentives	RTEP Rev. Req't. with Incentives **		ive Rev. ement ##		
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TRUE UP OF PROJECT REVENUE REQUIREMENT FOR PRIOR YEAR:										
CUMULATIVE HISTORY OF TRUED-UP ANNUAL REVENUE REQUIREMENTS:										
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TEMPLATE BE	LOW TO MAINTAIN H	ISTORY OF TRUED-L	IP ARRS OVER THE							
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Rev. Req't.From Prior Year WS J	RTEP Rev Req't True-up	Rev. Req't.From Prior Year WS J	RTEP Rev Req't True-up	True-up of Incentive						
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Prior Year WS J	True-up	Prior Year WS J	True-up	Incentive						
Prior Year WS J	True-up w/o Incentives	Prior Year WS J	True-up	Incentive						

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

Project Totals

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

Page 2 of 3

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: RTEP ID: b1864.2 (West Bellaire-Brues 138 kV Circuit)

Details					
Investment	-	Current Year			2013
Service Year (yyyy)	2013	ROE increase accepte	ed by FERC (Basis Points)		-
Service Month (1-12)	11	FCR w/o incentives, le	ess depreciation		17.53%
Useful life	34	FCR w/incentives appr	roved for these facilities, less dep.		17.53%
CIAC (Yes or No)	No	Annual Depreciation E	xpense		-

(Yes or No)	No	FCR w/incentives appro Annual Depreciation Ex	pense		•		17.53% -	LIFE OF THE
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
2013	-	-	-	-	-	-	-	
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True-Up Adjustment		-		-	-

Page 3 of 3

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 W TO MAINTAIN HISTORY OF TRUED-UP ARRS OVER THE JECT.

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Project Totals

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

WPCo WS K TRUE-UP RTEP RR Page 31 of 36

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

AEP East Companies Cost of Service Formula Rate Using 2012 FF1 Balances Worksheet L Supporting Projected Cost of Debt WHEELING POWER COMPANY

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

Lina	(A)	(B)	(C)	(D)	(E)
<u>Line</u> <u>Number</u>	<u>Issuance</u>	Principle Outstanding	Interest Rate	Annual Expense (See Note S on Projected Template)	<u>Notes</u>
1	Long Term Debt (FF1.p. 256-257.h)	05 000 000	5.0500/	4 040 500	
2 3	Advances From Associated Co.	25,000,000	5.250%	1,312,500	
4 5	Installment Purchase Contracts (FF1.p. 256 N/A for Wheeling Power Company	6-257.h, a)			
6	Thritish Whooming Fortion Company			-	
7 8				-	
9					
10				-	
11 12					
13				-	
14				-	
15					
16				-	
17 18				-	
19				-	
20 21					
22					
23				-	
24 25					
26					
27	Issuance Discount, Premium, & Expenses:				
28	Auction Fees	FF1.p. 256 & 257.Lines Described as I	Fees	-	
29 30	Allowable Hedge Amortization (See Ln 45 Bel Amort of Debt Discount and Expenses	ow) FF1.p. 117.63.c			
31	Amort of Debt Premimums (Enter Negative)	FF1.p. 117.65.c			
32 33	Reacquired Debt: Amortization of Loss	FF1.p. 117.64.c		-	
34	Amortization of Gain	FF1.p. 117.66.c		-	
35	Total Interest on Long Term Debt	25,000,000	5.25%	1,312,500	
36	Preferred Stock (FF1.p. 250-251)	Preferred Shares Outstanding			
37	None	-	0.00%	-	
38 39				-	
40	Dividends on Preferred Stock	-		-	
41	Net Total Hedge Gains and Losses (WS M, L			-	
42 43	Total Projected Capital Structure Balance for Signature Financial Hedge Recovery Limit - Five Basis	· •		115,583,127 0.0005	
44	Limit of Recoverable Amount	·		57,792	
45	Recoverable Hedge Amortization (Lesser o	of Ln 41 or Ln 44)		-	

AEP East Companies Transmission Cost of Service Formula Rate WHEELING POWER COMPANY

Worksheet M Supporting Calculation of Capital Structure and Weighted Average Cost of Capital Based on Average of Balances At 12/31/2011 & 12/31/2012

(A)	(B)	(C)	(D)	(E)
Line		Balances @ 12/31/2012	Balances @ 12/31/2011	Average
	pment of Average Balance of Common Equity		_	
	1 Proprietary Capital (112.16.c&d)	90,109,311	52,812,106	71,460,709
	2 Less Preferred Stock (Ln 55 Below)	0	0	-
	3 Less Account 216.1 (112.12.c&d) 4 Less Account 219.1 (112.15.c&d)	-473,816	-2,070,864	0 -1,272,340
	5 Average Balance of Common Equity	90,583,127	54,882,970	72,733,049
				, ,-
<u>Develo</u>	pment of Cost of Long Term Debt Based on A	verage Outstanding B	<u>alance</u>	
(6 Bonds (112.18.c&d)	0	0	0
	7 Less: Reacquired Bonds (112.19.c&d)	0	0	0
	8 LT Advances from Assoc. Companies (112.20.c&d)	25,000,000	25,000,000	25,000,000
	9 Senior Unsecured Notes (112.21.c&d)	0	0	0
	0 Less: Fair Value Hedges (See Note on Ln 12 below)	0	05.000.000	0 05 000 000
1	1 Total Average Debt	25,000,000	25,000,000	25,000,000
1:	2 NOTE: The balance of fair value hedges on outstand term debt included in the formula's capital structure.		e excluded from the	balance of long
4.	·	,		
	3 Annual Interest Expense for 2012 4 Interest on Long Term Debt (256-257.33.i)			1,312,500
1.	Less: Total Hedge Gain/Expense Accumulated from p 25	6-257 col (i) of FERC		1,312,300
1	Form 1 included in Ln 14 and shown in Ln 34 below.	0 207, 001. (1) 01 1 2110		_
1	6 Plus: Allowed Hedge Recovery From Ln 39 below.			-
	7 Amort of Debt Discount & Expense (117.63.c)			-
	8 Amort of Loss on Reacquired Debt (117.64.c)			-
	9 Less: Amort of Premium on Debt (117.65.c)			-
	0 Less: Amort of Gain on Reacquired Debt (117.66.c)			-
2	1 Total Interest Expense (Ln 14 + Ln 17 + Ln 18 - Ln 19	- Ln 20)		1,312,500
2	2 Average Cost of Debt for 2012 (Ln 21/Ln 11)			5.25%

CALCULATION OF RECOVERABLE HEDGE GAINS/LOSSES

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)

56 Dividends on Preferred Stock (Lns 44, 49, 54) 57 Average Cost of Preferred Stock (Ln 56/55)

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

HEDGE AMOUNTS BY ISSUANCE (FROM p. 256-257	Total Hedge	Less Excludable Amounts (See	Net Includable	Remaining Unamortized	Amortizatio	on Period
(i) of the FERC Form 1)	(Gain)/Loss for 2012	NOTE on Line 23)	Hedge Amount	Balance	Beginning	Ending
24 Senior Unsecured Notes	Ò	- 1	-			
25 Senior Unsecured Notes	(-			
26 Senior Unsecured Notes	C		-			
27 Senior Unsecured Notes	C		-			
28 Senior Unsecured Notes	C		-			
29 Senior Unsecured Notes	(-			
30 Senior Unsecured Notes	C		-			
31 Senior Unsecured Notes	(-			
32 Senior Unsecured Notes	C		-			
33 Senior Unsecured Notes	C	-	-			
34 Total Hedge Amortization 35 Hedge Gain or Loss Prior to Application of Recovery Limit		-		•		
•	P TCOS, Ln 165) otal Capital	-	97,733,049 0.0005 48,867	I		
35 Hedge Gain or Loss Prior to Application of Recovery Limit 36 Total Average Capital Structure Balance for 2012 (True-U 37 Financial Hedge Recovery Limit - Five Basis Points of To 38 Limit of Recoverable Amount 39 Recoverable Hedge Amortization (Lesser of Ln 35 or Lelopment of Cost of Preferred Stock	P TCOS, Ln 165) otal Capital	-	0.0005 48,867			
35 Hedge Gain or Loss Prior to Application of Recovery Limit 36 Total Average Capital Structure Balance for 2012 (True-U 37 Financial Hedge Recovery Limit - Five Basis Points of To 38 Limit of Recoverable Amount 39 Recoverable Hedge Amortization (Lesser of Ln 35 or Lelopment of Cost of Preferred Stock Preferred Stock	P TCOS, Ln 165) otal Capital _n 38)	- 0.009/	0.0005	.		
35 Hedge Gain or Loss Prior to Application of Recovery Limit 36 Total Average Capital Structure Balance for 2012 (True-U 37 Financial Hedge Recovery Limit - Five Basis Points of To 38 Limit of Recoverable Amount 39 Recoverable Hedge Amortization (Lesser of Ln 35 or Lelopment of Cost of Preferred Stock Preferred Stock 40 0% Series - 0 - Dividend Rate (p. 250-251. 7 & 10.a)	P TCOS, Ln 165) otal Capital _n 38)		0.0005 48,867			
35 Hedge Gain or Loss Prior to Application of Recovery Limit 36 Total Average Capital Structure Balance for 2012 (True-U 37 Financial Hedge Recovery Limit - Five Basis Points of To 38 Limit of Recoverable Amount 39 Recoverable Hedge Amortization (Lesser of Ln 35 or Lelopment of Cost of Preferred Stock Preferred Stock 40 0% Series - 0 - Dividend Rate (p. 250-251. 7 & 10.a) 41 0% Series - 0 - Par Value (p. 250-251. 8.c)	P TCOS, Ln 165) otal Capital _n 38)	0.00%	0.0005 48,867			
35 Hedge Gain or Loss Prior to Application of Recovery Limit 36 Total Average Capital Structure Balance for 2012 (True-U 37 Financial Hedge Recovery Limit - Five Basis Points of To 38 Limit of Recoverable Amount 39 Recoverable Hedge Amortization (Lesser of Ln 35 or Lelopment of Cost of Preferred Stock Preferred Stock 40 0% Series - 0 - Dividend Rate (p. 250-251. 7 & 10.a) 41 0% Series - 0 - Par Value (p. 250-251. 8.c) 42 0% Series - 0 - Shares O/S (p.250-251. 8 & 11.e)	P TCOS, Ln 165) otal Capital _n 38)		0.0005 48,867			
35 Hedge Gain or Loss Prior to Application of Recovery Limit 36 Total Average Capital Structure Balance for 2012 (True-U 37 Financial Hedge Recovery Limit - Five Basis Points of To 38 Limit of Recoverable Amount 39 Recoverable Hedge Amortization (Lesser of Ln 35 or Lelopment of Cost of Preferred Stock Preferred Stock 40 0% Series - 0 - Dividend Rate (p. 250-251. 7 & 10.a) 41 0% Series - 0 - Par Value (p. 250-251. 8 & 11.e) 42 0% Series - 0 - Shares O/S (p.250-251. 8 & 11.e) 43 0% Series - 0 - Monetary Value (Ln 41 * Ln 42)	P TCOS, Ln 165) otal Capital _n 38)		0.0005 48,867			
35 Hedge Gain or Loss Prior to Application of Recovery Limit 36 Total Average Capital Structure Balance for 2012 (True-U 37 Financial Hedge Recovery Limit - Five Basis Points of To 38 Limit of Recoverable Amount 39 Recoverable Hedge Amortization (Lesser of Ln 35 or Lelopment of Cost of Preferred Stock Preferred Stock 40 0% Series - 0 - Dividend Rate (p. 250-251. 7 & 10.a) 41 0% Series - 0 - Par Value (p. 250-251. 8.c) 42 0% Series - 0 - Shares O/S (p.250-251. 8 & 11.e)	P TCOS, Ln 165) otal Capital _n 38)		0.0005 48,867			
35 Hedge Gain or Loss Prior to Application of Recovery Limit 36 Total Average Capital Structure Balance for 2012 (True-U 37 Financial Hedge Recovery Limit - Five Basis Points of To 38 Limit of Recoverable Amount 39 Recoverable Hedge Amortization (Lesser of Ln 35 or Lelopment of Cost of Preferred Stock Preferred Stock 40 0% Series - 0 - Dividend Rate (p. 250-251. 7 & 10.a) 41 0% Series - 0 - Par Value (p. 250-251. 8.c) 42 0% Series - 0 - Shares O/S (p.250-251. 8 & 11.e) 43 0% Series - 0 - Monetary Value (Ln 41 * Ln 42) 44 0% Series - 0 - Dividend Amount (Ln 40 * Ln 43)	P TCOS, Ln 165) otal Capital _n 38)		0.0005 48,867			
35 Hedge Gain or Loss Prior to Application of Recovery Limit 36 Total Average Capital Structure Balance for 2012 (True-U 37 Financial Hedge Recovery Limit - Five Basis Points of To 38 Limit of Recoverable Amount 39 Recoverable Hedge Amortization (Lesser of Ln 35 or Lelopment of Cost of Preferred Stock Preferred Stock 40 0% Series - 0 - Dividend Rate (p. 250-251. 7 & 10.a) 41 0% Series - 0 - Par Value (p. 250-251. 8 & 11.e) 42 0% Series - 0 - Shares O/S (p.250-251. 8 & 11.e) 43 0% Series - 0 - Monetary Value (Ln 41 * Ln 42)	P TCOS, Ln 165) otal Capital _n 38)		0.0005 48,867			

0.00%

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

AEP East Companies Cost of Service Formula Rate Using 2012 FF1 Balances Worksheet N - Gains (Losses) on Sales of Plant Held For Future Use WHEELING POWER COMPANY

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

	(A)	(B)	(C) Function	(D) (E		(F)	(G) Functional	(H) Functionalized	(I) FERC
Line	Date	Property Description	(T) or (G) T = Transmission G = General	Basis Proce	eeds	(Gain) / Loss	Allocator	Proceeds (Gain) / Loss	Account
1						-	0.000%	-	
2						-	0.000%	-	
3						-	0.000%	-	
4			Net	(Gain) or Loss for 2012	2	<u> </u>		<u> </u>	

AEP East Companies

Cost of Service Formula Rate Using 2012 FF1 Balances

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

Total AEP East Operating Company PBOP Settlement Amount

48,100,000

Allocation of PBOP Settlement Amount for 2012

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 2012	Actual Expense	Allowable Expense	One Year Functional Expense (Over)/Under
	(A) (Line 14)	(B)=(A)/Total (A)	(C)=(B) * 48100000	(D)	(E)=(A) * (D)	(F)=(C) * (D)	(G)=(E) - (F)
1 APCo	11,359,793	27.78%	13,362,440	7.081%	804,397	946,207	(141,809)
2							
3 I&M	10,586,657	25.89%	12,453,006	4.206%	445,250	523,744	(78,494)
4 KPCo	2,188,039	5.35%	2,573,774	9.694%	212,116	249,511	(37,394)
5 KNGP	277,875	0.68%	326,862	13.137%	36,506	42,941	(6,436)
6 OPCo	16,164,303	39.53%	19,013,950	6.771%	1,094,477	1,287,425	(192,948)
7 WPCo	314,520	0.77%	369,968	7.846%	24,676	29,026	(4,350)
8 Sum of Lines 1 to 7	40,891,187	-	48,100,000		2,617,422	3,078,853	(461,432)

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

	<u>APCo</u>	<u>1&M</u>	<u>KPCo</u>	KNGSPT	<u>OPCo</u>	<u>WPCo</u>	AEP East Total
9 Direct Charged PBOP Expense per Actuarial Report	10,991,074	9,836,923	1,994,927	247,734	13,628,228	282,183	36,981,069
10 Additional PBOP Ledger Entries (from Company Records)	(669,581)	(45,394)	-	-	1,105,077	-	
11 Medicare Subsidy	-	-	-	-	-	-	-
12 Net Company Expense (Ln 9 + Ln 10 + Ln 11)	10,321,493	9,791,529	1,994,927	247,734	14,733,305	282,183	37,371,171
13 PBOP Expenses From AEP Service Corporation (from Company Records)	1,038,300	795,128	193,112	30,141	1,430,998	32,337	3,520,016
14 Company PBOP Expense (Ln 12 + Ln 13)	11,359,793	10,586,657	2,188,039	277,875	16,164,303	314,520	40,891,187

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.