AEP East Companies
Transmission Cost of Service Formula Rate
Utilizing Historic Cost Data for 2013 and Projected Net Plant at Year-End 2014

INDIANA MICHIGAN POWER COMPANY

Line No.			Total	Allocator			Transmission Amount
1	REVENUE REQUIREMENT (w/o incentives)	(ln 138)					$132,030,251
2	REVENUE CREDITS	(Note A) (Worksheet E)	1,276,474	DA	1.00000	$	1,276,474
3	REVENUE REQUIREMENT For All Company Facilities	(ln 1 less ln 2)				$	130,753,777

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)		4,959,187	DA	1.00000	$	4,959,187
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))					17.34%
7	Monthly Rate	(ln 6 / 12)					1.45%
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))					14.73%
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))					4.60%
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	5,792,632
15	Less: Load Dispatch - Scheduling, System Control and Dispatch Services (321.88.b)		3,174,684
16	Less: Load Dispatch - Reliability, Planning & Standards Development Services (321.92.b)		746,285
17	Total 561 Internally Developed Costs	(Line 14 - Line 15 - Line 16)	1,871,663

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Line No.	(1) **RATE BASE CALCULATION**	(2) **Data Sources (See "General Notes")**	(3) **TO Total** NOTE C	(4) **Allocator**		(5) **Total Transmission**
	GROSS PLANT IN SERVICE					
18	Production	(Worksheet A ln 1.C)	4,218,917,902	NA	0.00000	-
19	Less: Production ARO (Enter Negative)	(Worksheet A ln 2.C)	(310,217,009)	NA	0.00000	-
20	Transmission	(Worksheet A ln 3.C & Ln 142)	1,320,667,751	DA		1,245,498,339
21	Less: Transmission ARO (Enter Negative)	(Worksheet A ln 4.C& Ln 143)	-	TP	0.94308	-
22	Plus: Transmission Plant-in-Service Additions (Worksheet I, ln 21.D)		68,940,318	DA	1.00000	68,940,318
23	Plus: Additional Trans Plant on Transferred Assets (Worksheet I, ln 22.D)		-	DA	1.00000	-
24	Distribution	(Worksheet A ln 5.C)	1,624,854,859	NA	0.00000	-
25	Less: Distribution ARO (Enter Negative)	(Worksheet A ln 6.C)	-	NA	0.00000	-
26	General Plant	(Worksheet A ln 7.C)	121,220,143	W/S	0.03672	4,451,162
27	Less: General Plant ARO (Enter Negative)	(Worksheet A ln 8.C)	(172,921)	W/S	0.03672	(6,350)
28	Intangible Plant	(Worksheet A ln 9.C)	145,457,304	W/S	0.03672	5,341,142
29	TOTAL GROSS PLANT	(sum lns 18 to 28)	7,189,668,347			1,324,224,611
30	ACCUMULATED DEPRECIATION AND AMORTIZATION					
31	Production	(Worksheet A ln 12.C)	2,346,477,905	NA	0.00000	-
32	Less: Production ARO (Enter Negative)	(Worksheet A ln 13.C)	(95,090,237)	NA	0.00000	-
33	Transmission	(Worksheet A ln 14.C & 28.C)	551,316,240	**TP1=**	0.96704	533,143,399
34	Less: Transmission ARO (Enter Negative)	(Worksheet A ln 15.C)	-	**TP1=**	0.96704	-
35	Plus: Transmission Plant-in-Service Additions (Worksheet I, ln 21.I)		397,665	DA	1.00000	397,665
36	Plus: Additional Projected Deprec on Transferred Assets (Worksheet I ln. 24.D)		-	DA	1.00000	-
37	Plus: Additional Transmission Depreciation for 2014 (ln 111)		20,181,719	TP1	0.96704	19,516,476
38	Plus: Additional General & Intangible Depreciation for 2014 (ln 113 + ln 114)		19,455,911	W/S	0.03672	714,414
39	Plus: Additional Accum Deprec on Transferred Assets (Worksheet I ln 23.D)		-	DA	1.00000	-
40	Distribution	(Worksheet A ln 16.C)	499,120,014	NA	0.00000	-
41	Less: Distribution ARO (Enter Negative)	(Worksheet A ln 17.C)	-	NA	0.00000	-
42	General Plant	(Worksheet A ln 18.C)	28,844,430	W/S	0.03672	1,059,157
43	Less: General Plant ARO (Enter Negative)	(Worksheet A ln 19.C)	(144,557)	W/S	0.03672	(5,308)
44	Intangible Plant	(Worksheet A ln 20.C)	141,524,886	W/S	0.03672	5,196,745
45	TOTAL ACCUMULATED DEPRECIATION	(sum lns 31 to 44)	3,512,083,977			560,022,549
46	NET PLANT IN SERVICE					
47	Production	(ln 18 + ln 19 - ln 31 - ln 32)	1,657,313,225			-
48	Transmission	(ln 20 + ln 21 - ln 33 - ln 34)	769,351,511			712,354,940
49	Plus: Transmission Plant-in-Service Additions (ln 22 - ln 35)		68,542,653			68,542,653
50	Plus: Additional Trans Plant on Transferred Assets (ln 23 - ln 36)		-			-
51	Plus: Additional Transmission Depreciation for 2014 (-ln 37)		(20,181,719)			(19,516,476)
52	Plus: Additional General & Intangible Depreciation for 2014 (-ln 38)		(19,455,911)			(714,414)
53	Plus: Additional Accum Deprec on Transferred Assets (Worksheet I) (-ln 39)		-			-
54	Distribution	(ln 24 + ln 25 - ln 40 - ln 41)	1,125,734,845			-
55	General Plant	(ln 26 + ln 27 - ln 42 - ln 43)	92,347,349			3,390,963
56	Intangible Plant	(ln 28 - ln 44)	3,932,418			144,397
57	TOTAL NET PLANT IN SERVICE	(sum lns 47 to 56)	3,677,584,370			764,202,063
58	DEFERRED TAX ADJUSTMENTS TO RATE BASE	(Note D)				
59	Account No. 281.1 (enter negative)	(Worksheet B, ln 2 & ln 5.C)	(215,395)	NA		-
60	Account No. 282.1 (enter negative)	(Worksheet B, ln 7 & ln 10.C)	(999,904,930)	DA		(161,695,721)
61	Account No. 283.1 (enter negative)	(Worksheet B, ln 12 & ln 15.C)	(724,474,181)	DA		(11,733,485)
62	Account No. 190.1	(Worksheet B, ln 17 & ln 20.C)	759,447,349	DA		12,668,110
63	Account No. 255 (enter negative)	(Worksheet B, ln 24 & ln 25.C)	-	DA		-
64	TOTAL ADJUSTMENTS	(sum lns 59 to 63)	(965,147,157)			(160,761,096)
65	PLANT HELD FOR FUTURE USE	(Worksheet A ln 29.C & ln 30.C)	5,651,068	DA		208,360
66	REGULATORY ASSETS	(Worksheet A ln 36. (C))	-	DA		-
67	WORKING CAPITAL	(Note E)				
68	Cash Working Capital	(1/8 * ln 88)	2,512,486			2,369,481
69	Transmission Materials & Supplies	(Worksheet C, ln 2.(D))	1,405,516	TP	0.94308	1,325,517
70	A&G Materials & Supplies	(Worksheet C, ln 3.(D))	60,747	W/S	0.03672	2,231
71	Stores Expense	(Worksheet C, ln 4.(D))	-	GP(h)	0.17629	-
72	Prepayments (Account 165) - Labor Allocated	(Worksheet C, ln 6.G)	122,859,751	W/S	0.03672	4,511,368
73	Prepayments (Account 165) - Gross Plant	(Worksheet C, ln 6.F)	4,363,899	GP(h)	0.17629	769,294
74	Prepayments (Account 165) - Transmission Only	(Worksheet C, ln 6.E)	-	DA	1.00000	-
75	Prepayments (Account 165) - Unallocable	(Worksheet C, ln 6.D)	(119,889,006)	NA	0.00000	-
76	TOTAL WORKING CAPITAL	(sum lns 68 to 75)	11,313,393			8,977,890
77	IPP CONTRIBUTIONS FOR CONSTRUCTION	(Note F) (Worksheet D, ln 7.B)	(2,902,804)	DA	1.00000	(2,902,804)
78	RATE BASE (sum lns 57, 64, 65, 66, 76, 77)		2,726,498,870			609,724,413

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Line No.	(1) EXPENSE, TAXES, RETURN & REVENUE REQUIREMENTS CALCULATION	(2) Data Sources (See "General Notes")	(3) TO Total	(4) Allocator		(5) Total Transmission
	OPERATION & MAINTENANCE EXPENSE					
79	Production	321.80.b	1,420,453,474			
80	Distribution	322.156.b	55,466,714			
81	Customer Related Expense	322.164,171,178.b	47,025,627			
82	Regional Marketing Expenses	322.131.b	3,258,456			
83	Transmission	321.112.b	55,000,062			
84	TOTAL O&M EXPENSES	(sum lns 79 to 83)	1,581,204,333			
85	Less: Total Account 561	(Note G) (Worksheet F, ln 12.C)	5,792,632			
86	Less: Account 565	(Note H) 321.96.b	28,944,437			
87	Less: State Regulatory Deferrals & Amortizations	(Note I) (Worksheet F, ln 4.C)	163,108			
88	Total O&M Allocable to Transmission	(lns 83 - 85 - 86 - 87)	20,099,885	TP	0.94308	18,955,845
89	Administrative and General	323.197.b (Note J)	115,581,644			
90	Less: Acct. 924, Property Insurance	323.185.b	4,470,216			
91	Acct. 9260039 PBOP Expense	PBOP Worksheet O Line 9 & 10, (Note K)	(3,118,949)			
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)	(276,641)			
94	Acct. 928, Reg. Com. Exp.	323.189.b	11,759,489			
95	Acct. 930.1, Gen. Advert. Exp.	323.191.b	167,607			
96	Acct. 930.2, Misc. Gen. Exp.	323.192.b	5,399,463			
97	Balance of A & G	(ln 89 - sum ln 90 to ln 96)	97,180,459	W/S	0.03672	3,568,433
98	Plus: Acct. 924, Property Insurance	(ln 90)	4,470,216	GP(h)	0.17629	788,036
99	Acct. 928 - Transmission Specific	Worksheet F ln 17.(E) (Note L)	-	TP	0.94308	-
100	Acct 930.1 - Only safety related ads -Direct	Worksheet F ln 32.(E) (Note L)	-	TP	0.94308	-
101	Acct 930.2 - Misc Gen. Exp. - Trans	Worksheet F ln 40.(E) (Note L)	190,764	DA	1.00000	190,764
102	Settlement Approved PBOP Recovery	PBOP Worksheet O, Col. C, Line 3, (Note M)	11,689,019	W/S	0.03672	429,217
103	A & G Subtotal	(sum lns 97 to 102)	113,530,458			4,976,450
104	O & M EXPENSE SUBTOTAL	(ln 88 + ln 103)	133,630,343			23,932,295
105	Plus: TEA Settlement in Account 565	Company Records (Note H)	-	DA	1.00000	-
106	Plus: Transmission Lease Payments To Affiliates in Acct 565 (Company Records) (Note H)		-	DA	1.00000	-
107	TOTAL O & M EXPENSE	(ln 104 + ln 105 + ln 106)	133,630,343			23,932,295
108	DEPRECIATION AND AMORTIZATION EXPENSE					
109	Production	336.2-6.f	90,976,769	NA	0.00000	-
110	Distribution	336.8.f	45,237,596	NA	0.00000	-
111	Transmission	336.7.f	20,181,719	TP1	0.96704	19,516,476
112	Plus: Transmission Plant-in-Service Additions (Worksheet I ln 21.I)		397,665	DA	1.00000	397,665
113	General	336.10.f	4,174,505	W/S	0.03672	153,286
114	Intangible	336.1.f	15,281,406	W/S	0.03672	561,128
115	TOTAL DEPRECIATION AND AMORTIZATI0N	(Lns 109+110+111 +112+113+114)	176,249,660			20,628,556
116	TAXES OTHER THAN INCOME	(Note N)				
117	Labor Related					
118	Payroll	Worksheet H ln 22.(D)	13,919,677	W/S	0.03672	511,126
119	Plant Related					
120	Property	Worksheet H ln 22.(C) & ln 47.(C)	49,736,871	DA		9,415,795
121	Gross Receipts/Sales & Use	Worksheet H ln 22.(F)	16,607,423	NA	0.00000	-
122	Other	Worksheet H ln 22.(E)	1,875,199	GP(h)	0.17629	330,571
123	TOTAL OTHER TAXES	(sum lns 118 to 122)	82,139,170			10,257,492
124	INCOME TAXES	(Note O)				
125	T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =		39.00%			
126	EIT=(T/(1-T)) * (1-(WCLTD/WACC)) =		45.28%			
127	where WCLTD=(ln 162) and WACC = (ln 165)					
128	and FIT, SIT & p are as given in Note O.					
129	GRCF=1 / (1 - T) = (from ln 125)		1.6393			
130	Amortized Investment Tax Credit (enter negative)	(FF1 p.114, ln 19.c)	(4,930,858)			
131	Income Tax Calculation	(ln 126 * ln 134)	109,686,066			24,528,993
132	ITC adjustment	(ln 129 * ln 130)	(8,083,042)	NP(h)	0.19621	(1,585,936)
133	TOTAL INCOME TAXES	(sum lns 131 to 132)	101,603,023			22,943,057
134	RETURN ON RATE BASE (Rate Base * WACC)	(ln 78 * ln 165)	242,260,071			54,176,395
135	INTEREST ON IPP CONTRIBUTION FOR CONST. (Note F) (Worksheet D, ln 2.(B))		92,456	DA	1.00000	92,456
136	(Gains) / Losses on Sales of Plant Held for Future Use (Worksheet N, ln 4, Cols. ((F) & (H))		-			-
137	Tax Impact on (Gains) / Losses on Sales of Plant Held for Future Use (ln 136 * ln126)		-			-
138	TOTAL REVENUE REQUIREMENT (sum lns 107, 115, 123, 133, 134, 135, 136, 137)		735,974,723			132,030,251

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SUPPORTING CALCULATIONS

ln No.	TRANSMISSION PLANT INCLUDED IN PJM TARIFF							
139	Total transmission plant	(ln 20)						1,320,667,751
140	Less transmission plant excluded from PJM Tariff (Note P)							-
141	Less transmission plant included in OATT Ancillary Services (Worksheet A, ln 23, Col. (C)) (Note Q)							75,169,412
142	Transmission plant included in PJM Tariff	(ln 139 - ln 140 - ln 141)						1,245,498,339
143	Percent of transmission plant in PJM Tariff	(ln 142 / ln 139)					TP	**0.94308**

ln No.				Payroll Billed from				
144	WAGES & SALARY ALLOCATOR (W/S)	(Note R)	Direct Payroll	AEP Service Corp.	Total			
145	Production	354.20.b	137,460,439	10,861,253	148,321,692	NA	0.00000	-
146	Transmission	354.21.b	3,961,979	3,299,449	7,261,428	TP	0.94308	6,848,124
147	Regional Market Expenses	354.22.b	0	0	-	NA	0.00000	-
148	Distribution	354.23.b	18,931,814	1,634,290	20,566,104	NA	0.00000	-
149	Other (Excludes A&G)	354.24,25,26.b	5,561,395	4,786,888	10,348,283	NA	0.00000	-
150	Total	(sum lns 145 to 149)	165,915,627	20,581,880	186,497,507			6,848,124
151	Transmission related amount						W/S=	**0.03672**

ln No.						
152	WEIGHTED AVERAGE COST OF CAPITAL (WACC)					$
153	Long Term Interest	(Worksheet L, ln. 26, col. (D))				91,720,180
154	Preferred Dividends	(Worksheet L, ln. 31, col. (D))				-
155	Development of Common Stock:					
156	Proprietary Capital	(FF1 p 112, Ln 16.c)				1,922,153,922
157	Less: Preferred Stock	(FF1 p 112, Ln 3.c)				-
158	Less: Account 216.1	(FF1 p 112, Ln 12.c)				(96,036)
159	Less: Account 219	(FF1 p 112, Ln 15.c)				(15,508,738)
160	Common Stock	(ln 156 - ln 157 - ln 158 - ln 159)				1,937,758,696
161			$	%	Cost (Note S)	Weighted
162	Long Term Debt (Note T) Worksheet L, ln 26, col. (B))		1,600,281,142	45.23%	0.0573	0.0259
163	Preferred Stock (ln 157)		-	0.00%	-	0.0000
164	Common Stock (ln 160)		1,937,758,696	54.77%	11.49%	0.0629
165	Total (Sum lns 162 to 164)		3,538,039,838		WACC=	**0.0889**

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INDIANA MICHIGAN POWER COMPANY

Letter	Notes
	General Notes: a) References to data from Worksheets are indicated as: Worksheet X, Line#.Column.X
A	Revenue credits include: 1) Forfeited Discounts. 2) Miscellaneous Service Revenues. 3) Rental revenues earned on assets included in the rate base. 4) Revenues for associated business projects provided by employees whose labor and overhead costs are in the transmission cost of service. 5) Other electric revenues. 6) Revenues for grandfathered PTP contracts included in the load divisor. See Worksheet E for details.
B	The annual and monthly net plant carrying charges on page 1 are used to compute the revenue requirement for RTEP sponsored upgrades or those projects receiving approved incentive-ROE's.
C	Transmission Plant balances in this study are projected as of December 31, 2014. Other ratebase amounts are as of December 31, 2013.
D	The total-company balances shown for Accounts 281, 282, 283, 190 only reflect ADIT that relates to utility operations. The balance of Account 255 is reduced by prior flow throughs and is completely excluded if the utility chose to utilize amortization of tax credits against FIT expense. An exception to this is pre-1971 ITC balances, which are required to be taken as an offset to rate base. Account 281 is not allocated. In compliance with FERC Rulemaking RM02-7-000, Asset Retirement Obligation deferrals have been removed from ratebase. Transmission ADIT allocations are shown on WS B. The company will not include the ADIT portion of deferred hedge gains and losses in rate base.
E	Cash Working Capital assigned to transmission is one-eighth of O&M allocated to transmission, as shown on line 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.
G	Removes from the cost of service the Load Scheduling and Dispatch expenses booked to accounts 561.1 through 561.8. Expenses recorded in these accounts, with the exception of 561.4 & 561.8 (lines 15 & 16 above) are recovered in Schedule 1A, OATT ancillary services rates. See Worksheet F, lines 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.
I	Removes the impact of state regulatory deferrals or their amortization from O&M expense.
J	General Plant and Administrative & General expenses, other than in accounts 924, 928, and 930, will be functionalized based on the Wages & Salaries "W/S" allocator. The allocation basis for accounts 924, 928 and 930 are separately presented in the formula. A change in the allocation method for an account must be approved via a 205 filing with the FERC.
K	These deductions on lines 91 through 93 are to remove from the cost of service the expenses recorded by the company for Postemployment Benefits Other than Pensions (PBOP). See Note M below for the recoverable PBOP expense.
L	Expenses reported for these A&G accounts will be included in the cost of service only to the extent they are directly assignable to transmission service. Worksheet F allocates these expense items. Acct 928 Includes Regulatory Commission expenses itemized in FERC Form-1 at page 351, column H. FERC Assessment Fees and Annual Charges shall not be allocated to transmission. Only safety-related and educational advertising costs in Account 930.1 are included in the TCOS. Account 930.2 includes the expenses incurred by the transmission function for Associated Business Development revenues given as a credit to the TCOS on Worksheet E.
M	See note K above. Per the settlement in Docket ER08-1329, recoverable PBOP expense is based on an annual total for the operating companies that is ratioed to them based on the total of actual annual PBOP costs, including charges from the AEP Service Corportation. The calculation of the recoverable amount for each company is shown on Worksheet O, and the process for updating the annual total is documented on Attachment F, Allowable PBOP Expense Formula.
N	Includes only FICA, unemployment, highway, property and other assessments charged in the current year. Gross receipts, sales & use and taxes related to income are excluded.
O	The currently effective income tax rate, where FIT is the Federal income tax rate; SIT is the State income tax rate, and p = the percentage of federal income tax deductible for state income taxes. See Worksheet G for the development of the Company's composite SIT. A utility that elected to utilize amortization of tax credits against taxable income, rather than book tax credits to Account No. 255 and reduce rate base, must reduce its income tax expense by the amount of the Amortized Investment Tax Credit (Form 1, 266.8.f) (ln 130) multiplied by (1/1-T) . If the applicable tax rates are zero enter 0.

Inputs Required:	FIT =	35.00%	
	SIT=	6.15%	(State Income Tax Rate or Composite SIT. Worksheet G))
	p =	0.00%	(percent of federal income tax deductible for state purposes)

Letter	Notes
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	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.

AEP East Companies
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INDIANA MICHIGAN POWER COMPANY

Line No.			Total	Allocator			Transmission Amount
166	REVENUE REQUIREMENT (w/o incentives)	(ln 303)					$125,396,332
167	REVENUE CREDITS	(Note A) (Worksheet E)	1,276,474	DA	1.00000	$	1,276,474
168	REVENUE REQUIREMENT For All Company Facilities	(ln 166 less ln 167)				$	124,119,858

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

169	Not applicable on this template		
170	NET PLANT CARRYING CHARGE w/o intra-AEP charges or credits or ROE incentives (Note B)		
171	Annual Rate	((ln 166 - ln 270 - ln 271)/ ln 213 x 100)	17.60%
172	Monthly Rate	(ln 171 / 12)	1.47%
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)	14.86%
175	NET PLANT CARRYING CHARGE ON LINE 174, w/o Return, income taxes or ROE incentives (Note B)		
176	Annual Rate	((ln 166 - ln 270 - ln 271 - ln 276 - ln 298 - ln 299) / ln 213 x 100)	4.91%
177	Not applicable on this template		

178	**REVENUE REQUIREMENT FOR SCHEDULE 1A CHARGES**		
179	Total Load Dispatch & Scheduling (Account 561)	Line 250 Below	5,792,632
180	Less: Load Dispatch - Scheduling, System Control and Dispatch Services (321.88.b)		3,174,684
181	Less: Load Dispatch - Reliability, Planning & Standards Development Services (321.92.b)		746,285
182	Total 561 Internally Developed Costs	(Line 179 - Line 180 - Line 181)	1,871,663

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Line No.	(1) RATE BASE CALCULATION	(2) Data Sources (See "General Notes")	(3) TO Total NOTE C	(4) Allocator		(5) Total Transmission
	GROSS PLANT IN SERVICE					
183	Production	(Worksheet A ln 1.C)	4,218,917,902	NA	0.00000	-
184	Less: Production ARO (Enter Negative)	(Worksheet A ln 2.C)	(310,217,009)	NA	0.00000	-
185	Transmission	(Worksheet A ln 3.C & Ln 307)	1,320,667,751	DA		1,245,498,339
186	Less: Transmission ARO (Enter Negative)	(Worksheet A ln 4.C& Ln 308)	-	TP	0.94308	-
187	Plus: Transmission Plant-in-Service Additions (Worksheet I)		**N/A**	NA	0.00000	**N/A**
188	Plus: Additional Trans Plant on Transferred Assets (Worksheet I)		**N/A**	NA	0.00000	**N/A**
189	Distribution	(Worksheet A ln 5.C)	1,624,854,859	NA	0.00000	-
190	Less: Distribution ARO (Enter Negative)	(Worksheet A ln 6.C)	-	NA	0.00000	-
191	General Plant	(Worksheet A ln 7.C)	121,220,143	W/S	0.03672	4,451,162
192	Less: General Plant ARO (Enter Negative)	(Worksheet A ln 8.C)	(172,921)	W/S	0.03672	(6,350)
193	Intangible Plant	(Worksheet A ln 9.C)	145,457,304	W/S	0.03672	5,341,142
194	TOTAL GROSS PLANT	(sum lns 183 to 193)	7,120,728,029	**GP(h)=**	**0.176286**	1,255,284,293
				GTD=	**0.42284**	
195	ACCUMULATED DEPRECIATION AND AMORTIZATION					
196	Production	(Worksheet A ln 12.C)	2,346,477,905	NA	0.00000	-
197	Less: Production ARO (Enter Negative)	(Worksheet A ln 13.C)	(95,090,237)	NA	0.00000	-
198	Transmission	(Worksheet A ln 14.C & 28.C)	551,316,240	**TP1=**	0.96704	533,143,399
199	Less: Transmission ARO (Enter Negative)	(Worksheet A ln 15.C)	-	**TP1=**	0.96704	-
200	Plus: Transmission Plant-in-Service Additions (Worksheet I)		**N/A**	DA	1.00000	**N/A**
201	Plus: Additional Projected Deprec on Transferred Assets (Worksheet I)		**N/A**	DA	1.00000	**N/A**
202	Plus: Additional Transmission Depreciation for 2014 (ln 276)		**N/A**	TP1	0.96704	**N/A**
203	Plus: Additional General & Intangible Depreciation for 2014 (ln 275 + ln 276)		**N/A**	W/S	0.03672	**N/A**
204	Plus: Additional Accum Deprec on Transferred Assets (Worksheet I)		**N/A**	DA	1.00000	**N/A**
205	Distribution	(Worksheet A ln 16.C)	499,120,014	NA	0.00000	-
206	Less: Distribution ARO (Enter Negative)	(Worksheet A ln 17.C)	-	NA	0.00000	-
207	General Plant	(Worksheet A ln 18.C)	28,844,430	W/S	0.03672	1,059,157
208	Less: General Plant ARO (Enter Negative)	(Worksheet A ln 19.C)	(144,557)	W/S	0.03672	(5,308)
209	Intangible Plant	(Worksheet A ln 20.C)	141,524,886	W/S	0.03672	5,196,745
210	TOTAL ACCUMULATED DEPRECIATION	(sum lns 196 to 209)	3,472,048,682			539,393,993
211	NET PLANT IN SERVICE					
212	Production	(ln 183 + ln 184 - ln 196 - ln 197)	1,657,313,225			-
213	Transmission	(ln 185 + ln 186 - ln 198 - ln 199)	769,351,511			712,354,940
214	Plus: Transmission Plant-in-Service Additions (ln 187 - ln 200)		**N/A**			**N/A**
215	Plus: Additional Trans Plant on Transferred Assets (ln 188 - ln 201)		**N/A**			**N/A**
216	Plus: Additional Transmission Depreciation for 2014 (-ln 202)		**N/A**			**N/A**
217	Plus: Additional General & Intangible Depreciation for 2014 (-ln 203)		**N/A**			**N/A**
218	Plus: Additional Accum Deprec on Transferred Assets (Worksheet I) (-ln 204)		**N/A**			**N/A**
219	Distribution	(ln 189 + ln 190 - ln 205 - ln 206)	1,125,734,845			-
220	General Plant	(ln 191 + ln 192 - ln 207 - ln 208)	92,347,349			3,390,963
221	Intangible Plant	(ln 193 - ln 209)	3,932,418			144,397
222	TOTAL NET PLANT IN SERVICE	(sum lns 212 to 221)	3,648,679,347	**NP(h)=**	**0.196205**	715,890,300
223	DEFERRED TAX ADJUSTMENTS TO RATE BASE	(Note D)				
224	Account No. 281.1 (enter negative)	(Worksheet B, ln 2 & ln 5.C)	(215,395)	NA		-
225	Account No. 282.1 (enter negative)	(Worksheet B, ln 7 & ln 10.C)	(999,904,930)	DA		(161,695,721)
226	Account No. 283.1 (enter negative)	(Worksheet B, ln 12 & ln 15.C)	(724,474,181)	DA		(11,733,485)
227	Account No. 190.1	(Worksheet B, ln 17 & ln 20.C)	759,447,349	DA		12,668,110
228	Account No. 255 (enter negative)	(Worksheet B, ln 24 & ln 25.C)	-	DA		-
229	TOTAL ADJUSTMENTS	(sum lns 224 to 228)	(965,147,157)			(160,761,096)
230	PLANT HELD FOR FUTURE USE	(Worksheet A ln 29.C & ln 30.C)	5,651,068	DA		208,360
231	REGULATORY ASSETS	(Worksheet A ln 36. (C))	-	DA		-
232	WORKING CAPITAL	(Note E)				
233	Cash Working Capital	(1/8 * ln 253)	2,512,486			2,369,481
234	Transmission Materials & Supplies	(Worksheet C, ln 2.(D))	1,405,516	TP	0.94308	1,325,517
235	A&G Materials & Supplies	(Worksheet C, ln 3.(D))	60,747	W/S	0.03672	2,231
236	Stores Expense	(Worksheet C, ln 4.(D))	-	GP(h)	0.17629	-
237	Prepayments (Account 165) - Labor Allocated	(Worksheet C, ln 6.G)	122,859,751	W/S	0.03672	4,511,368
238	Prepayments (Account 165) - Gross Plant	(Worksheet C, ln 6.F)	4,363,899	GP(h)	0.17629	769,294
239	Prepayments (Account 165) - Transmission Only	(Worksheet C, ln 6.E)	-	DA	1.00000	-
240	Prepayments (Account 165) - Unallocable	(Worksheet C, ln 6.D)	(119,889,006)	NA	0.00000	-
241	TOTAL WORKING CAPITAL	(sum lns 233 to 240)	11,313,393			8,977,890
242	IPP CONTRIBUTIONS FOR CONSTRUCTION	(Note F) (Worksheet D, ln 7.B)	(2,902,804)	DA	1.00000	(2,902,804)
243	RATE BASE (sum lns 222, 229, 230, 231, 241, 242)		2,697,593,847			561,412,650

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Line No.	(1) EXPENSE, TAXES, RETURN & REVENUE REQUIREMENTS CALCULATION	(2) Data Sources (See "General Notes")	(3) TO Total	(4) Allocator		(5) Total Transmission
	OPERATION & MAINTENANCE EXPENSE					
244	Production	321.80.b	1,420,453,474			
245	Distribution	322.156.b	55,466,714			
246	Customer Related Expense	322 & 323.164,171,178.b	47,025,627			
247	Regional Marketing Expenses	322.131.b	3,258,456			
248	Transmission	321.112.b	55,000,062			
249	TOTAL O&M EXPENSES	(sum lns 244 to 248)	1,581,204,333			
250	Less: Total Account 561	(Note G) (Worksheet F, ln 12.C)	5,792,632			
251	Less: Account 565	(Note H) 321.96.b	28,944,437			
252	Less: Regulatory Deferrals & Amortizations	(Note I) (Worksheet F, ln 4.C)	163,108			
253	Total O&M Allocable to Transmission	(lns 248 - 250 - 251 - 252)	20,099,885	TP	0.94308	18,955,845
254	Administrative and General	323.197.b (Note J)	115,581,644			
255	Less: Acct. 924, Property Insurance	323.185.b	4,470,216			
256	Acct. 9260039 PBOP Expense	PBOP Worksheet O Line 9 & 10, (Note K)	(3,118,949)			
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)	(276,641)			
259	Acct. 928, Reg. Com. Exp.	323.189.b	11,759,489			
260	Acct. 930.1, Gen. Advert. Exp.	323.191.b	167,607			
261	Acct. 930.2, Misc. Gen. Exp.	323.192.b	5,399,463			
262	Balance of A & G	(ln 254 - sum ln 255 to ln 261)	97,180,459	W/S	0.03672	3,568,433
263	Plus: Acct. 924, Property Insurance	(ln 255)	4,470,216	GP(h)	0.17629	788,036
264	Acct. 928 - Transmission Specific	Worksheet F ln 17.(E) (Note L)	-	TP	0.94308	-
265	Acct 930.1 - Only safety related ads -Direct	Worksheet F ln 32.(E) (Note L)	-	TP	0.94308	-
266	Acct 930.2 - Misc Gen. Exp. - Trans	Worksheet F ln 40.(E) (Note L)	190,764	DA	1.00000	190,764
267	Settlement Approved PBOP Recovery	PBOP Worksheet O, Col. C, Line 3, (Note M)	11,689,019	W/S	0.03672	429,217
268	A & G Subtotal	(sum lns 262 to 267)	113,530,458			4,976,450
269	O & M EXPENSE SUBTOTAL	(ln 253 + ln 268)	133,630,343			23,932,295
270	Plus: TEA Settlement in Account 565	Company Records (Note H)	-	DA	1.00000	-
271	Plus: Transmission Lease Payments To Affiliates in Acct 565	(Company Records) (Note H)	-	DA	1.00000	-
272	TOTAL O & M EXPENSE	(ln 269 + ln 270 + ln 271)	133,630,343			23,932,295
273	DEPRECIATION AND AMORTIZATION EXPENSE					
274	Production	336.2-6.f	90,976,769	NA	0.00000	-
275	Distribution	336.8.f	45,237,596	NA	0.00000	-
276	Transmission	336.7.f	20,181,719	TP1	0.96704	19,516,476
277	Plus: Transmission Plant-in-Service Additions (Worksheet I)		N/A			N/A
278	General	336.10.f	4,174,505	W/S	0.03672	153,286
279	Intangible	336.1.f	15,281,406	W/S	0.03672	561,128
280	TOTAL DEPRECIATION AND AMORTIZATI0N	(Ln 274+275+ 276+277+278+279)	175,851,995			20,230,891
281	TAXES OTHER THAN INCOME	(Note N)				
282	Labor Related					
283	Payroll	Worksheet H ln 22.(D)	13,919,677	W/S	0.03672	511,126
284	Plant Related					
285	Property	Worksheet H ln 22.(C) & ln 47.(C)	49,736,871	DA		9,415,795
286	Gross Receipts/Sales & Use	Worksheet H ln 22.(F)	16,607,423	NA	0.00000	-
287	Other	Worksheet H ln 22.(E)	1,875,199	GP(h)	0.17629	330,571
288	TOTAL OTHER TAXES	(sum lns 283 to 287)	82,139,170			10,257,492
289	INCOME TAXES	(Note O)				
290	T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =		39.00%			
291	EIT=(T/(1-T)) * (1-(WCLTD/WACC)) =		45.28%			
292	where WCLTD=(ln 327) and WACC = (ln 330)					
293	and FIT, SIT & p are as given in Note O.					
294	GRCF=1 / (1 - T) = (from ln 290)		1.6393			
295	Amortized Investment Tax Credit (enter negative)	(FF1 p.114, ln 19.c)	(4,930,858)			
296	Income Tax Calculation	(ln 291 * ln 299)	108,523,227			22,585,428
297	ITC adjustment	(ln 294 * ln 295)	(8,083,042)	NP(h)	0.19621	(1,585,936)
298	TOTAL INCOME TAXES	(sum lns 296 to 297)	100,440,185			20,999,492
299	RETURN ON RATE BASE (Rate Base*WACC)	(ln 243 * ln 330)	239,691,746			49,883,706
300	INTEREST ON IPP CONTRIBUTION FOR CONST. (Note F)	(Worksheet D, ln 2.(B))	92,456	DA	1.00000	92,456
301	(Gains) / Losses on Sales of Plant Held for Future Use	(Worksheet N, ln 4, Cols. ((F) & (H))	-			-
302	Tax Impact on Net Loss / (Gain) on Sales of Plant Held for Future Use	(ln 301 * ln291)	-			-
303	TOTAL REVENUE REQUIREMENT (sum lns 272, 280, 288, 298, 299, 300, 301, 302)		731,845,895			125,396,332

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SUPPORTING CALCULATIONS

ln No.								
	TRANSMISSION PLANT INCLUDED IN PJM TARIFF							
304	Total transmission plant	(ln 185)						1,320,667,751
305	Less transmission plant excluded from PJM Tariff (Note P)							
306	Less transmission plant included in OATT Ancillary Services (Worksheet A, ln 23, Col. (C)) (Note Q)							75,169,412
307	Transmission plant included in PJM Tariff	(ln 304 - ln 305 - ln 306)						1,245,498,339
308	Percent of transmission plant in PJM Tariff	(ln 307 / ln 304)					TP=	**0.94308**
				Payroll Billed from				
309	WAGES & SALARY ALLOCATOR (W/S)	(Note R)	Direct Payroll	AEP Service Corp.	Total			
310	Production	354.20.b	137,460,439	10,861,253	148,321,692	NA	0.00000	-
311	Transmission	354.21.b	3,961,979	3,299,449	7,261,428	TP	0.94308	6,848,124
312	Regional Market Expenses	354.22.b	0	0	-	NA	0.00000	-
313	Distribution	354.23.b	18,931,814	1,634,290	20,566,104	NA	0.00000	-
314	Other (Excludes A&G)	354.24,25,26.b	5,561,395	4,786,888	10,348,283	NA	0.00000	-
315	Total	(sum lns 310 to 314)	165,915,627	20,581,880	186,497,507			6,848,124
316	Transmission related amount						W/S=	**0.03672**

ln No.						
317	WEIGHTED AVERAGE COST OF CAPITAL (WACC)					$
318	Long Term Interest	(Worksheet L, ln. 26, col. (D))				91,720,180
319	Preferred Dividends	(Worksheet L, ln. 31, col. (D))				-
320	Development of Common Stock:					
321	Proprietary Capital	(FF1 p 112, Ln 16.c)				1,922,153,922
322	Less: Preferred Stock	(FF1 p 112, Ln 3.c)				-
323	Less: Account 216.1	(FF1 p 112, Ln 12 .c)				(96,036)
324	Less: Account 219	(FF1 p 112, Ln 15.c)				(15,508,738)
325	Common Stock	(ln 321 - ln 322 - ln 323 - ln 324)				1,937,758,696
326			$	%	Cost (Note S)	Weighted
327	Long Term Debt (Note T) Worksheet L, ln 26, col. (B))		1,600,281,142	45.23%	0.0573	0.0259
328	Preferred Stock (ln 322)		-	0.00%	-	0.0000
329	Common Stock (ln 325)		1,937,758,696	54.77%	11.49%	0.0629
330	Total (Sum lns 327 to 329)		3,538,039,838		WACC=	**0.0889**

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Letter	Notes
	General Notes: a) References to data from Worksheets are indicated as: Worksheet X, Line#.Column.X
A	Revenue credits include: 1) Forfeited Discounts. 2) Miscellaneous Service Revenues. 3) Rental revenues earned on assets included in the rate base. 4) Revenues for associated business projects provided by employees whose labor and overhead costs are in the transmission cost of service. 5) Other electric revenues. 6) Revenues for grandfathered PTP contracts included in the load divisor. See Worksheet E for details.
B	The annual and monthly net plant carrying charges on page 1 are used to compute the revenue requirement for RTEP sponsored upgrades or those projects receiving approved incentive-ROE's.
C	Transmission Plant balances in this study are historic as of December 31, 2013.
D	The total-company balances shown for Accounts 281, 282, 283, 190 only reflect ADIT that relates to utility operations. The balance of Account 255 is reduced by prior flow throughs and is completely excluded if the utility chose to utilize amortization of tax credits against FIT expense. An exception to this is pre-1971 ITC balances, which are required to be taken as an offset to rate base. Account 281 is not allocated. In compliance with FERC Rulemaking RM02-7-000, Asset Retirement Obligation deferrals have been removed from ratebase. Transmission ADIT allocations are shown on WS B. The company will not include the ADIT portion of deferred hedge gains and losses in rate base.
E	Cash Working Capital assigned to transmission is one-eighth of O&M allocated to transmission, as shown on line 253. It excludes: 1) Load Scheduling & Dispatch Charges in account 561 that are collected in the OATT Ancilliary Services Revenue, as shown on line 250. 2) AEP transmission equalization transfers, as shown on line 251 3) The impact of state regulatory deferrals and amortizations, as shown on line 252 4) All A&G Expenses, as shown on line 268.
F	Consistent with Paragraph 657 of Order 2003-A, the amount on line 242 is equal to the balance of IPP System Upgrade Credits owed to transmission customers that made contributions toward the construction of System upgrades, and includes accrued interest and unreturned balance of contributions. The annual interest expense is included on line 300.
G	Removes from the cost of service the Load Scheduling and Dispatch expenses booked to accounts 561.1 through 561.8. Expenses recorded in these accounts, with the exception of 561.4 & 561.8 (lines 180 & 181 above) are recovered in Schedule 1A, OATT ancillary services rates. See Worksheet F, lines 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 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.
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.
L	Expenses reported for these A&G accounts will be included in the cost of service only to the extent they are directly assignable to transmission service. Worksheet F allocates these expense items. Acct 928 Includes Regulatory Commission expenses itemized in FERC Form-1 at page 351, column H. FERC Assessment Fees and Annual Charges shall not be allocated to transmission. Only safety-related and educational advertising costs in Account 930.1 are included in the TCOS. Account 930.2 includes the expenses incurred by the transmission function for Associated Business Development revenues given as a credit to the TCOS on Worksheet E.
M	See note K above. Per the settlement in Docket ER08-1329, recoverable PBOP expense is based on an annual total for the operating companies that is ratioed to them based on the total of actual annual PBOP costs, including charges from the AEP Service Corporation. The calculation of the recoverable amount for each company is shown on Worksheet O, and the process for updating the annual total is documented on Attachment F, Allowable PBOP Expense Formula.
N	Includes only FICA, unemployment, highway, property and other assessments charged in the current year. Gross receipts, sales & use and taxes related to income are excluded.
O	The currently effective income tax rate, where FIT is the Federal income tax rate; SIT is the State income tax rate, and p = the percentage of federal income tax deductible for state income taxes. See Worksheet G for the development of the Company's composite SIT. A utility that elected to utilize amortization of tax credits against taxable income, rather than book tax credits to Account No. 255 and reduce rate base, must reduce its income tax expense by the amount of the Amortized Investment Tax Credit (Form 1, 266.8.f) (ln 295) multiplied by (1/1-T) . If the applicable tax rates are zero enter 0.

Inputs Required:			
	FIT =	35.00%	
	SIT=	6.15%	(State Income Tax Rate or Composite SIT. Worksheet G))
	p =	0.00%	(percent of federal income tax deductible for state purposes)

Letter	Notes
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	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.

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INDIANA MICHIGAN POWER COMPANY

Line No.			Total	Allocator			Transmission Amount
1	REVENUE REQUIREMENT (w/o incentives)	(ln 138)					$125,502,776
2	REVENUE CREDITS	(Note A) (Worksheet E)	1,276,474	DA	1.00000	$	1,276,474
3	REVENUE REQUIREMENT For All Company Facilities	(ln 1 less ln 2)				$	124,226,302

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.

Line No.			Total	Allocator			Transmission Amount
4	Revenue Requirement for PJM Schedule 12 Facilities (w/o incentives) (Worksheet K)		2,973,246	DA	1.00000	$	2,973,246
5	NET PLANT CARRYING CHARGE w/o intra-AEP charges or credits or ROE incentives (Note B)						
6	Annual Rate	((ln 1 - ln 105 - ln 106)/ ln 48 x 100)					17.94%
7	Monthly Rate	(ln 6 / 12)					1.50%
8	NET PLANT CARRYING CHARGE ON LINE 6 , w/o depreciation or ROE incentives (Note B)						
9	Annual Rate	((ln 1 - ln 105 - ln 106 - ln 111) / ln 48 x 100)					15.15%
10	NET PLANT CARRYING CHARGE ON LINE 9, w/o Return, income taxes or ROE incentives (Note B)						
11	Annual Rate	((ln 1 - ln 105 - ln 106 - ln 111 - ln 133 - ln 134) / ln 48 x 100)					5.01%
12	ADDITIONAL REVENUE REQUIREMENT for projects w/ incentive ROE's (Note B) (Worksheet K)						-
13	**REVENUE REQUIREMENT FOR SCHEDULE 1A CHARGES**						
14	Total Load Dispatch & Scheduling (Account 561)	Line 85 Below					5,792,632
15	Less: Load Dispatch - Scheduling, System Control and Dispatch Services (321.88.b)						3,174,684
16	Less: Load Dispatch - Reliability, Planning & Standards Development Services (321.92.b)						746,285
17	Total 561 Internally Developed Costs	(Line 14 - Line 15 - Line 16)					1,871,663

AEP East Companies
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INDIANA MICHIGAN POWER COMPANY

Line No.	(1) RATE BASE CALCULATION	(2) Data Sources (See "General Notes")	(3) TO Total NOTE C	(4) Allocator		(5) Total Transmission
	GROSS PLANT IN SERVICE					
18	Production	(Worksheet A ln 1.E)	4,128,332,314	NA	0.00000	-
19	Less: Production ARO (Enter Negative)	(Worksheet A ln 2.E)	(306,941,486)	NA	0.00000	-
20	Transmission	(Worksheet A ln 3.E & Ln 142)	1,299,347,603	DA		1,226,424,826
21	Less: Transmission ARO (Enter Negative)	(Worksheet A ln 4.E & Ln 143)	-	TP	0.94388	-
22	Plus: Transmission Plant-in-Service Additions (Worksheet I)		**N/A**	NA	0.00000	**N/A**
23	Plus: Additional Trans Plant on Transferred Assets (Worksheet I)		**N/A**	NA	0.00000	**N/A**
24	Distribution	(Worksheet A ln 5.E)	1,589,005,156	NA	0.00000	-
25	Less: Distribution ARO (Enter Negative)	(Worksheet A ln 6.E)	-	NA	0.00000	-
26	General Plant	(Worksheet A ln 7.E)	114,515,915	W/S	0.03675	4,208,530
27	Less: General Plant ARO (Enter Negative)	(Worksheet A ln 8.E)	(172,922)	W/S	0.03675	(6,355)
28	Intangible Plant	(Worksheet A ln 9.E)	142,616,297	W/S	0.03675	5,241,236
29	TOTAL GROSS PLANT	(sum lns 18 to 28)	6,966,702,877	**GP(h)=**	**0.17740**	1,235,868,238
				GTD=	**0.00000**	
30	ACCUMULATED DEPRECIATION AND AMORTIZATION					
31	Production	(Worksheet A ln 12.E)	2,332,270,005	NA	0.00000	-
32	Less: Production ARO (Enter Negative)	(Worksheet A ln 13.E)	(89,858,645)	NA	0.00000	-
33	Transmission	(Worksheet A ln 14.E & 28.E)	544,252,276	**TP1=**	0.96824	526,968,177
34	Less: Transmission ARO (Enter Negative)	(Worksheet A ln 15.E)	-	**TP1=**	0.96824	-
35	Plus: Transmission Plant-in-Service Additions (Worksheet I)		**N/A**	DA	1.00000	**N/A**
36	Plus: Additional Projected Deprec on Transferred Assets (Worksheet I)		**N/A**	DA	1.00000	**N/A**
37	Plus: Additional Transmission Depreciation for 2014 (ln 111)		**N/A**	TP1	0.96824	**N/A**
38	Plus: Additional General & Intangible Depreciation for 2014 (ln 110 + ln 111)		**N/A**	W/S	0.03675	**N/A**
39	Plus: Additional Accum Deprec on Transferred Assets (Worksheet I)		**N/A**	DA	1.00000	**N/A**
40	Distribution	(Worksheet A ln 16.E)	489,227,742	NA	0.00000	-
41	Less: Distribution ARO (Enter Negative)	(Worksheet A ln 17.E)	-	NA	0.00000	-
42	General Plant	(Worksheet A ln 18.E)	28,072,972	W/S	0.03675	1,031,699
43	Less: General Plant ARO (Enter Negative)	(Worksheet A ln 19.E)	(141,425)	W/S	0.03675	(5,197)
44	Intangible Plant	(Worksheet A ln 20.E)	137,070,319	W/S	0.03675	5,037,418
45	TOTAL ACCUMULATED DEPRECIATION	(sum lns 31 to 44)	3,440,893,243			533,032,097
46	NET PLANT IN SERVICE					
47	Production	(ln 18 + ln 19 - ln 31 - ln 32)	1,578,979,467			-
48	Transmission	(ln 20 + ln 21 - ln 33 - ln 34)	755,095,327			699,456,649
49	Plus: Transmission Plant-in-Service Additions (ln 22 - ln 35)		**N/A**			**N/A**
50	Plus: Additional Trans Plant on Transferred Assets (ln 23 - ln 36)		**N/A**			**N/A**
51	Plus: Additional Transmission Depreciation for 2014 (-ln 37)		**N/A**			**N/A**
52	Plus: Additional General & Intangible Depreciation for 2014 (-ln 38)		**N/A**			**N/A**
53	Plus: Additional Accum Deprec on Transferred Assets (Worksheet I) (-ln 39)		**N/A**			**N/A**
54	Distribution	(ln 24 + ln 25 - ln 40 - ln 41)	1,099,777,414			-
55	General Plant	(ln 26 + ln 27 - ln 42 - ln 43)	86,411,447			3,175,674
56	Intangible Plant	(ln 28 - ln 44)	5,545,978			203,818
57	TOTAL NET PLANT IN SERVICE	(sum lns 47 to 56)	3,525,809,633	**NP(h)=**	**0.19934**	702,836,141
58	DEFERRED TAX ADJUSTMENTS TO RATE BASE	(Note D)				
59	Account No. 281.1 (enter negative)	(Worksheet B, ln 2 & ln 5.E)	(230,840)	NA		-
60	Account No. 282.1 (enter negative)	(Worksheet B, ln 7 & ln 10.E)	(959,954,107)	DA		(156,550,657)
61	Account No. 283.1 (enter negative)	(Worksheet B, ln 12 & ln 15.E)	(694,469,538)	DA		(10,579,004)
62	Account No. 190.1	(Worksheet B, ln 17 & ln 20.E)	757,607,521	DA		13,858,262
63	Account No. 255 (enter negative)	(Worksheet B, ln 24 & ln 25.E)	-	DA		-
64	TOTAL ADJUSTMENTS	(sum lns 59 to 63)	(897,046,965)			(153,271,399)
65	PLANT HELD FOR FUTURE USE	(Worksheet A ln 29.E & ln 30.E)	5,973,018	DA		208,360
66	REGULATORY ASSETS	(Worksheet A ln 36. (E))	-	DA		-
67	WORKING CAPITAL	(Note E)				
68	Cash Working Capital	(1/8 * ln 88)	2,512,486			2,371,478
69	Transmission Materials & Supplies	(Worksheet C, ln 2.F)	1,679,827	TP	0.94388	1,585,550
70	A&G Materials & Supplies	(Worksheet C, ln 3.F)	56,429	W/S	0.03675	2,074
71	Stores Expense	(Worksheet C, ln 4.(D))	-	GP(h)	0.17740	-
72	Prepayments (Account 165) - Labor Allocated	(Worksheet C, ln 8.G)	133,772,981	W/S	0.03675	4,916,239
73	Prepayments (Account 165) - Gross Plant	(Worksheet C, ln 8.F)	4,967,872	GP(h)	0.17740	881,283
74	Prepayments (Account 165) - Transmission Only	(Worksheet C, ln 8.E)	-	DA	1.00000	-
75	Prepayments (Account 165) - Unallocable	(Worksheet C, ln 8.D)	(129,648,413)	NA	0.00000	-
76	TOTAL WORKING CAPITAL	(sum lns 68 to 75)	13,341,181			9,756,624
77	IPP CONTRIBUTIONS FOR CONSTRUCTION	(Note F) (Worksheet D, ln 8 (B))	(2,856,576)	DA	1.00000	(2,856,576)
78	RATE BASE (sum lns 57, 64, 65, 66, 76, 77)		2,645,220,291			556,673,150

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INDIANA MICHIGAN POWER COMPANY

Line No.	(1) EXPENSE, TAXES, RETURN & REVENUE REQUIREMENTS CALCULATION	(2) Data Sources (See "General Notes")	(3) TO Total	(4) Allocator		(5) Total Transmission
	OPERATION & MAINTENANCE EXPENSE					
79	Production	321.80.b	1,420,453,474			
80	Distribution	322.156.b	55,466,714			
81	Customer Related Expense	322.164,171,178.b	47,025,627			
82	Regional Marketing Expenses	322.131.b	3,258,456			
83	Transmission	321.112.b	55,000,062			
84	TOTAL O&M EXPENSES	(sum lns 79 to 83)	1,581,204,333			
85	Less: Total Account 561	(Note G) (Worksheet F, ln 12.C)	5,792,632			
86	Less: Account 565	(Note H) 321.96.b	28,944,437			
87	Less: Regulatory Deferrals & Amortizations	(Note I) (Worksheet F, ln 4.C)	163,108			
88	Total O&M Allocable to Transmission	(lns 83 - 85 - 86 - 87)	20,099,885	TP	0.94388	18,971,827
89	Administrative and General	323.197.b (Note J)	115,581,644			
90	Less: Acct. 924, Property Insurance	323.185.b	4,470,216			
91	Acct. 9260039 PBOP Expense	PBOP Worksheet O Line 9 & 10, (Note K)	(3,118,949)			
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)	(276,641)			
94	Acct. 928, Reg. Com. Exp.	323.189.b	11,759,489			
95	Acct. 930.1, Gen. Advert. Exp.	323.191.b	167,607			
96	Acct. 930.2, Misc. Gen. Exp.	323.192.b	5,399,463			
97	Balance of A & G	(ln 89 - sum ln 90 to ln 96)	97,180,459	W/S	0.03675	3,571,441
98	Plus: Acct. 924, Property Insurance	(ln 90)	4,470,216	GP(h)	0.17740	793,000
99	Acct. 928 - Transmission Specific	Worksheet F ln 17.(E) (Note L)	-	TP	0.94308	-
100	Acct 930.1 - Only safety related ads -Direct	Worksheet F ln 32.(E) (Note L)	-	TP	0.94308	-
101	Acct 930.2 - Misc Gen. Exp. - Trans	Worksheet F ln 40.(E) (Note L)	190,764	DA	1.00000	190,764
102	Settlement Approved PBOP Recovery	PBOP Worksheet O, Col. C, Line 3, (Note M)	11,689,019	W/S	0.03675	429,579
103	A & G Subtotal	(sum lns 97 to 102)	113,530,458			4,984,784
104	O & M EXPENSE SUBTOTAL	(ln 88 + ln 103)	133,630,343			23,956,611
105	Plus: TEA Settlement in Account 565	Company Records (Note H)	-	DA	1.00000	-
106	Plus: Transmission Lease Payments To Affiliates in Acct 565 (Company Records) (Note H)		-	DA	1.00000	-
107	TOTAL O & M EXPENSE	(ln 104 + ln 105 + ln 106)	133,630,343			23,956,611
108	DEPRECIATION AND AMORTIZATION EXPENSE					
109	Production	336.2-6.f	90,976,769	NA	0.00000	-
110	Distribution	336.8.f	45,237,596	NA	0.00000	-
111	Transmission	336.7.f	20,181,719	TP1	0.96824	19,540,798
112	Plus: Transmission Plant-in-Service Additions (Worksheet I)		N/A			N/A
113	General	336.10.f	4,174,505	W/S	0.03675	153,416
114	Intangible	336.1.f	15,281,406	W/S	0.03675	561,601
115	TOTAL DEPRECIATION AND AMORTIZATI0N	(Ln 109+110+ 111+112+113+114)	175,851,995			20,255,814
116	TAXES OTHER THAN INCOME	(Note N)				
117	Labor Related					
118	Payroll	Worksheet H ln 22.(D)	13,919,677	W/S	0.03675	511,557
119	Plant Related					
120	Property	Worksheet H ln 22.(C) & ln 47.(C)	49,736,871	DA		9,415,795
121	Gross Receipts/Sales & Use	Worksheet H ln 22.(F)	16,607,423	NA	0.00000	-
122	Other	Worksheet H ln 22.(E)	1,875,199	GP(h)	0.17740	332,654
123	TOTAL OTHER TAXES	(sum lns 118 to 122)	82,139,170			10,260,005
124	INCOME TAXES	(Note O)				
125	T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =		39.00%			
126	EIT=(T/(1-T)) * (1-(WCLTD/WACC)) =		44.11%			
127	where WCLTD=(ln 162) and WACC = (ln 165)					
128	and FIT, SIT & p are as given in Note O.					
129	GRCF=1 / (1 - T) = (from ln 125)		1.6393			
130	Amortized Investment Tax Credit (enter negative)	(FF1 p.114, ln 19.c)	(4,930,858)			
131	Income Tax Calculation	(ln 126 * ln 134)	105,514,171			22,204,920
132	ITC adjustment	(ln 129 * ln 130)	(8,083,042)	NP(h)	0.19934	(1,611,277)
133	TOTAL INCOME TAXES	(sum lns 131 to 132)	97,431,128			20,593,644
134	RETURN ON RATE BASE (Rate Base*WACC)	(ln 78 * ln 165)	239,227,666			50,344,245
135	INTEREST ON IPP CONTRIBUTION FOR CONST. (Note F) (Worksheet D, ln 2.(B))		92,456	DA	1.00000	92,456
136	(Gains) / Losses on Sales of Plant Held for Future Use (Worksheet N, ln 4, Cols. ((F) & (H))		-			-
137	Tax Impact on Net Loss / (Gain) on Sales of Plant Held for Future Use (ln 136 * ln126)		-			-
138	TOTAL REVENUE REQUIREMENT (sum lns 107, 115, 123, 133, 134, 135)		728,372,758			125,502,776

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INDIANA MICHIGAN POWER COMPANY

SUPPORTING CALCULATIONS

ln No.								
	TRANSMISSION PLANT INCLUDED IN PJM TARIFF							
139	Total transmission plant	(ln 20)						1,299,347,603
140	Less transmission plant excluded from PJM Tariff (Note P)							-
141	Less transmission plant included in OATT Ancillary Services (Worksheet A, ln 23, Col. (C)) (Note Q)							72,922,777
142	Transmission plant included in PJM Tariff	(ln 139 - ln 140 - ln 141)						1,226,424,826
143	Percent of transmission plant in PJM Tariff	(ln 142 / ln 139)					**TP**	**0.94388**
				Payroll Billed from				
144	WAGES & SALARY ALLOCATOR (W/S)	(Note R)	Direct Payroll	AEP Service Corp.	Total			
145	Production	354.20.b	137,460,439	10,861,253	148,321,692	NA	0.00000	-
146	Transmission	354.21.b	3,961,979	3,299,449	7,261,428	TP	0.94388	6,853,898
147	Regional Market Expenses	354.22.b	0	0	-	NA	0.00000	-
148	Distribution	354.23.b	18,931,814	1,634,290	20,566,104	NA	0.00000	-
149	Other (Excludes A&G)	354.24,25,26.b	5,561,395	4,786,888	10,348,283	NA	0.00000	-
150	Total	(sum lns 145 to 149)	165,915,627	20,581,880	186,497,507			6,853,898
151	Transmission related amount						**W/S=**	**0.03675**

152	WEIGHTED AVERAGE COST OF CAPITAL (WACC)						$
153	Long Term Interest	(Worksheet M, ln. 21, col. (E))					97,348,540
154	Preferred Dividends	(Worksheet M, ln. 55, col. (E))					-
155	Development of Common Stock:						Average
156	Proprietary Capital	(Worksheet M, ln. 1, col. (E))					1,862,964,339
157	Less: Preferred Stock	(Worksheet M, ln. 2, col. (E))					-
158	Less: Account 216.1	(Worksheet M, ln. 3, col. (E))					(100,458)
159	Less: Account 219	(Worksheet M, ln. 4, col. (E))					(22,196,471)
160	Common Stock	(ln 156 - ln 157 - ln 158 - ln 159)					1,885,261,267
			Capital Structure Weighting		Cost		
161		Average $	Actual	Cap Limit	(Note S)		Weighted
162	Long Term Debt (Note T) W/S M, ln 11, ln 22, col. (E))	1,586,355,375	45.70%	0.00%	0.0614		0.0280
163	Preferred Stock (ln 157)	-	0.00%	0.00%	-		0.0000
164	Common Stock (ln 160)	1,885,261,267	54.30%	0.00%	11.49%		0.0624
165	Total (Sum lns 162 to 164)	3,471,616,642				**WACC=**	**0.0904**
166	Capital Structure Equity Limit (Note U)	100.0%					

AEP East Companies
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INDIANA MICHIGAN POWER COMPANY

Letter	Notes
	General Notes: a) References to data from Worksheets are indicated as: Worksheet X, Line#.Column.X
A	Revenue credits include: 1) Forfeited Discounts. 2) Miscellaneous Service Revenues. 3) Rental revenues earned on assets included in the rate base. 4) Revenues for associated business projects provided by employees whose labor and overhead costs are in the transmission cost of service. 5) Other electric revenues. 6) Revenues for grandfathered PTP contracts included in the load divisor. See Worksheet E for details.
B	The annual and monthly net plant carrying charges on page 1 are used to compute the revenue requirement for RTEP sponsored upgrades or those projects receiving approved incentive-ROE's.
C	Transmission Plant balances in this study reflect the average of the balances at December 31, 2012 and December 31, 2013.
D	The total-company balances shown for Accounts 281, 282, 283, 190 only reflect ADIT that relates to utility operations. The balance of Account 255 is reduced by prior flow throughs and is completely excluded if the utility chose to utilize amortization of tax credits against FIT expense. An exception to this is pre-1971 ITC balances, which are required to be taken as an offset to rate base. Account 281 is not allocated. In compliance with FERC Rulemaking RM02-7-000, Asset Retirement Obligation deferrals have been removed from ratebase. Transmission ADIT allocations are shown on WS B. The company will not include the ADIT portion of deferred hedge gains and losses in rate base.
E	Cash Working Capital assigned to transmission is one-eighth of O&M allocated to transmission, as shown on line 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.
G	Removes from the cost of service the Load Scheduling and Dispatch expenses booked to accounts 561.1 through 561.8. Expenses recorded in these accounts, with the exception of 561.4 & 561.8 (lines 15 & 16 above) are recovered in Schedule 1A, OATT ancillary services rates. See Worksheet F, lines 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.
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.
L	Expenses reported for these A&G accounts will be included in the cost of service only to the extent they are directly assignable to transmission service. Worksheet F allocates these expense items. Acct 928 Includes Regulatory Commission expenses itemized in FERC Form-1 at page 351, column H. FERC Assessment Fees and Annual Charges shall not be allocated to transmission. Only safety-related and educational advertising costs in Account 930.1 are included in the TCOS. Account 930.2 includes the expenses incurred by the transmission function for Associated Business Development revenues given as a credit to the TCOS on Worksheet E.
M	See note K above. Per the settlement in Docket ER08-1329, recoverable PBOP expense is based on an annual total for the operating companies that is ratioed to them based on the total of actual annual PBOP costs, including charges from the AEP Service Corportation. The calculation of the recoverable amount for each company is shown on Worksheet O, and the process for updating the annual total is documented on Attachment F, Allowable PBOP Expense Formula.
N	Includes only FICA, unemployment, highway, property and other assessments charged in the current year. Gross receipts, sales & use and taxes related to income are excluded.
O	The currently effective income tax rate, where FIT is the Federal income tax rate; SIT is the State income tax rate, and p = the percentage of federal income tax deductible for state income taxes. See Worksheet G for the development of the Company's composite SIT. A utility that elected to utilize amortization of tax credits against taxable income, rather than book tax credits to Account No. 255 and reduce rate base, must reduce its income tax expense by the amount of the Amortized Investment Tax Credit (Form 1, 266.8.f) (ln 130) multiplied by (1/1-T) . If the applicable tax rates are zero enter 0.

Inputs Required:	FIT =	35.00%	
	SIT=	6.15%	(State Income Tax Rate or Composite SIT. Worksheet G))
	p =	0.00%	(percent of federal income tax deductible for state purposes)

Letter	Notes
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. Interest expense for the true-up WACC is based on actual expenses for the true-up year. The amount of eligible hedging gains or losses included in total interest expense is limited to five basis points of the true-up capital structure. Details and calculations of the true-up weighted average cost of capital are shown on Worksheet M. Eligible Hedging Gains and Losses are defined in the Formula Protocols in the tariff. and on Worksheet M.
T	The Long Term Debt balance for I&M includes the accumulated balance of principle and related interest for Spent Nuclear Fuel Disposal Costs collected prior to April 7, 1983. This total balance of $265,249,280 at 12/31/12 is not included in the balance in line 162 above.
U	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 2013 FF1 Balances
Worksheet A Supporting Plant Balances
INDIANA MICHIGAN POWER COMPANY

Line Number	(A) Rate Base Item & Supporting Balance	(B) Source of Data	(C) Balance @ December 31, 2013	(D) Balance @ December 31, 2012	(E) Average Balance for 2013
	NOTE: Functional ARO investment and accumulated depreciation balances shown below are included in the total functional balances shown here.				
	Plant Investment Balances				
1	**Production Plant In Service**	FF1, page 205 Col.(g) & pg. 204 Col. (b), ln 46	4,218,917,902	4,037,746,725	4,128,332,314
2	**Production Asset Retirement Obligation (ARO)**	FF1, page 205&204, Col.(g)&(b), lns 15,24,34,44	310,217,009	303,665,963	306,941,486
3	**Transmission Plant In Service**	FF1, page 207 Col.(g) & pg. 206 Col. (b), ln 58	1,320,667,751	1,278,027,455	1,299,347,603
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	1,624,854,859	1,553,155,453	1,589,005,156
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	121,220,143	107,811,687	114,515,915
8	**General Asset Retirement Obligation**	FF1, page 207 Col.(g) & pg. 206 Col. (b), ln 98	172,921	172,922	172,922
9	**Intangible Plant In Service**	FF1, page 205 Col.(g) & pg. 204 Col. (b), ln 5	145,457,304	139,775,289	142,616,297
10	**Total Property Investment Balance**	(Sum of Lines: 3, 1, 5, 7, 9)	7,431,117,959	7,116,516,609	7,273,817,284
11	**Total ARO Balance (included in total on line 10)**	(Sum of Lines: 4, 2, 6, 8)	310,389,930	303,838,885	307,114,408
	Accumulated Depreciation & Amortization Balances				
12	**Production Accumulated Depreciation**	FF1, page 219, lns 20-24, Col. (b)	2,346,477,905	2,318,062,105	2,332,270,005
13	**Production ARO Accumulated Depreciation**	Company Records - Note 1	95,090,237	84,627,053	89,858,645
14	**Transmission Accumulated Depreciation**	FF1, page 219, ln 25, Col. (b)	551,316,240	537,188,312	544,252,276
15	**Transmission ARO Accumulated Depreciation**	Company Records - Note 1	-	-	-
16	**Distribution Accumulated Depreciation**	FF1, page 219, ln 26, Col. (b)	499,120,014	479,335,470	489,227,742
17	**Distribution ARO Accumulated Depreciation**	Company Records - Note 1	-	-	-
18	**General Accumulated Depreciation**	FF1, page 219, ln 28, Col. (b)	28,844,430	27,301,514	28,072,972
19	**General ARO Accumulated Depreciation**	Company Records - Note 1	144,557	138,294	141,425
20	**Intangible Accumulated Amortization**	FF1, page 200, ln 21, Col. (b)	141,524,886	132,615,751	137,070,319
21	**Total Accumulated Depreciation or Amortization**	(Sum of Lines: 14, 12, 16, 18, 20)	3,567,283,475	3,494,503,152	3,530,893,314
22	**Total ARO Balance (included in total on line 21)**	(Sum of Lines: 15, 13, 17, 19)	95,234,793	84,765,347	90,000,070
	Generation Step-Up Units				
23	**GSU Investment Amount**	Company Records - Note 1	75,169,412	70,676,141	72,922,777
24	**GSU Accumulated Depreciation**	Company Records - Note 1	18,172,841	16,395,356	17,284,099
25	**GSU Net Balance**	(Line 23 - Line 24)	56,996,571	54,280,785	55,638,678
	Transmission Accumulated Depreciation Net of GSU Accumulated Depreciation				
26	**Transmission Accumulated Depreciation**	(Line 14 Above)	551,316,240	537,188,312	544,252,276
27	**Less: GSU Accumulated Depreciation**	(Line 24 Above)	18,172,841	16,395,356	17,284,099
28	**Subtotal of Transmission Net of GSU**	(Line 26 - Line 27)	533,143,399	520,792,956	526,968,177
	Plant Held For Future Use				
29	**Plant Held For Future Use**	FF1, page 214, ln 47, Col. (d)	5,651,068	6,294,968	5,973,018
30	**Transmission Plant Held For Future**	Company Records - Note 1	208,360	208,360	208,360
	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 unamortized balance of hedging gains or losses.

AEP East Companies
Cost of Service Formula Rate Using 2013 FF1 Balances
Worksheet B Supporting ADIT and ITC Balances
INDIANA MICHIGAN POWER COMPANY

	(A)	(B)	(C)	(D)	(E)
Line Number	Description	Source	Balance @ December 31, 2013	Balance @ December 31, 2012	Average Balance for 2013
1	**Account 281**				
2	Year End Utility Deferrals	FF1, p. 272 - 273, ln 8, Col. (k)	215,395	246,285	230,840
3	Less: ARO Related Deferrals	Company Records - Note 1	-	-	-
4	Less: Other Excluded Deferrals	Company Records - Note 1	215,395	246,285	230,840
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)	999,904,930	920,003,284	959,954,107
8	Less: ARO Related Deferrals	Company Records - Note 1	77,712,096	79,547,117	78,629,607
9	Less: Other Excluded Deferrals	Company Records - Note 1	760,497,113	689,050,574	724,773,844
10	Transmission Related Deferrals	Ln 7 - ln 8 - ln 9	161,695,721	151,405,593	156,550,657
11	**Account 283**				
12	Year End Utility Deferrals	FF1, p. 276 - 277, ln 9, Col. (k)	724,474,181	664,464,895	694,469,538
13	Less: ARO Related Deferrals	Company Records - Note 1	568,535,317	489,889,606	529,212,462
14	Less: Other Excluded Deferrals	Company Records - Note 1	144,205,379	165,150,767	154,678,073
15	Transmission Related Deferrals	Ln 12 - ln 13 - ln 14	11,733,485	9,424,522	10,579,004
16	**Account 190**				
17	Year End Utility Deferrals	FF1, p. 234, ln 8, Col. (c)	759,447,349	755,767,692	757,607,521
18	Less: ARO Related Deferrals	Company Records - Note 1	648,303,915	569,810,510	609,057,213
19	Less: Other Excluded Deferrals	Company Records - Note 1	98,475,324	170,908,769	134,692,047
20	Transmission Related Deferrals	Ln 17 - ln 18 - ln 19	12,668,110	15,048,413	13,858,262
21	**Account 255**				
22	Year End ITC Balances	FF1, p. 266-267, ln 8, Col. (h)	43,199,590	48,130,448	45,665,019
23	Less: Balances Not Qualified for Ratebase	Company Records - Note 1	43,199,590	48,130,448	45,665,019
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 2013 FF1 Balances
Worksheet C Supporting Working Capital Rate Base Adjustments
INDIANA MICHIGAN POWER COMPANY

Materials & Supplies

(A) Line Number	(B)	(C) Source	(D) Balance @ December 31, 2013	(E) Balance @ December 31, 2012	(F) Average Balance for 2013
1					
2	Transmission Materials & Supplies	FF1, p. 227, ln 8, Col. (c) & (b)	1,405,516	1,954,137	1,679,827
3	General Materials & Supplies	FF1, p. 227, ln 11, Col. (c) & (b)	60,747	52,111	56,429
4	Stores Expense (Undistributed)	FF1, p. 227, ln 16, Col. (c) & (b)	0	0	-

Prepayment Balance Summary

Line		(C) Average of YE Balance	(D) Excludable Balances	(E) 100% Transmission Related	(F) Transmission Plant Related	(G) Transmission Labor Related	(H) Total Included in Ratebase (E)+(F)+(G)
5							
6	Totals as of December 31, 2013	7,334,644	(119,889,006)	0	4,363,899	122,859,751	127,223,650
7	Totals as of December 31, 2012	10,850,234	(139,407,819)		5,571,844	144,686,210	150,258,054
8	**Average Balance**	9,092,439	(129,648,413)	-	4,967,872	133,772,981	138,740,852

Prepayments Account 165 - Balance @ 12/31/2013

9	Acc. No.	Description	2013 YE Balance	Excludable Balances	100% Transmission Related	Transmission Plant Related	Transmission Labor Related	Total Included in Ratebase (E)+(F)+(G)	Explanation
10	1650001	Prepaid Insurance	2,700,766	-		2,700,766		2,700,766	Plant Related Insurance Policies
11	165000213	Prepaid Taxes	432,563	432,563				-	Prepaid Taxes-Distribution
12	1650003	Prepaid Rents	(2,676)	(2,676)				-	River Transport
13	1650005	Prepaid Employee Benefits	0	-				-	Benefits Generation
14	1650006	Other Prepayments	1,093,543	1,093,543				-	Relates to EPRI dues
15	1650009	Prepaid Carry Cost-Factored AR	73,021	73,021				-	AR Factoring - Retail Only
16	1650010	Prepaid Pension Benefits	122,859,751				122,859,751	122,859,751	Prefunded Pension Expense
17	1650014	FAS 158 Qual Contra Asset	(122,859,751)	(122,859,751)				-	SFAS 158 Offset
18	165001113	Prepaid Sales Taxes	684,965	684,965			-	-	Prepaid Sales Tax - Distribution
19	165001213	Prepaid Use Taxes	513,909	513,909			-	-	Prepaid Use Tax - Distribution
20	1650021	Prepaid Insurance - EIS	1,663,133	-		1,663,133		1,663,133	Energy INS Services
21	1650022	Prepaid SNF Container Costs	0	-			-	-	
22	1650023	Prepaid Lease	175,420	175,420			-	-	Prepaid Leases
23	1650026	Prepaid SNF Costs	0	-					
		Subtotal - Form 1, p 111.57.c	7,334,644	(119,889,006)	0	4,363,899	122,859,751	127,223,650	

Prepayments Account 165 - Balance @ 12/31/ 2012

24	Acc. No.	Description	2012 YE Balance	Excludable Balances	100% Transmission Related	Transmission Plant Related	Transmission Labor Related	Total Included in Ratebase (E)+(F)+(G)	Explanation
25	1650001	Prepaid Insurance	3,887,518	-		3,887,518		3,887,518	Plant Related Insurance Policies
26	165000212	Prepaid Taxes	436,231	436,231				-	Prepaid Taxes
27	1650003	Prepaid Rents	3,369	3,369			-	-	River Transport
28	1650005	Prepaid Employee Benefits	1,569	1,569			-	-	Benefits Generation
29	1650006	Other Prepayments	3,909,935	3,909,935				-	Relates to EPRI dues
30	1650009	Prepaid Carry Cost-Factored AR	47,917	47,917				-	AR Factoring - Retail Only
31	1650010	Prepaid Pension Benefits	144,686,210				144,686,210	144,686,210	Prefunded Pension Expense
32	1650014	FAS 158 Qual Contra Asset	(144,686,210)	(144,686,210)				-	SFAS 158 Offset
33	165001112	Prepaid Sales Taxes	600,600	600,600			-	-	Prepaid Sales Tax - Distribution
34	165001212	Prepaid Use Taxes	139,157	139,157			-	-	Prepaid Use Tax - Distribution
35	1650021	Prepaid Insurance - EIS	1,684,326	-		1,684,326		1,684,326	Energy INS Services
36	1650022	Prepaid SNF Container Costs	0	-			-	-	
37	1650023	Prepaid Lease	139,613	139,613			-	-	Prepaid Leases
38	1650026	Prepaid SNF Costs	0	-					
		Subtotal - Form 1, p 111.57.d	10,850,234	(139,407,819)		5,571,844	144,686,210	150,258,054	

AEP East Companies
Cost of Service Formula Rate Using 2013 FF1 Balances
Worksheet D Supporting IPP Credits
INDIANA MICHIGAN POWER COMPANY

Line Number	(A) Description	(B) 2013
1	Net Funds from IPP Customers 12/31/2012 (2013 FORM 1, P269, line 6.b)	(2,810,348)
2	Interest Accrual (Company Records - Note 1)	(92,456)
3	Revenue Credits to Generators (Company Records - Note 1)	-
4	Other Adjustments	
5	Accounting Adjustment (Company Records - Note 1)	-
6		-
7	Net Funds from IPP Customers 12/31/2013 (2013 FORM 1, P269, line 6.f)	(2,902,804)
8	Average Balance for Year as Indicated in Column B ((ln 1 + ln 7)/2)	(2,856,576)

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

AEP East Companies
Cost of Service Formula Rate Using 2013 FF1 Balances
Worksheet E Supporting Revenue Credits
INDIANA MICHIGAN POWER COMPANY

Line Number	Description	Total Company	Non-Transmission	Transmission
1	**Account 450, Forfeited Discounts (FF1 p.300.16.(b); Company Records - Note 1)**	4,751,060	4,751,060	-
2	**Account 451,Miscellaneous Service Revenues (FF1 p.300.17.(b); Company Records - Note 1)**	3,891,482	3,834,695	56,787
3	**Account 454, Rent from Electric Property (FF1 p.300.19.(b); Company Records - Note 1)**	6,512,406	6,172,981	339,425
4	**Account 4560015, Associated Business Development - (Company Records - Note 1)**	1,801,980	1,382,655	419,325
5	**Account 456 - Other Electric Revenues - (Company Records - Note 1)**	39,128,253	38,667,316	460,937
6	**Subtotal - Other Operating Revenues (Company Total equals (FF1 p. 300.26.(b))**	56,085,181	54,808,707	1,276,474
7	**Accounts 4470004 & 5, Revenues from Grandfathered Transmission Contracts - (Company Records - Note 1)**	-	-	-
8	**Total Other Operating Revenues To Reduce Revenue Requirement**	56,085,181	54,808,707	1,276,474

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 2013 FF1 Balances
Worksheet F Supporting Allocation of Specific O&M or A&G Expenses
INDIANA MICHIGAN POWER COMPANY

Line Number	(A) Item No.	(B) Description	(C) 2013 Expense	(D) 100% Non-Transmission	(E) 100% Transmission Specific	(F) Explanation
		Regulatory O&M Deferrals & Amortizations				
1	5660000	Misc Transmission Expense	163,108			
2		**Total**	163,108			
		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	29,851			
5	FF1 p 321.86.b	561.2 - Load Dispatch - Monitor & Operate Trans System	1,451,031			
6	FF1 p 321.87.b	561.3 - Load Dispatch - Trans Service & Scheduling	0			
7	FF1 p 321.88.b	561.4 - Scheduling, System Control & Dispatch	3,174,683			
8	FF1 p 321.89.b	561.5 - Reliability, Planning and Standards Development	390,782			
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	746,285			
12		**Total of Account 561**	5,792,632			
		Account 928				
13	9280000	Regulatory Commission Exp	121,817	121,817	-	
14	9280001	Regulatory Commission Exp-Adm	11,554,774	11,554,774	-	
15	9280002	Regulatory Commission Exp-Case	82,899	82,899	-	
16	9280003	Rate Case Amortization	-	-		
17		**Total**	11,759,490	11,759,490	-	
		Account 930.1				
18	9301000	General Advertising Expenses	11,292	11,292	-	
19	9301001	Newspaper Advertising Space	25,937	25,937	-	
20	9301002	Radio Station Advertising Time	33,690	33,690	-	
21	9301003	TV Station Advertising Time	2,590	2,590	-	
22	9301006	Spec Corporate Comm Info Proj	14,768	14,768	-	
23	9301007	Special Adv Space & Prod Exp	-	-	-	
24	9301008	Direct Mail and Handouts	-	-	-	
25	9301009	Fairs, Shows, and Exhibits	85	85	-	
26	9301010	Publicity	7,591	7,591	-	
27	9301011	Dedications, Tours, & Openings	-	-	-	
28	9301012	Public Opinion Surveys	14,866	14,866	-	
29	9301013	Movies Slide Films & Speeches	-	-	-	
30	9301014	Video Communications	33	33	-	
31	9301015	Other Corporate Comm Exp	56,756	56,756	-	
32		**Total**	167,608	167,608	-	
		Account 930.2				
33	9302000	Misc General Expenses	3,439,651	3,439,651		
34	9302003	Corporate & Fiscal Expenses	182,406	182,406		
35	9302004	Research, Develop&Demonstr Exp	7,900	7,900		
36	9302005	Nucl Fac Ins - Replce Engy Cst	926,026	926,026		
37	9302006	Assoc Business Development Materials Sold	51,990	51,990	0	
38	9302007	Assoc Business Development Exp	791,475	600,711	190,764	
39	9302458	AEPSC nonaffiliated expense	16	16		
40		**Total**	5,399,464	5,208,700	190,764	

AEP East Companies
Cost of Service Formula Rate Using 2013 FF1 Balances
Worksheet G Supporting - Development of Composite State Income Tax Rate
INDIANA MICHIGAN POWER COMPANY

Indiana Corporate Income Tax Rate	7.75%	
Apportionment Factor - Note 2	60.74%	
Effective State Tax Rate		4.71%
Michigan Single Business Tax Rate	6.00%	
Apportionment Factor - Note 2	15.65%	
Effective State Tax Rate		0.94%
West Virginia Corporation Income Tax Rate	7.00%	
Apportionment Factor - Note 2	3.07%	
Effective State Tax Rate		0.21%
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%
Kentucky Corporation Income Tax Rate	6.00%	
Apportionment Factor - Note 2	2.41%	
Effective State Tax Rate		0.14%
Missouri Corporation Income Tax Rate	6.25%	
Apportionment Factor - Note 2	0.00%	
Effective State Tax Rate		0.00%
Illinois Corporation Income Tax Rate	9.50%	
Apportionment Factor - Note 2	1.63%	
Effective State Tax Rate		0.15%
Total Effective State Income Tax Rate		6.15%

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 2013 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	Revenue Taxes					
2	Gross Receipts Tax	16,462,764				16,462,764
3	Real Estate and Personal Property Taxes					
4	Real and Personal Property - Michigan	30,734,166	30,734,166			
5	Real and Personal Property - Indiana	18,991,227	18,991,227			
6	Real and Personal Property - Other Jurisdictions	11,478	11,478			
7	Payroll Taxes					
8	Federal Insurance Contribution (FICA)	12,737,766		12,737,766		
9	Federal Unemployment Tax	253,590		253,590		
10	State Unemployment Insurance	928,321		928,321		
11	Production Taxes					
12	State Severance Taxes	-				-
13	Miscellaneous Taxes					
14	State Business & Occupation Tax	-				-
15	State Public Service Commission Fees	1,890,825			1,890,825	
16	State Franchise Taxes	(17,203)			(17,203)	
17	State Lic/Registration Fee	1,577			1,577	
18	Misc. State and Local Tax	-			-	
19	Sales & Use	132,213				132,213
20	Federal Excise Tax	12,446				12,446
21	Michigan Single Business Tax	-				-
22	Total Taxes by Allocable Basis	82,139,170	49,736,871	13,919,677	1,875,199	16,607,423
	(Total Company Amount Ties to FFI p.114, Ln 14,(c))					
	NOTE 1: The detail of each total company number and its source in the FERC Form 1 is shown on WS H-1.					

Functional Property Tax Allocation

Line No.		Production	Transmsission	Distribution	General	Total
23	Functionalized Net Plant (Hist. TCOS, Lns 212 thru 222)	1,657,313,225	769,351,511	1,125,734,845	92,347,349	3,644,746,929
	MICHIGAN JURISDICTION					
24	Percentage of Plant in MICHIGAN JURISDICTION	64.94%	15.84%	19.68%	15.57%	
25	Net Plant in MICHIGAN JURISDICTION (Ln 23 * Ln 24)	1,076,259,208	121,865,279	221,544,617	14,378,482	1,434,047,587
26	Less: Net Value of Exempted Generation Plant	289,185,970				
27	Taxable Property Basis (Ln 25 - Ln 26)	787,073,238	121,865,279	221,544,617	14,378,482	1,144,861,617
28	Relative Valuation Factor	100%	100%	100%	100%	
29	Weighted Net Plant (Ln 27 * Ln 28)	787,073,238	121,865,279	221,544,617	14,378,482	
30	General Plant Allocator (Ln 29 / (Total - General Plant))	69.62%	10.78%	19.60%	-100.00%	
31	Functionalized General Plant (Ln 30 * General Plant)	10,010,692	1,549,990	2,817,800	(14,378,482)	-
32	Weighted MICHIGAN JURISDICTION Plant (Ln 29 + 31)	797,083,930	123,415,270	224,362,417	0	1,144,861,617
33	Functional Percentage (Ln 32/Total Ln 32)	69.62%	10.78%	19.60%		
34	Functionalized Expense in MICHIGAN JURISDICTION	21,397,966	3,313,121	6,023,079		30,734,166
	INDIANA JURISDICTION					
35	Percentage of Plant in INDIANA JURISDICTION	35.06%	84.16%	80.32%	84.43%	
36	Net Plant in INDIANA JURISDICTION (Ln 23 * Ln 35)	581,054,017	647,486,232	904,190,228	77,968,866	2,210,699,342
37	Less: Net Value of Exempted Generation Plant	117,040,647				
38	Taxable Property Basis (Ln 36 - Ln 37)	464,013,370	647,486,232	904,190,228	77,968,866	2,093,658,695
39	Relative Valuation Factor	100%	100%	100%	100%	
40	Weighted Net Plant (Ln 38 * Ln 39)	464,013,370	647,486,232	904,190,228	77,968,866	
41	General Plant Allocator (Ln 40 / (Total - General Plant))	23.02%	32.12%	44.86%	-100.00%	
42	Functionalized General Plant (Ln 41 * General Plant)	17,948,494	25,045,405	34,974,968	(77,968,866)	-
43	Weighted INDIANA JURISDICTION Plant (Ln 40 + 42)	481,961,864	672,531,636	939,165,196	0	2,093,658,695
44	Functional Percentage (Ln 43/Total Ln 43)	23.02%	32.12%	44.86%		
45	Functionalized Expense in INDIANA JURISDICTION	4,371,795	6,100,422	8,519,010		18,991,227
46	Total Other Jurisdictions: (Line 6 * Net Plant Allocator)		2,252			11,478
47	Total Func. Property Taxes (Sum Lns 34, 45 46)	25,769,761	9,415,795	14,542,089		49,736,871

AEP East Companies
Cost of Service Formula Rate Using 2013 FF1 Balances
Worksheet H-1 Form 1 Source Reference of Company Amounts on WS H
INDIANA MICHIGAN 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			
2	Gross Receipts Tax	16,462,764		
			(31,995)	P.263 ln 14 (i)
			16,279,000	P.263 ln 15 (i)
			(103,256)	P.263.2 ln 24 (i)
			179,154	P.263.2 ln 25 (i)
			(99,464)	P.263.2 ln 26 (i)
			239,325	P.263.2 ln 38 (i)
3	Real Estate and Personal Property Taxes			
4	Real and Personal Property - Michigan	30,734,166		
			48,981	P.263.1 ln 19 (i)
			30,435,644	P.263.1 ln 20 (i)
			(3,511)	P.263.1 ln 23 (i)
			40,809	P.263.1 ln 24 (i)
			3,243	P.263.1 ln 27 (i)
			209,000	P.263.1 ln 28 (i)
5	Real and Personal Property - Indiana	18,991,227		
			(6,011)	P.263 ln 24 (i)
			1,976	P.263 ln 25 (i)
			(204,676)	P.263 ln 26 (i)
			3,377,689	P.263 ln 27 (i)
			15,587,580	P.263 ln 28 (i)
			8,499	P.263 ln 30 (i)
			226,170	P.263 ln 31 (i)
6	Real and Personal Property - Other Jurisdictions	11,478		
			3,393	P.263.2 ln 9 (i)
			3,385	P.263.2 ln 10 (i)
			1,622	P.263.3 ln 3 (i)
			3,078	P.263.3 ln 4 (i)
7	Payroll Taxes			
8	Federal Insurance Contribution (FICA)	12,737,766		
			12,737,766	P.263 ln 3 (i)
9	Federal Unemployment Tax	253,590		
			253,590	P.263 ln 4 (i)
10	State Unemployment Insurance	928,321		
			237,544	P.263 ln 13 (i)
			700,011	P.263.1 ln 11 (i)
			(9,234)	P.263.2 ln 18 (i)
11	Production Taxes			
12	State Severance Taxes	-		
13	Misc States - 2010		-	P.263.2 ln 32 (i)
14	Misc States 2012		-	P.263.2 ln 33 (i)
15	Miscellaneous Taxes			
16	State Business & Occupation Tax	-		
			-	
17	State Public Service Commission Fees	1,890,825		
			635,491	P.263 ln 21 (i)
			703,152	P.263 ln 22 (i)
			384,657	P.263.1 ln 12 (i)
			167,525	P.263.1 ln 13 (i)
18	State Franchise Taxes	(17,203)		
			(77,486)	P.263.2 ln 6(i)
			60,283	P.263.2 ln 7(i)
19	State Lic/Registration Fee	1,577		
			22	P.263 ln 17 (i)
			1,250	P.263.1 ln 31 (i)
			50	P.263.2 ln 2 (i)
			100	P.263.3 ln 24 (i)
			155	P.263.3 ln 25 (i)
			-	
20	Misc. State and Local Tax	-		
			-	
21	Sales & Use	132,213		
			12,602	P.263.1 ln 14 (i)
			119,611	P.263.1 ln 15 (i)
22	Federal Excise Tax	12,446		
			12,446	P.263 ln 6 (i)
			-	
23	Michigan Single Business Tax	-		
			-	P.263.1 ln 5 (i)
24	Total Taxes by Allocable Basis (Total Company Amount Ties to FFI p.114, Ln 14,(c))	82,139,170	82,139,170	

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 2013 FF1 Balances
Worksheet I Supporting Transmission Plant in Service Additions
INDIANA MICHIGAN POWER COMPANY

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

I. Calculation of Composite Depreciation Rate

1	Transmission Plant @ Beginning of Historic Period (2013) (P.206, ln 58,(b)):	1,278,027,455
2	Transmission Plant @ End of Historic Period (2013) (P.207, ln 58,(g)):	1,320,667,751
3		2,598,695,206
4	Average Balance of Transmission Investment	1,299,347,603
5	Annual Depreciation Expense, Historic TCOS, ln 276	20,181,719
6	Composite Depreciation Rate	1.55%
7	Round to 1.55% to Reflect a Composite Life of 65 Years	1.55%

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

8	Month in Service	Capitalized Balance	Composite Annual Depreciation Rate	Annual Depreciation	Monthly Depreciation	No. Months Depreciation	First Year Depreciation Expense
9	January	$ 5,937,496	1.55%	$ 92,031	$ 7,669	11	$ 84,359
10	February	$ 6,695,442	1.55%	$ 103,779	$ 8,648	10	$ 86,480
11	March	$ 1,972,387	1.55%	$ 30,572	$ 2,548	9	$ 22,932
12	April	$ 1,591,367	1.55%	$ 24,666	$ 2,056	8	$ 16,448
13	May	$ 15,162,353	1.55%	$ 235,016	$ 19,585	7	$ 137,095
14	June	$ 2,073,068	1.55%	$ 32,133	$ 2,678	6	$ 16,068
15	July	$ 1,637,405	1.55%	$ 25,380	$ 2,115	5	$ 10,575
16	August	$ 1,688,786	1.55%	$ 26,176	$ 2,181	4	$ 8,724
17	September	$ 1,914,030	1.55%	$ 29,667	$ 2,472	3	$ 7,416
18	October	$ 1,955,187	1.55%	$ 30,305	$ 2,525	2	$ 5,050
19	November	$ 1,949,755	1.55%	$ 30,221	$ 2,518	1	$ 2,518
20	December	$ 26,363,042	1.55%	$ 408,627	$ 34,052	0	$ -
21	Investment	$ 68,940,318				Depreciation Expense	$ 397,665

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 2014

		Estimated Cost (000's)	Month in Service
25	**Major Zonal Projects**		
26	2013 Asset Replacement Program	$6,913	Various
27	Sorenson 765/345 kV Project	$7,192	Dec-14
28	I&M SCADA Upgrade	$6,451	Various
29	Rockport Improvements	$10,865	May-14
30	Subtotal	$31,421	
31	**PJM Socialized/Beneficiary Allocated Regional Projects**		
32		$0	
33	Subtotal	$0	

AEP East Companies
Cost of Service Formula Rate Using 2013 FF1 Balances
Worksheet J Supporting Calculation of PROJECTED PJM RTEP Project Revenue Requirement Billed to Benefiting Zones
INDIANA MICHIGAN 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, ln 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 equity percentage is from the Projected TCOS, lns 162 through164)

	%	Cost		Weighted cost
Long Term Debt	45.23%	5.73%		2.592%
Preferred Stock	0.00%	0.00%		0.000%
Common Stock	54.77%	11.49%		6.293%
			R =	8.885%

SUMMARY OF PROJECTED ANNUAL RTEP REVENUE REQUIREMENTS		Rev Require	W Incentives	Incentive Amounts
PROJECTED YEAR	2014	4,959,187	4,959,187	$ -

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

Rate Base (Projected TCOS, ln 78)	609,724,413
R (from A. above)	8.885%
Return (Rate Base x R)	54,176,395

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

Return (from B. above)	54,176,395
Effective Tax Rate (Projected TCOS, ln 126)	45.28%
Income Tax Calculation (Return x CIT)	24,528,993
ITC Adjustment	(1,585,936)
Income Taxes	22,943,057

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

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

Annual Revenue Requirement (Projected TCOS, ln 1)	132,030,251
T.E.A. & Lease Payments (Projected TCOS, Lns 105 & 106)	-
Return (Projected TCOS, ln 134)	54,176,395
Income Taxes (Projected TCOS, ln 133)	22,943,057
Annual Revenue Requirement, Less TEA Charges, Return and Taxes	54,910,799

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

Annual Revenue Requirement, Less TEA Charges, Return and Taxes	54,910,799
Return (from I.B. above)	54,176,395
Income Taxes (from I.C. above)	22,943,057
Annual Revenue Requirement, with Basis Point ROE increase	132,030,251
Depreciation (Projected TCOS, ln 111)	19,516,476
Annual Rev. Req, w/ Basis Point ROE increase, less Depreciation	112,513,774

C. Determine FCR with hypothetical basis point ROE increase.

Net Transmission Plant (Projected TCOS, ln 48)	712,354,940
Annual Revenue Requirement, with Basis Point ROE increase	132,030,251
FCR with Basis Point increase in ROE	18.53%
Annual Rev. Req, w / Basis Point ROE increase, less Dep.	112,513,774
FCR with Basis Point ROE increase, less Depreciation	15.79%
FCR less Depreciation (Projected TCOS, ln 9)	14.73%
Incremental FCR with Basis Point ROE increase, less Depreciation	1.07%

III. Calculation of Composite Depreciation Rate

Transmission Plant @ Beginning of Historic Period (2013) (P.206, ln 58,(b)):	1,278,027,455
Transmission Plant @ End of Historic Period (2013) (P.207, ln 58,(g)):	1,320,667,751
Subtotal	2,598,695,206
Average Transmission Plant Balance for 2013	1,299,347,603
Annual Depreciation Rate (Projected TCOS, ln 111)	20,181,719
Composite Depreciation Rate	1.55%
Depreciable Life for Composite Depreciation Rate	64.38
Round to nearest whole year	64

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

Current Projected Year ARR	**1,249,385**
Current Projected Year ARR w/ Incentive	**1,249,385**
Current Projected Year Incentive ARR	**-**

Details

Investment	8,316,811	Current Year	**2014**
Service Year (yyyy)	2009	ROE increase accepted by FERC (Basis Points)	-
Service Month (1-12)	6	FCR w/o incentives, less depreciation	14.73%
Useful life	64	FCR w/incentives approved for these facilities, less dep.	14.73%
CIAC (Yes or No)	No	Annual Depreciation Expense	129,950

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.

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 **		
2009	8,316,811	64,975	8,251,836	1,280,088	1,280,088	$ -					
2010	8,251,836	129,950	8,121,886	1,325,927	1,325,927	$ -	$ 1,408,114		$ 1,408,114		
2011	8,121,886	129,950	7,991,936	1,306,791	1,306,791	$ -	$ 1,487,355		$ 1,487,355		
2012	7,991,936	129,950	7,861,985	1,287,656	1,287,656	$ -	$ 1,319,695		$ 1,319,695		
2013	7,861,985	129,950	7,732,035	1,268,520	1,268,520	$ -	$ 1,272,484		$ 1,272,484		
2014	7,732,035	129,950	7,602,085	1,249,385	1,249,385	$ -					
2015	7,602,085	129,950	7,472,135	1,230,249	1,230,249	$ -					
2016	7,472,135	129,950	7,342,185	1,211,113	1,211,113	$ -					
2017	7,342,185	129,950	7,212,235	1,191,978	1,191,978	$ -					
2018	7,212,235	129,950	7,082,284	1,172,842	1,172,842	$ -					
2019	7,082,284	129,950	6,952,334	1,153,706	1,153,706	$ -					
2020	6,952,334	129,950	6,822,384	1,134,571	1,134,571	$ -					
2021	6,822,384	129,950	6,692,434	1,115,435	1,115,435	$ -					
2022	6,692,434	129,950	6,562,484	1,096,300	1,096,300	$ -					
2023	6,562,484	129,950	6,432,534	1,077,164	1,077,164	$ -					
2024	6,432,534	129,950	6,302,583	1,058,028	1,058,028	$ -					
2025	6,302,583	129,950	6,172,633	1,038,893	1,038,893	$ -					
2026	6,172,633	129,950	6,042,683	1,019,757	1,019,757	$ -					
2027	6,042,683	129,950	5,912,733	1,000,621	1,000,621	$ -					
2028	5,912,733	129,950	5,782,783	981,486	981,486	$ -					
2029	5,782,783	129,950	5,652,832	962,350	962,350	$ -					
2030	5,652,832	129,950	5,522,882	943,214	943,214	$ -					
2031	5,522,882	129,950	5,392,932	924,079	924,079	$ -					
2032	5,392,932	129,950	5,262,982	904,943	904,943	$ -					
2033	5,262,982	129,950	5,133,032	885,808	885,808	$ -					
2034	5,133,032	129,950	5,003,082	866,672	866,672	$ -					
2035	5,003,082	129,950	4,873,131	847,536	847,536	$ -					
2036	4,873,131	129,950	4,743,181	828,401	828,401	$ -					
2037	4,743,181	129,950	4,613,231	809,265	809,265	$ -					
2038	4,613,231	129,950	4,483,281	790,129	790,129	$ -					
2039	4,483,281	129,950	4,353,331	770,994	770,994	$ -					
2040	4,353,331	129,950	4,223,381	751,858	751,858	$ -					
2041	4,223,381	129,950	4,093,430	732,723	732,723	$ -					
2042	4,093,430	129,950	3,963,480	713,587	713,587	$ -					
2043	3,963,480	129,950	3,833,530	694,451	694,451	$ -					
2044	3,833,530	129,950	3,703,580	675,316	675,316	$ -					
2045	3,703,580	129,950	3,573,630	656,180	656,180	$ -					
2046	3,573,630	129,950	3,443,680	637,044	637,044	$ -					
2047	3,443,680	129,950	3,313,729	617,909	617,909	$ -					
2048	3,313,729	129,950	3,183,779	598,773	598,773	$ -					
2049	3,183,779	129,950	3,053,829	579,637	579,637	$ -					
2050	3,053,829	129,950	2,923,879	560,502	560,502	$ -					
2051	2,923,879	129,950	2,793,929	541,366	541,366	$ -					
2052	2,793,929	129,950	2,663,979	522,231	522,231	$ -					
2053	2,663,979	129,950	2,534,028	503,095	503,095	$ -					
2054	2,534,028	129,950	2,404,078	483,959	483,959	$ -					
2055	2,404,078	129,950	2,274,128	464,824	464,824	$ -					
2056	2,274,128	129,950	2,144,178	445,688	445,688	$ -					
2057	2,144,178	129,950	2,014,228	426,552	426,552	$ -					
2058	2,014,228	129,950	1,884,277	407,417	407,417	$ -					
2059	1,884,277	129,950	1,754,327	388,281	388,281	$ -					
2060	1,754,327	129,950	1,624,377	369,146	369,146	$ -					
2061	1,624,377	129,950	1,494,427	350,010	350,010	$ -					
2062	1,494,427	129,950	1,364,477	330,874	330,874	$ -					
2063	1,364,477	129,950	1,234,527	311,739	311,739	$ -					
2064	1,234,527	129,950	1,104,576	292,603	292,603	$ -					
2065	1,104,576	129,950	974,626	273,467	273,467	$ -					
2066	974,626	129,950	844,676	254,332	254,332	$ -					
2067	844,676	129,950	714,726	235,196	235,196	$ -					
2068	714,726	129,950	584,776	216,061	216,061	$ -					
Project Totals		7,732,035		46,768,721	46,768,721	-					

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

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

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

I & 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	**87,393**
Current Projected Year ARR w/ Incentive	**87,393**
Current Projected Year Incentive ARR	**-**

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)**

Details			
Investment	548,167	Current Year	2014
Service Year (yyyy)	2013	ROE increase accepted by FERC (Basis Points)	-
Service Month (1-12)	6	FCR w/o incentives, less depreciation	14.73%
Useful life	64	FCR w/incentives approved for these facilities, less dep.	14.73%
CIAC (Yes or No)	No	Annual Depreciation Expense	8,565

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	548,167	4,283	543,884	84,371	84,371	$ -
2014	543,884	8,565	535,319	87,393	87,393	$ -
2015	535,319	8,565	526,754	86,132	86,132	$ -
2016	526,754	8,565	518,189	84,870	84,870	$ -
2017	518,189	8,565	509,624	83,609	83,609	$ -
2018	509,624	8,565	501,059	82,348	82,348	$ -
2019	501,059	8,565	492,494	81,087	81,087	$ -
2020	492,494	8,565	483,929	79,825	79,825	$ -
2021	483,929	8,565	475,364	78,564	78,564	$ -
2022	475,364	8,565	466,798	77,303	77,303	$ -
2023	466,798	8,565	458,233	76,042	76,042	$ -
2024	458,233	8,565	449,668	74,780	74,780	$ -
2025	449,668	8,565	441,103	73,519	73,519	$ -
2026	441,103	8,565	432,538	72,258	72,258	$ -
2027	432,538	8,565	423,973	70,997	70,997	$ -
2028	423,973	8,565	415,408	69,735	69,735	$ -
2029	415,408	8,565	406,843	68,474	68,474	$ -
2030	406,843	8,565	398,278	67,213	67,213	$ -
2031	398,278	8,565	389,712	65,952	65,952	$ -
2032	389,712	8,565	381,147	64,690	64,690	$ -
2033	381,147	8,565	372,582	63,429	63,429	$ -
2034	372,582	8,565	364,017	62,168	62,168	$ -
2035	364,017	8,565	355,452	60,907	60,907	$ -
2036	355,452	8,565	346,887	59,645	59,645	$ -
2037	346,887	8,565	338,322	58,384	58,384	$ -
2038	338,322	8,565	329,757	57,123	57,123	$ -
2039	329,757	8,565	321,192	55,862	55,862	$ -
2040	321,192	8,565	312,626	54,600	54,600	$ -
2041	312,626	8,565	304,061	53,339	53,339	$ -
2042	304,061	8,565	295,496	52,078	52,078	$ -
2043	295,496	8,565	286,931	50,817	50,817	$ -
2044	286,931	8,565	278,366	49,556	49,556	$ -
2045	278,366	8,565	269,801	48,294	48,294	$ -
2046	269,801	8,565	261,236	47,033	47,033	$ -
2047	261,236	8,565	252,671	45,772	45,772	$ -
2048	252,671	8,565	244,106	44,511	44,511	$ -
2049	244,106	8,565	235,541	43,249	43,249	$ -
2050	235,541	8,565	226,975	41,988	41,988	$ -
2051	226,975	8,565	218,410	40,727	40,727	$ -
2052	218,410	8,565	209,845	39,466	39,466	$ -
2053	209,845	8,565	201,280	38,204	38,204	$ -
2054	201,280	8,565	192,715	36,943	36,943	$ -
2055	192,715	8,565	184,150	35,682	35,682	$ -
2056	184,150	8,565	175,585	34,421	34,421	$ -
2057	175,585	8,565	167,020	33,159	33,159	$ -
2058	167,020	8,565	158,455	31,898	31,898	$ -
2059	158,455	8,565	149,889	30,637	30,637	$ -
2060	149,889	8,565	141,324	29,376	29,376	$ -
2061	141,324	8,565	132,759	28,114	28,114	$ -
2062	132,759	8,565	124,194	26,853	26,853	$ -
2063	124,194	8,565	115,629	25,592	25,592	$ -
2064	115,629	8,565	107,064	24,331	24,331	$ -
2065	107,064	8,565	98,499	23,069	23,069	$ -
2066	98,499	8,565	89,934	21,808	21,808	$ -
2067	89,934	8,565	81,369	20,547	20,547	$ -
2068	81,369	8,565	72,803	19,286	19,286	$ -
2069	72,803	8,565	64,238	18,024	18,024	$ -
2070	64,238	8,565	55,673	16,763	16,763	$ -
2071	55,673	8,565	47,108	15,502	15,502	$ -
2072	47,108	8,565	38,543	14,241	14,241	$ -
Project Totals		509,624		3,082,560	3,082,560	-

CUMULATIVE HISTORY OF PROJECTED ANNUAL REVENUE REQUIREMENTS:

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

RTEP Projected Rev. Req't.From Prior Year Template w/o Incentives		RTEP Projected Rev. Req't.From Prior Year Template with Incentives **		
$ 92,625		$ 92,625		

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

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

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

I & 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	**3,243,481**
Current Projected Year ARR w/ Incentive	**3,243,481**
Current Projected Year Incentive ARR	**-**

Details			
Investment	20,393,626	Current Year	2014
Service Year (yyyy)	2013	ROE increase accepted by FERC (Basis Points)	-
Service Month (1-12)	4	FCR w/o incentives, less depreciation	14.73%
Useful life	64	FCR w/incentives approved for these facilities, less dep.	14.73%
CIAC (Yes or No)	No	Annual Depreciation Expense	318,650

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	20,393,626	212,434	20,181,192	3,184,187	3,184,187	$ -
2014	20,181,192	318,650	19,862,542	3,243,481	3,243,481	$ -
2015	19,862,542	318,650	19,543,892	3,196,559	3,196,559	$ -
2016	19,543,892	318,650	19,225,241	3,149,636	3,149,636	$ -
2017	19,225,241	318,650	18,906,591	3,102,714	3,102,714	$ -
2018	18,906,591	318,650	18,587,940	3,055,792	3,055,792	$ -
2019	18,587,940	318,650	18,269,290	3,008,869	3,008,869	$ -
2020	18,269,290	318,650	17,950,640	2,961,947	2,961,947	$ -
2021	17,950,640	318,650	17,631,989	2,915,024	2,915,024	$ -
2022	17,631,989	318,650	17,313,339	2,868,102	2,868,102	$ -
2023	17,313,339	318,650	16,994,688	2,821,179	2,821,179	$ -
2024	16,994,688	318,650	16,676,038	2,774,257	2,774,257	$ -
2025	16,676,038	318,650	16,357,388	2,727,335	2,727,335	$ -
2026	16,357,388	318,650	16,038,737	2,680,412	2,680,412	$ -
2027	16,038,737	318,650	15,720,087	2,633,490	2,633,490	$ -
2028	15,720,087	318,650	15,401,436	2,586,567	2,586,567	$ -
2029	15,401,436	318,650	15,082,786	2,539,645	2,539,645	$ -
2030	15,082,786	318,650	14,764,135	2,492,722	2,492,722	$ -
2031	14,764,135	318,650	14,445,485	2,445,800	2,445,800	$ -
2032	14,445,485	318,650	14,126,835	2,398,878	2,398,878	$ -
2033	14,126,835	318,650	13,808,184	2,351,955	2,351,955	$ -
2034	13,808,184	318,650	13,489,534	2,305,033	2,305,033	$ -
2035	13,489,534	318,650	13,170,883	2,258,110	2,258,110	$ -
2036	13,170,883	318,650	12,852,233	2,211,188	2,211,188	$ -
2037	12,852,233	318,650	12,533,583	2,164,266	2,164,266	$ -
2038	12,533,583	318,650	12,214,932	2,117,343	2,117,343	$ -
2039	12,214,932	318,650	11,896,282	2,070,421	2,070,421	$ -
2040	11,896,282	318,650	11,577,631	2,023,498	2,023,498	$ -
2041	11,577,631	318,650	11,258,981	1,976,576	1,976,576	$ -
2042	11,258,981	318,650	10,940,331	1,929,653	1,929,653	$ -
2043	10,940,331	318,650	10,621,680	1,882,731	1,882,731	$ -
2044	10,621,680	318,650	10,303,030	1,835,809	1,835,809	$ -
2045	10,303,030	318,650	9,984,379	1,788,886	1,788,886	$ -
2046	9,984,379	318,650	9,665,729	1,741,964	1,741,964	$ -
2047	9,665,729	318,650	9,347,079	1,695,041	1,695,041	$ -
2048	9,347,079	318,650	9,028,428	1,648,119	1,648,119	$ -
2049	9,028,428	318,650	8,709,778	1,601,197	1,601,197	$ -
2050	8,709,778	318,650	8,391,127	1,554,274	1,554,274	$ -
2051	8,391,127	318,650	8,072,477	1,507,352	1,507,352	$ -
2052	8,072,477	318,650	7,753,827	1,460,429	1,460,429	$ -
2053	7,753,827	318,650	7,435,176	1,413,507	1,413,507	$ -
2054	7,435,176	318,650	7,116,526	1,366,584	1,366,584	$ -
2055	7,116,526	318,650	6,797,875	1,319,662	1,319,662	$ -
2056	6,797,875	318,650	6,479,225	1,272,740	1,272,740	$ -
2057	6,479,225	318,650	6,160,575	1,225,817	1,225,817	$ -
2058	6,160,575	318,650	5,841,924	1,178,895	1,178,895	$ -
2059	5,841,924	318,650	5,523,274	1,131,972	1,131,972	$ -
2060	5,523,274	318,650	5,204,623	1,085,050	1,085,050	$ -
2061	5,204,623	318,650	4,885,973	1,038,127	1,038,127	$ -
2062	4,885,973	318,650	4,567,322	991,205	991,205	$ -
2063	4,567,322	318,650	4,248,672	944,283	944,283	$ -
2064	4,248,672	318,650	3,930,022	897,360	897,360	$ -
2065	3,930,022	318,650	3,611,371	850,438	850,438	$ -
2066	3,611,371	318,650	3,292,721	803,515	803,515	$ -
2067	3,292,721	318,650	2,974,070	756,593	756,593	$ -
2068	2,974,070	318,650	2,655,420	709,671	709,671	$ -
2069	2,655,420	318,650	2,336,770	662,748	662,748	$ -
2070	2,336,770	318,650	2,018,119	615,826	615,826	$ -
2071	2,018,119	318,650	1,699,469	568,903	568,903	$ -
2072	1,699,469	318,650	1,380,818	521,981	521,981	$ -
Project Totals		19,012,808		114,265,318	114,265,318	-

CUMULATIVE HISTORY OF PROJECTED ANNUAL REVENUE REQUIREMENTS:

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

RTEP Projected Rev. Req't.From Prior Year Template w/o Incentives		RTEP Projected Rev. Req't.From Prior Year Template with Incentives **		
$ 1,301,059		$ 1,301,059		

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

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

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

I & 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: b1659.14 (Fort Wayne - Marion: Relocate 138 kV line due to new 765 kV build into Sorenson)

Current Projected Year ARR	**239,172**
Current Projected Year ARR w/ Incentive	**239,172**
Current Projected Year Incentive ARR	**-**

Details			
Investment	1,624,220	Current Year	**2014**
Service Year (yyyy)	2014	ROE increase accepted by FERC (Basis Points)	-
Service Month (1-12)	12	FCR w/o incentives, less depreciation	14.73%
Useful life	64	FCR w/incentives approved for these facilities, less dep.	14.73%
CIAC (Yes or No)	No	Annual Depreciation Expense	25,378

Investment Year	Beginning Balance	Depreciation Expense	Ending Balance	RTEP Rev. Req't. w/o Incentives	RTEP Rev. Req't. with Incentives **	Incentive Rev. Requirement ##
2014	1,624,220	-	1,624,220	239,172	239,172	$ -
2015	1,624,220	25,378	1,598,842	260,814	260,814	$ -
2016	1,598,842	25,378	1,573,463	257,077	257,077	$ -
2017	1,573,463	25,378	1,548,085	253,339	253,339	$ -
2018	1,548,085	25,378	1,522,706	249,602	249,602	$ -
2019	1,522,706	25,378	1,497,328	245,865	245,865	$ -
2020	1,497,328	25,378	1,471,949	242,128	242,128	$ -
2021	1,471,949	25,378	1,446,571	238,391	238,391	$ -
2022	1,446,571	25,378	1,421,193	234,654	234,654	$ -
2023	1,421,193	25,378	1,395,814	230,917	230,917	$ -
2024	1,395,814	25,378	1,370,436	227,180	227,180	$ -
2025	1,370,436	25,378	1,345,057	223,443	223,443	$ -
2026	1,345,057	25,378	1,319,679	219,706	219,706	$ -
2027	1,319,679	25,378	1,294,300	215,969	215,969	$ -
2028	1,294,300	25,378	1,268,922	212,232	212,232	$ -
2029	1,268,922	25,378	1,243,543	208,495	208,495	$ -
2030	1,243,543	25,378	1,218,165	204,758	204,758	$ -
2031	1,218,165	25,378	1,192,787	201,021	201,021	$ -
2032	1,192,787	25,378	1,167,408	197,283	197,283	$ -
2033	1,167,408	25,378	1,142,030	193,546	193,546	$ -
2034	1,142,030	25,378	1,116,651	189,809	189,809	$ -
2035	1,116,651	25,378	1,091,273	186,072	186,072	$ -
2036	1,091,273	25,378	1,065,894	182,335	182,335	$ -
2037	1,065,894	25,378	1,040,516	178,598	178,598	$ -
2038	1,040,516	25,378	1,015,138	174,861	174,861	$ -
2039	1,015,138	25,378	989,759	171,124	171,124	$ -
2040	989,759	25,378	964,381	167,387	167,387	$ -
2041	964,381	25,378	939,002	163,650	163,650	$ -
2042	939,002	25,378	913,624	159,913	159,913	$ -
2043	913,624	25,378	888,245	156,176	156,176	$ -
2044	888,245	25,378	862,867	152,439	152,439	$ -
2045	862,867	25,378	837,488	148,702	148,702	$ -
2046	837,488	25,378	812,110	144,965	144,965	$ -
2047	812,110	25,378	786,732	141,227	141,227	$ -
2048	786,732	25,378	761,353	137,490	137,490	$ -
2049	761,353	25,378	735,975	133,753	133,753	$ -
2050	735,975	25,378	710,596	130,016	130,016	$ -
2051	710,596	25,378	685,218	126,279	126,279	$ -
2052	685,218	25,378	659,839	122,542	122,542	$ -
2053	659,839	25,378	634,461	118,805	118,805	$ -
2054	634,461	25,378	609,083	115,068	115,068	$ -
2055	609,083	25,378	583,704	111,331	111,331	$ -
2056	583,704	25,378	558,326	107,594	107,594	$ -
2057	558,326	25,378	532,947	103,857	103,857	$ -
2058	532,947	25,378	507,569	100,120	100,120	$ -
2059	507,569	25,378	482,190	96,383	96,383	$ -
2060	482,190	25,378	456,812	92,646	92,646	$ -
2061	456,812	25,378	431,433	88,909	88,909	$ -
2062	431,433	25,378	406,055	85,171	85,171	$ -
2063	406,055	25,378	380,677	81,434	81,434	$ -
2064	380,677	25,378	355,298	77,697	77,697	$ -
2065	355,298	25,378	329,920	73,960	73,960	$ -
2066	329,920	25,378	304,541	70,223	70,223	$ -
2067	304,541	25,378	279,163	66,486	66,486	$ -
2068	279,163	25,378	253,784	62,749	62,749	$ -
2069	253,784	25,378	228,406	59,012	59,012	$ -
2070	228,406	25,378	203,028	55,275	55,275	$ -
2071	203,028	25,378	177,649	51,538	51,538	$ -
2072	177,649	25,378	152,271	47,801	47,801	$ -
2073	152,271	25,378	126,892	44,064	44,064	$ -
Project Totals		1,497,328		9,233,055	9,233,055	-

CUMULATIVE HISTORY OF PROJECTED ANNUAL REVENUE REQUIREMENTS:

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

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

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

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

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

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: b2048 (Tanners Creek - Support for Transformer A/B Replacement)**

Current Projected Year ARR	**139,756**
Current Projected Year ARR w/ Incentive	**139,756**
Current Projected Year Incentive ARR	**-**

Details			
Investment	870,334	Current Year	**2014**
Service Year (yyyy)	2013	ROE increase accepted by FERC (Basis Points)	-
Service Month (1-12)	12	FCR w/o incentives, less depreciation	14.73%
Useful life	64	FCR w/incentives approved for these facilities, less dep.	14.73%
CIAC (Yes or No)	No	Annual Depreciation Expense	13,599

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.

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	870,334	-	870,334	128,160	128,160	$ -	$ -		$ -		
2014	870,334	13,599	856,735	139,756	139,756	$ -					
2015	856,735	13,599	843,136	137,754	137,754	$ -					
2016	843,136	13,599	829,537	135,751	135,751	$ -					
2017	829,537	13,599	815,938	133,749	133,749	$ -					
2018	815,938	13,599	802,339	131,746	131,746	$ -					
2019	802,339	13,599	788,740	129,744	129,744	$ -					
2020	788,740	13,599	775,141	127,741	127,741	$ -					
2021	775,141	13,599	761,542	125,739	125,739	$ -					
2022	761,542	13,599	747,943	123,736	123,736	$ -					
2023	747,943	13,599	734,344	121,734	121,734	$ -					
2024	734,344	13,599	720,745	119,731	119,731	$ -					
2025	720,745	13,599	707,146	117,729	117,729	$ -					
2026	707,146	13,599	693,547	115,726	115,726	$ -					
2027	693,547	13,599	679,948	113,724	113,724	$ -					
2028	679,948	13,599	666,349	111,721	111,721	$ -					
2029	666,349	13,599	652,751	109,719	109,719	$ -					
2030	652,751	13,599	639,152	107,716	107,716	$ -					
2031	639,152	13,599	625,553	105,714	105,714	$ -					
2032	625,553	13,599	611,954	103,711	103,711	$ -					
2033	611,954	13,599	598,355	101,709	101,709	$ -					
2034	598,355	13,599	584,756	99,706	99,706	$ -					
2035	584,756	13,599	571,157	97,704	97,704	$ -					
2036	571,157	13,599	557,558	95,701	95,701	$ -					
2037	557,558	13,599	543,959	93,699	93,699	$ -					
2038	543,959	13,599	530,360	91,696	91,696	$ -					
2039	530,360	13,599	516,761	89,694	89,694	$ -					
2040	516,761	13,599	503,162	87,691	87,691	$ -					
2041	503,162	13,599	489,563	85,689	85,689	$ -					
2042	489,563	13,599	475,964	83,686	83,686	$ -					
2043	475,964	13,599	462,365	81,684	81,684	$ -					
2044	462,365	13,599	448,766	79,681	79,681	$ -					
2045	448,766	13,599	435,167	77,679	77,679	$ -					
2046	435,167	13,599	421,568	75,676	75,676	$ -					
2047	421,568	13,599	407,969	73,674	73,674	$ -					
2048	407,969	13,599	394,370	71,671	71,671	$ -					
2049	394,370	13,599	380,771	69,669	69,669	$ -					
2050	380,771	13,599	367,172	67,666	67,666	$ -					
2051	367,172	13,599	353,573	65,664	65,664	$ -					
2052	353,573	13,599	339,974	63,661	63,661	$ -					
2053	339,974	13,599	326,375	61,659	61,659	$ -					
2054	326,375	13,599	312,776	59,656	59,656	$ -					
2055	312,776	13,599	299,177	57,654	57,654	$ -					
2056	299,177	13,599	285,578	55,651	55,651	$ -					
2057	285,578	13,599	271,979	53,649	53,649	$ -					
2058	271,979	13,599	258,380	51,646	51,646	$ -					
2059	258,380	13,599	244,781	49,644	49,644	$ -					
2060	244,781	13,599	231,182	47,641	47,641	$ -					
2061	231,182	13,599	217,584	45,639	45,639	$ -					
2062	217,584	13,599	203,985	43,636	43,636	$ -					
2063	203,985	13,599	190,386	41,634	41,634	$ -					
2064	190,386	13,599	176,787	39,631	39,631	$ -					
2065	176,787	13,599	163,188	37,629	37,629	$ -					
2066	163,188	13,599	149,589	35,626	35,626	$ -					
2067	149,589	13,599	135,990	33,624	33,624	$ -					
2068	135,990	13,599	122,391	31,621	31,621	$ -					
2069	122,391	13,599	108,792	29,619	29,619	$ -					
2070	108,792	13,599	95,193	27,616	27,616	$ -					
2071	95,193	13,599	81,594	25,614	25,614	$ -					
2072	81,594	13,599	67,995	23,611	23,611	$ -					
Project Totals		802,339		4,947,508	4,947,508	-					

** 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 2013 FF1 Balances
Worksheet K Supporting Calculation of TRUE-UP PJM RTEP Project Revenue Requirement Billed to Benefiting Zones
INDIANA MICHIGAN POWER COMPANY

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-Up TCOS, ln 164) 11.49%
Project ROE Incentive Adder 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 term debt, cost of preferred stock and equity percentage is from the True-Up TCOS, lns 162 through164)

	%	Cost		Weighted cost
Long Term Debt	45.70%	6.14%		2.804%
Preferred Stock	0.00%	0.00%		0.000%
Common Stock	54.30%	11.49%		6.240%
			R =	9.044%

SUMMARY OF TRUED-UP ANNUAL REVENUE REQUIREMENTS FOR RTEPPROJECTS			
	Rev Require	W Incentives	Incentive Amounts
TRUE-UP YEAR 2013			
As Projected in Prior Year WS J	$ 2,666,168	$ 2,666,168	$ -
Actual after True-up	$ 2,973,246	$ 2,973,246	$ -
True-up of ARR For 2013	307,078	307,078	-

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

Rate Base (True-Up TCOS, ln 78)	556,673,150
R (from A. above)	9.044%
Return (Rate Base x R)	50,344,245

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

Return (from B. above)	50,344,245
Effective Tax Rate (True-Up TCOS, ln 126)	44.11%
Income Tax Calculation (Return x CIT)	22,204,920
ITC Adjustment	(1,611,277)
Income Taxes	20,593,644

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, ln 1)	125,502,776
T.E.A. & Lease Payments (True-Up TCOS, Lns 105 & 106)	-
Return (True-Up TCOS, ln 134)	50,344,245
Income Taxes (True-Up TCOS, ln 133)	20,593,644
Annual Revenue Requirement, Less TEA Charges, Return and Taxes	54,564,887

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

Annual Revenue Requirement, Less TEA Charges, Return and Taxes	54,564,887
Return (from I.B. above)	50,344,245
Income Taxes (from I.C. above)	20,593,644
Annual Revenue Requirement, with 0 Basis Point ROE increase	125,502,776
Depreciation (True-Up TCOS, ln 111)	19,540,798
Annual Rev. Req, w/ 0 Basis Point ROE increase, less Depreciation	105,961,978

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

Net Transmission Plant (True-Up TCOS, ln 48)	699,456,649
Annual Revenue Requirement, with 0 Basis Point ROE increase	125,502,776
FCR with 0 Basis Point increase in ROE	17.94%
Annual Rev. Req, w / 0 Basis Point ROE increase, less Dep.	105,961,978
FCR with 0 Basis Point ROE increase, less Depreciation	15.15%
FCR less Depreciation (True-Up TCOS, ln 9)	15.15%
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, ln 58,(b)):	1,278,027,455
Transmission Plant @ End of Historic Period () (P.207, ln 58,(g)):	1,320,667,751
Subtotal	2,598,695,206
Average Transmission Plant Balance for	1,299,347,603
Annual Depreciation Rate (True-Up TCOS, ln 111)	20,181,719
Composite Depreciation Rate	1.55%
Depreciable Life for Composite Depreciation Rate	64.38
Round to nearest whole year	64

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

2013	Rev Require	W Incentives	Incentive Amounts
Prior Yr Projected	1,272,484	1,272,484	-
Prior Yr True-Up	1,311,134	1,311,134	-
True-Up Adjustment	38,650	38,650	-

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	15.15%
Useful life	64	FCR w/incentives approved for these facilities, less dep.	15.15%
CIAC (Yes or No)	No	Annual Depreciation Expense	129,950

TRUE UP OF PROJECT REVENUE REQUIREMENT FOR PRIOR YEAR:

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

Investment Year	Beginning Balance	Depreciation Expense	Ending Balance	Average Balance	RTEP Rev. Req't. w/o Incentives	RTEP Rev. Req't. with Incentives **	Incentive Rev. Requirement ##	RTEP Projected Rev. Req't.From Prior Year WS J w/o Incentives	RTEP Rev Req't True-up w/o Incentives	RTEP Projected Rev. Req't.From Prior Year WS J with Incentives **	RTEP Rev Req't True-up with Incentives **	True-up of Incentive with Incentives **
2009	8,316,811	64,975	8,251,836	8,284,323	1,319,983	1,319,983	$ -	$ -	$ -	$ -	$ -	$ -
2010	8,251,836	129,950	8,121,886	8,186,861	1,370,193	1,370,193	$ -	$ 1,408,114	$ (37,922)	$ 1,408,114	$ (37,922)	$ -
2011	8,121,886	129,950	7,991,936	8,056,911	1,350,506	1,350,506	$ -	$ 1,487,355	$ (136,849)	$ 1,487,355	$ (136,849)	$ -
2012	7,991,936	129,950	7,861,985	7,926,960	1,330,820	1,330,820	$ -	$ 1,319,695	$ 11,125	$ 1,319,695	$ 11,125	$ -
2013	7,861,985	129,950	7,732,035	7,797,010	1,311,134	1,311,134	$ -	$ 1,272,484	$ 38,650	$ 1,272,484	$ 38,650	$ -
2014	7,732,035	129,950	7,602,085	7,667,060	1,291,447	1,291,447	$ -		$ -		$ -	$ -
2015	7,602,085	129,950	7,472,135	7,537,110	1,271,761	1,271,761	$ -		$ -		$ -	$ -
2016	7,472,135	129,950	7,342,185	7,407,160	1,252,074	1,252,074	$ -		$ -		$ -	$ -
2017	7,342,185	129,950	7,212,235	7,277,210	1,232,388	1,232,388	$ -		$ -		$ -	$ -
2018	7,212,235	129,950	7,082,284	7,147,259	1,212,702	1,212,702	$ -		$ -		$ -	$ -
2019	7,082,284	129,950	6,952,334	7,017,309	1,193,015	1,193,015	$ -		$ -		$ -	$ -
2020	6,952,334	129,950	6,822,384	6,887,359	1,173,329	1,173,329	$ -		$ -		$ -	$ -
2021	6,822,384	129,950	6,692,434	6,757,409	1,153,643	1,153,643	$ -		$ -		$ -	$ -
2022	6,692,434	129,950	6,562,484	6,627,459	1,133,956	1,133,956	$ -		$ -		$ -	$ -
2023	6,562,484	129,950	6,432,534	6,497,509	1,114,270	1,114,270	$ -		$ -		$ -	$ -
2024	6,432,534	129,950	6,302,583	6,367,558	1,094,583	1,094,583	$ -		$ -		$ -	$ -
2025	6,302,583	129,950	6,172,633	6,237,608	1,074,897	1,074,897	$ -		$ -		$ -	$ -
2026	6,172,633	129,950	6,042,683	6,107,658	1,055,211	1,055,211	$ -		$ -		$ -	$ -
2027	6,042,683	129,950	5,912,733	5,977,708	1,035,524	1,035,524	$ -		$ -		$ -	$ -
2028	5,912,733	129,950	5,782,783	5,847,758	1,015,838	1,015,838	$ -		$ -		$ -	$ -
2029	5,782,783	129,950	5,652,832	5,717,808	996,151	996,151	$ -		$ -		$ -	$ -
2030	5,652,832	129,950	5,522,882	5,587,857	976,465	976,465	$ -		$ -		$ -	$ -
2031	5,522,882	129,950	5,392,932	5,457,907	956,779	956,779	$ -		$ -		$ -	$ -
2032	5,392,932	129,950	5,262,982	5,327,957	937,092	937,092	$ -		$ -		$ -	$ -
2033	5,262,982	129,950	5,133,032	5,198,007	917,406	917,406	$ -		$ -		$ -	$ -
2034	5,133,032	129,950	5,003,082	5,068,057	897,719	897,719	$ -		$ -		$ -	$ -
2035	5,003,082	129,950	4,873,131	4,938,107	878,033	878,033	$ -		$ -		$ -	$ -
2036	4,873,131	129,950	4,743,181	4,808,156	858,347	858,347	$ -		$ -		$ -	$ -
2037	4,743,181	129,950	4,613,231	4,678,206	838,660	838,660	$ -		$ -		$ -	$ -
2038	4,613,231	129,950	4,483,281	4,548,256	818,974	818,974	$ -		$ -		$ -	$ -
2039	4,483,281	129,950	4,353,331	4,418,306	799,287	799,287	$ -		$ -		$ -	$ -
2040	4,353,331	129,950	4,223,381	4,288,356	779,601	779,601	$ -		$ -		$ -	$ -
2041	4,223,381	129,950	4,093,430	4,158,406	759,915	759,915	$ -		$ -		$ -	$ -
2042	4,093,430	129,950	3,963,480	4,028,455	740,228	740,228	$ -		$ -		$ -	$ -
2043	3,963,480	129,950	3,833,530	3,898,505	720,542	720,542	$ -		$ -		$ -	$ -
2044	3,833,530	129,950	3,703,580	3,768,555	700,856	700,856	$ -		$ -		$ -	$ -
2045	3,703,580	129,950	3,573,630	3,638,605	681,169	681,169	$ -		$ -		$ -	$ -
2046	3,573,630	129,950	3,443,680	3,508,655	661,483	661,483	$ -		$ -		$ -	$ -
2047	3,443,680	129,950	3,313,729	3,378,704	641,796	641,796	$ -		$ -		$ -	$ -
2048	3,313,729	129,950	3,183,779	3,248,754	622,110	622,110	$ -		$ -		$ -	$ -
2049	3,183,779	129,950	3,053,829	3,118,804	602,424	602,424	$ -		$ -		$ -	$ -
2050	3,053,829	129,950	2,923,879	2,988,854	582,737	582,737	$ -		$ -		$ -	$ -
2051	2,923,879	129,950	2,793,929	2,858,904	563,051	563,051	$ -		$ -		$ -	$ -
2052	2,793,929	129,950	2,663,979	2,728,954	543,364	543,364	$ -		$ -		$ -	$ -
2053	2,663,979	129,950	2,534,028	2,599,003	523,678	523,678	$ -		$ -		$ -	$ -
2054	2,534,028	129,950	2,404,078	2,469,053	503,992	503,992	$ -		$ -		$ -	$ -
2055	2,404,078	129,950	2,274,128	2,339,103	484,305	484,305	$ -		$ -		$ -	$ -
2056	2,274,128	129,950	2,144,178	2,209,153	464,619	464,619	$ -		$ -		$ -	$ -
2057	2,144,178	129,950	2,014,228	2,079,203	444,932	444,932	$ -		$ -		$ -	$ -
2058	2,014,228	129,950	1,884,277	1,949,253	425,246	425,246	$ -		$ -		$ -	$ -
2059	1,884,277	129,950	1,754,327	1,819,302	405,560	405,560	$ -		$ -		$ -	$ -
2060	1,754,327	129,950	1,624,377	1,689,352	385,873	385,873	$ -		$ -		$ -	$ -
2061	1,624,377	129,950	1,494,427	1,559,402	366,187	366,187	$ -		$ -		$ -	$ -
2062	1,494,427	129,950	1,364,477	1,429,452	346,500	346,500	$ -		$ -		$ -	$ -
2063	1,364,477	129,950	1,234,527	1,299,502	326,814	326,814	$ -		$ -		$ -	$ -
2064	1,234,527	129,950	1,104,576	1,169,552	307,128	307,128	$ -		$ -		$ -	$ -
2065	1,104,576	129,950	974,626	1,039,601	287,441	287,441	$ -		$ -		$ -	$ -
2066	974,626	129,950	844,676	909,651	267,755	267,755	$ -		$ -		$ -	$ -
2067	844,676	129,950	714,726	779,701	248,069	248,069	$ -		$ -		$ -	$ -
2068	714,726	129,950	584,776	649,751	228,382	228,382	$ -		$ -		$ -	$ -
Project Totals		7,732,035			48,477,944	48,477,944	-					

** 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

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 bank at Rockport Station)**

2013	Rev Require	W Incentives	Incentive Amounts
Prior Yr Projected	92,625	92,625	-
Prior Yr True-Up	87,001	87,001	-
True-Up Adjustment	(5,624)	(5,624)	-

Details			
Investment	548,167	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	15.15%
Useful life	64	FCR w/incentives approved for these facilities, less dep.	15.15%
CIAC (Yes or No)	No	Annual Depreciation Expense	8,565

TRUE UP OF PROJECT REVENUE REQUIREMENT FOR PRIOR YEAR:

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

Investment Year	Beginning Balance	Depreciation Expense	Ending Balance	Average Balance	RTEP Rev. Req't. w/o Incentives	RTEP Rev. Req't. with Incentives **	Incentive Rev. Requirement ##	RTEP Projected Rev. Req't.From Prior Year WS J w/o Incentives	RTEP Rev Req't True-up w/o Incentives	RTEP Projected Rev. Req't.From Prior Year WS J with Incentives **	RTEP Rev Req't True-up with Incentives **	True-up of Incentive with Incentives **
2013	548,167	4,283	543,884	546,026	87,001	87,001	$ -	$ 92,625	$ (5,624)	$ 92,625	$ (5,624)	$ -
2014	543,884	8,565	535,319	539,602	90,310	90,310	$ -		$ -		$ -	$ -
2015	535,319	8,565	526,754	531,037	89,013	89,013	$ -		$ -		$ -	$ -
2016	526,754	8,565	518,189	522,472	87,715	87,715	$ -		$ -		$ -	$ -
2017	518,189	8,565	509,624	513,907	86,418	86,418	$ -		$ -		$ -	$ -
2018	509,624	8,565	501,059	505,341	85,120	85,120	$ -		$ -		$ -	$ -
2019	501,059	8,565	492,494	496,776	83,823	83,823	$ -		$ -		$ -	$ -
2020	492,494	8,565	483,929	488,211	82,525	82,525	$ -		$ -		$ -	$ -
2021	483,929	8,565	475,364	479,646	81,228	81,228	$ -		$ -		$ -	$ -
2022	475,364	8,565	466,798	471,081	79,930	79,930	$ -		$ -		$ -	$ -
2023	466,798	8,565	458,233	462,516	78,632	78,632	$ -		$ -		$ -	$ -
2024	458,233	8,565	449,668	453,951	77,335	77,335	$ -		$ -		$ -	$ -
2025	449,668	8,565	441,103	445,386	76,037	76,037	$ -		$ -		$ -	$ -
2026	441,103	8,565	432,538	436,821	74,740	74,740	$ -		$ -		$ -	$ -
2027	432,538	8,565	423,973	428,255	73,442	73,442	$ -		$ -		$ -	$ -
2028	423,973	8,565	415,408	419,690	72,145	72,145	$ -		$ -		$ -	$ -
2029	415,408	8,565	406,843	411,125	70,847	70,847	$ -		$ -		$ -	$ -
2030	406,843	8,565	398,278	402,560	69,550	69,550	$ -		$ -		$ -	$ -
2031	398,278	8,565	389,712	393,995	68,252	68,252	$ -		$ -		$ -	$ -
2032	389,712	8,565	381,147	385,430	66,955	66,955	$ -		$ -		$ -	$ -
2033	381,147	8,565	372,582	376,865	65,657	65,657	$ -		$ -		$ -	$ -
2034	372,582	8,565	364,017	368,300	64,360	64,360	$ -		$ -		$ -	$ -
2035	364,017	8,565	355,452	359,735	63,062	63,062	$ -		$ -		$ -	$ -
2036	355,452	8,565	346,887	351,169	61,764	61,764	$ -		$ -		$ -	$ -
2037	346,887	8,565	338,322	342,604	60,467	60,467	$ -		$ -		$ -	$ -
2038	338,322	8,565	329,757	334,039	59,169	59,169	$ -		$ -		$ -	$ -
2039	329,757	8,565	321,192	325,474	57,872	57,872	$ -		$ -		$ -	$ -
2040	321,192	8,565	312,626	316,909	56,574	56,574	$ -		$ -		$ -	$ -
2041	312,626	8,565	304,061	308,344	55,277	55,277	$ -		$ -		$ -	$ -
2042	304,061	8,565	295,496	299,779	53,979	53,979	$ -		$ -		$ -	$ -
2043	295,496	8,565	286,931	291,214	52,682	52,682	$ -		$ -		$ -	$ -
2044	286,931	8,565	278,366	282,649	51,384	51,384	$ -		$ -		$ -	$ -
2045	278,366	8,565	269,801	274,084	50,087	50,087	$ -		$ -		$ -	$ -
2046	269,801	8,565	261,236	265,518	48,789	48,789	$ -		$ -		$ -	$ -
2047	261,236	8,565	252,671	256,953	47,491	47,491	$ -		$ -		$ -	$ -
2048	252,671	8,565	244,106	248,388	46,194	46,194	$ -		$ -		$ -	$ -
2049	244,106	8,565	235,541	239,823	44,896	44,896	$ -		$ -		$ -	$ -
2050	235,541	8,565	226,975	231,258	43,599	43,599	$ -		$ -		$ -	$ -
2051	226,975	8,565	218,410	222,693	42,301	42,301	$ -		$ -		$ -	$ -
2052	218,410	8,565	209,845	214,128	41,004	41,004	$ -		$ -		$ -	$ -
2053	209,845	8,565	201,280	205,563	39,706	39,706	$ -		$ -		$ -	$ -
2054	201,280	8,565	192,715	196,998	38,409	38,409	$ -		$ -		$ -	$ -
2055	192,715	8,565	184,150	188,432	37,111	37,111	$ -		$ -		$ -	$ -
2056	184,150	8,565	175,585	179,867	35,814	35,814	$ -		$ -		$ -	$ -
2057	175,585	8,565	167,020	171,302	34,516	34,516	$ -		$ -		$ -	$ -
2058	167,020	8,565	158,455	162,737	33,218	33,218	$ -		$ -		$ -	$ -
2059	158,455	8,565	149,889	154,172	31,921	31,921	$ -		$ -		$ -	$ -
2060	149,889	8,565	141,324	145,607	30,623	30,623	$ -		$ -		$ -	$ -
2061	141,324	8,565	132,759	137,042	29,326	29,326	$ -		$ -		$ -	$ -
2062	132,759	8,565	124,194	128,477	28,028	28,028	$ -		$ -		$ -	$ -
2063	124,194	8,565	115,629	119,912	26,731	26,731	$ -		$ -		$ -	$ -
2064	115,629	8,565	107,064	111,346	25,433	25,433	$ -		$ -		$ -	$ -
2065	107,064	8,565	98,499	102,781	24,136	24,136	$ -		$ -		$ -	$ -
2066	98,499	8,565	89,934	94,216	22,838	22,838	$ -		$ -		$ -	$ -
2067	89,934	8,565	81,369	85,651	21,541	21,541	$ -		$ -		$ -	$ -
2068	81,369	8,565	72,803	77,086	20,243	20,243	$ -		$ -		$ -	$ -
2069	72,803	8,565	64,238	68,521	18,945	18,945	$ -		$ -		$ -	$ -
2070	64,238	8,565	55,673	59,956	17,648	17,648	$ -		$ -		$ -	$ -
2071	55,673	8,565	47,108	51,391	16,350	16,350	$ -		$ -		$ -	$ -
2072	47,108	8,565	38,543	42,826	15,053	15,053	$ -		$ -		$ -	$ -
Project Totals		509,624			3,195,216	3,195,216	-					

** 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

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 Amounts
Prior Yr Projected	1,301,059	1,301,059	-
Prior Yr True-Up	1,455,631	1,455,631	-
True-Up Adjustment	154,572	154,572	-

Details			
Investment	9,034,478	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	15.15%
Useful life	64	FCR w/incentives approved for these facilities, less dep.	15.15%
CIAC (Yes or No)	No	Annual Depreciation Expense	141,164

TRUE UP OF PROJECT REVENUE REQUIREMENT FOR PRIOR YEAR:

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

Investment Year	Beginning Balance	Depreciation Expense	Ending Balance	Average Balance	RTEP Rev. Req't. w/o Incentives	RTEP Rev. Req't. with Incentives **	Incentive Rev. Requirement ##	RTEP Projected Rev. Req't.From Prior Year WS J w/o Incentives	RTEP Rev Req't True-up w/o Incentives	RTEP Projected Rev. Req't.From Prior Year WS J with Incentives **	RTEP Rev Req't True-up with Incentives **	True-up of Incentive with Incentives **
2013	9,034,478	94,109	8,940,369	8,987,423	1,455,631	1,455,631	$ -	$ 1,301,059	$ 154,572	$ 1,301,059	$ 154,572	$ -
2014	8,940,369	141,164	8,799,205	8,869,787	1,484,864	1,484,864	$ -		$ -		$ -	$ -
2015	8,799,205	141,164	8,658,041	8,728,623	1,463,479	1,463,479	$ -		$ -		$ -	$ -
2016	8,658,041	141,164	8,516,878	8,587,460	1,442,094	1,442,094	$ -		$ -		$ -	$ -
2017	8,516,878	141,164	8,375,714	8,446,296	1,420,709	1,420,709	$ -		$ -		$ -	$ -
2018	8,375,714	141,164	8,234,550	8,305,132	1,399,324	1,399,324	$ -		$ -		$ -	$ -
2019	8,234,550	141,164	8,093,387	8,163,968	1,377,938	1,377,938	$ -		$ -		$ -	$ -
2020	8,093,387	141,164	7,952,223	8,022,805	1,356,553	1,356,553	$ -		$ -		$ -	$ -
2021	7,952,223	141,164	7,811,059	7,881,641	1,335,168	1,335,168	$ -		$ -		$ -	$ -
2022	7,811,059	141,164	7,669,895	7,740,477	1,313,783	1,313,783	$ -		$ -		$ -	$ -
2023	7,669,895	141,164	7,528,732	7,599,314	1,292,398	1,292,398	$ -		$ -		$ -	$ -
2024	7,528,732	141,164	7,387,568	7,458,150	1,271,013	1,271,013	$ -		$ -		$ -	$ -
2025	7,387,568	141,164	7,246,404	7,316,986	1,249,627	1,249,627	$ -		$ -		$ -	$ -
2026	7,246,404	141,164	7,105,241	7,175,822	1,228,242	1,228,242	$ -		$ -		$ -	$ -
2027	7,105,241	141,164	6,964,077	7,034,659	1,206,857	1,206,857	$ -		$ -		$ -	$ -
2028	6,964,077	141,164	6,822,913	6,893,495	1,185,472	1,185,472	$ -		$ -		$ -	$ -
2029	6,822,913	141,164	6,681,749	6,752,331	1,164,087	1,164,087	$ -		$ -		$ -	$ -
2030	6,681,749	141,164	6,540,586	6,611,167	1,142,702	1,142,702	$ -		$ -		$ -	$ -
2031	6,540,586	141,164	6,399,422	6,470,004	1,121,317	1,121,317	$ -		$ -		$ -	$ -
2032	6,399,422	141,164	6,258,258	6,328,840	1,099,931	1,099,931	$ -		$ -		$ -	$ -
2033	6,258,258	141,164	6,117,094	6,187,676	1,078,546	1,078,546	$ -		$ -		$ -	$ -
2034	6,117,094	141,164	5,975,931	6,046,513	1,057,161	1,057,161	$ -		$ -		$ -	$ -
2035	5,975,931	141,164	5,834,767	5,905,349	1,035,776	1,035,776	$ -		$ -		$ -	$ -
2036	5,834,767	141,164	5,693,603	5,764,185	1,014,391	1,014,391	$ -		$ -		$ -	$ -
2037	5,693,603	141,164	5,552,440	5,623,021	993,006	993,006	$ -		$ -		$ -	$ -
2038	5,552,440	141,164	5,411,276	5,481,858	971,620	971,620	$ -		$ -		$ -	$ -
2039	5,411,276	141,164	5,270,112	5,340,694	950,235	950,235	$ -		$ -		$ -	$ -
2040	5,270,112	141,164	5,128,948	5,199,530	928,850	928,850	$ -		$ -		$ -	$ -
2041	5,128,948	141,164	4,987,785	5,058,367	907,465	907,465	$ -		$ -		$ -	$ -
2042	4,987,785	141,164	4,846,621	4,917,203	886,080	886,080	$ -		$ -		$ -	$ -
2043	4,846,621	141,164	4,705,457	4,776,039	864,695	864,695	$ -		$ -		$ -	$ -
2044	4,705,457	141,164	4,564,294	4,634,875	843,310	843,310	$ -		$ -		$ -	$ -
2045	4,564,294	141,164	4,423,130	4,493,712	821,924	821,924	$ -		$ -		$ -	$ -
2046	4,423,130	141,164	4,281,966	4,352,548	800,539	800,539	$ -		$ -		$ -	$ -
2047	4,281,966	141,164	4,140,802	4,211,384	779,154	779,154	$ -		$ -		$ -	$ -
2048	4,140,802	141,164	3,999,639	4,070,221	757,769	757,769	$ -		$ -		$ -	$ -
2049	3,999,639	141,164	3,858,475	3,929,057	736,384	736,384	$ -		$ -		$ -	$ -
2050	3,858,475	141,164	3,717,311	3,787,893	714,999	714,999	$ -		$ -		$ -	$ -
2051	3,717,311	141,164	3,576,148	3,646,729	693,613	693,613	$ -		$ -		$ -	$ -
2052	3,576,148	141,164	3,434,984	3,505,566	672,228	672,228	$ -		$ -		$ -	$ -
2053	3,434,984	141,164	3,293,820	3,364,402	650,843	650,843	$ -		$ -		$ -	$ -
2054	3,293,820	141,164	3,152,656	3,223,238	629,458	629,458	$ -		$ -		$ -	$ -
2055	3,152,656	141,164	3,011,493	3,082,075	608,073	608,073	$ -		$ -		$ -	$ -
2056	3,011,493	141,164	2,870,329	2,940,911	586,688	586,688	$ -		$ -		$ -	$ -
2057	2,870,329	141,164	2,729,165	2,799,747	565,303	565,303	$ -		$ -		$ -	$ -
2058	2,729,165	141,164	2,588,002	2,658,583	543,917	543,917	$ -		$ -		$ -	$ -
2059	2,588,002	141,164	2,446,838	2,517,420	522,532	522,532	$ -		$ -		$ -	$ -
2060	2,446,838	141,164	2,305,674	2,376,256	501,147	501,147	$ -		$ -		$ -	$ -
2061	2,305,674	141,164	2,164,510	2,235,092	479,762	479,762	$ -		$ -		$ -	$ -
2062	2,164,510	141,164	2,023,347	2,093,928	458,377	458,377	$ -		$ -		$ -	$ -
2063	2,023,347	141,164	1,882,183	1,952,765	436,992	436,992	$ -		$ -		$ -	$ -
2064	1,882,183	141,164	1,741,019	1,811,601	415,607	415,607	$ -		$ -		$ -	$ -
2065	1,741,019	141,164	1,599,855	1,670,437	394,221	394,221	$ -		$ -		$ -	$ -
2066	1,599,855	141,164	1,458,692	1,529,274	372,836	372,836	$ -		$ -		$ -	$ -
2067	1,458,692	141,164	1,317,528	1,388,110	351,451	351,451	$ -		$ -		$ -	$ -
2068	1,317,528	141,164	1,176,364	1,246,946	330,066	330,066	$ -		$ -		$ -	$ -
2069	1,176,364	141,164	1,035,201	1,105,782	308,681	308,681	$ -		$ -		$ -	$ -
2070	1,035,201	141,164	894,037	964,619	287,296	287,296	$ -		$ -		$ -	$ -
2071	894,037	141,164	752,873	823,455	265,910	265,910	$ -		$ -		$ -	$ -
2072	752,873	141,164	611,709	682,291	244,525	244,525	$ -		$ -		$ -	$ -
Project Totals		8,422,769			52,472,618	52,472,618	-					

** 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

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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)

Project Description: **RTEP ID: b1659.14 (Fort Wayne - Marion: Relocate 138 kV line due to new 765 kV build into Sorenson)**

2013	Rev Require	W Incentives	Incentive Amounts
Prior Yr Projected	#N/A	#N/A	#N/A
Prior Yr True-Up	#N/A	#N/A	#N/A
True-Up Adjustment	#N/A	#N/A	#N/A

Details			
Investment	1,624,220	Current Year	2013
Service Year (yyyy)	2014	ROE increase accepted by FERC (Basis Points)	-
Service Month (1-12)	12	FCR w/o incentives, less depreciation	15.15%
Useful life	64	FCR w/incentives approved for these facilities, less dep.	15.15%
CIAC (Yes or No)	No	Annual Depreciation Expense	25,378

TRUE UP OF PROJECT REVENUE REQUIREMENT FOR PRIOR YEAR:

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

Investment Year	Beginning Balance	Depreciation Expense	Ending Balance	Average Balance	RTEP Rev. Req't. w/o Incentives	RTEP Rev. Req't. with Incentives **	Incentive Rev. Requirement ##	RTEP Projected Rev. Req't.From Prior Year WS J w/o Incentives	RTEP Rev Req't True-up w/o Incentives	RTEP Projected Rev. Req't.From Prior Year WS J with Incentives **	RTEP Rev Req't True-up with Incentives **	True-up of Incentive with Incentives **
2014	1,624,220	-	1,624,220	1,624,220	246,056	246,056	$ -		$ -		$ -	$ -
2015	1,624,220	25,378	1,598,842	1,611,531	269,512	269,512	$ -		$ -		$ -	$ -
2016	1,598,842	25,378	1,573,463	1,586,152	265,668	265,668	$ -		$ -		$ -	$ -
2017	1,573,463	25,378	1,548,085	1,560,774	261,823	261,823	$ -		$ -		$ -	$ -
2018	1,548,085	25,378	1,522,706	1,535,395	257,978	257,978	$ -		$ -		$ -	$ -
2019	1,522,706	25,378	1,497,328	1,510,017	254,134	254,134	$ -		$ -		$ -	$ -
2020	1,497,328	25,378	1,471,949	1,484,639	250,289	250,289	$ -		$ -		$ -	$ -
2021	1,471,949	25,378	1,446,571	1,459,260	246,444	246,444	$ -		$ -		$ -	$ -
2022	1,446,571	25,378	1,421,193	1,433,882	242,600	242,600	$ -		$ -		$ -	$ -
2023	1,421,193	25,378	1,395,814	1,408,503	238,755	238,755	$ -		$ -		$ -	$ -
2024	1,395,814	25,378	1,370,436	1,383,125	234,911	234,911	$ -		$ -		$ -	$ -
2025	1,370,436	25,378	1,345,057	1,357,746	231,066	231,066	$ -		$ -		$ -	$ -
2026	1,345,057	25,378	1,319,679	1,332,368	227,221	227,221	$ -		$ -		$ -	$ -
2027	1,319,679	25,378	1,294,300	1,306,990	223,377	223,377	$ -		$ -		$ -	$ -
2028	1,294,300	25,378	1,268,922	1,281,611	219,532	219,532	$ -		$ -		$ -	$ -
2029	1,268,922	25,378	1,243,543	1,256,233	215,687	215,687	$ -		$ -		$ -	$ -
2030	1,243,543	25,378	1,218,165	1,230,854	211,843	211,843	$ -		$ -		$ -	$ -
2031	1,218,165	25,378	1,192,787	1,205,476	207,998	207,998	$ -		$ -		$ -	$ -
2032	1,192,787	25,378	1,167,408	1,180,097	204,154	204,154	$ -		$ -		$ -	$ -
2033	1,167,408	25,378	1,142,030	1,154,719	200,309	200,309	$ -		$ -		$ -	$ -
2034	1,142,030	25,378	1,116,651	1,129,340	196,464	196,464	$ -		$ -		$ -	$ -
2035	1,116,651	25,378	1,091,273	1,103,962	192,620	192,620	$ -		$ -		$ -	$ -
2036	1,091,273	25,378	1,065,894	1,078,584	188,775	188,775	$ -		$ -		$ -	$ -
2037	1,065,894	25,378	1,040,516	1,053,205	184,930	184,930	$ -		$ -		$ -	$ -
2038	1,040,516	25,378	1,015,138	1,027,827	181,086	181,086	$ -		$ -		$ -	$ -
2039	1,015,138	25,378	989,759	1,002,448	177,241	177,241	$ -		$ -		$ -	$ -
2040	989,759	25,378	964,381	977,070	173,397	173,397	$ -		$ -		$ -	$ -
2041	964,381	25,378	939,002	951,691	169,552	169,552	$ -		$ -		$ -	$ -
2042	939,002	25,378	913,624	926,313	165,707	165,707	$ -		$ -		$ -	$ -
2043	913,624	25,378	888,245	900,935	161,863	161,863	$ -		$ -		$ -	$ -
2044	888,245	25,378	862,867	875,556	158,018	158,018	$ -		$ -		$ -	$ -
2045	862,867	25,378	837,488	850,178	154,173	154,173	$ -		$ -		$ -	$ -
2046	837,488	25,378	812,110	824,799	150,329	150,329	$ -		$ -		$ -	$ -
2047	812,110	25,378	786,732	799,421	146,484	146,484	$ -		$ -		$ -	$ -
2048	786,732	25,378	761,353	774,042	142,640	142,640	$ -		$ -		$ -	$ -
2049	761,353	25,378	735,975	748,664	138,795	138,795	$ -		$ -		$ -	$ -
2050	735,975	25,378	710,596	723,285	134,950	134,950	$ -		$ -		$ -	$ -
2051	710,596	25,378	685,218	697,907	131,106	131,106	$ -		$ -		$ -	$ -
2052	685,218	25,378	659,839	672,529	127,261	127,261	$ -		$ -		$ -	$ -
2053	659,839	25,378	634,461	647,150	123,416	123,416	$ -		$ -		$ -	$ -
2054	634,461	25,378	609,083	621,772	119,572	119,572	$ -		$ -		$ -	$ -
2055	609,083	25,378	583,704	596,393	115,727	115,727	$ -		$ -		$ -	$ -
2056	583,704	25,378	558,326	571,015	111,883	111,883	$ -		$ -		$ -	$ -
2057	558,326	25,378	532,947	545,636	108,038	108,038	$ -		$ -		$ -	$ -
2058	532,947	25,378	507,569	520,258	104,193	104,193	$ -		$ -		$ -	$ -
2059	507,569	25,378	482,190	494,880	100,349	100,349	$ -		$ -		$ -	$ -
2060	482,190	25,378	456,812	469,501	96,504	96,504	$ -		$ -		$ -	$ -
2061	456,812	25,378	431,433	444,123	92,659	92,659	$ -		$ -		$ -	$ -
2062	431,433	25,378	406,055	418,744	88,815	88,815	$ -		$ -		$ -	$ -
2063	406,055	25,378	380,677	393,366	84,970	84,970	$ -		$ -		$ -	$ -
2064	380,677	25,378	355,298	367,987	81,126	81,126	$ -		$ -		$ -	$ -
2065	355,298	25,378	329,920	342,609	77,281	77,281	$ -		$ -		$ -	$ -
2066	329,920	25,378	304,541	317,230	73,436	73,436	$ -		$ -		$ -	$ -
2067	304,541	25,378	279,163	291,852	69,592	69,592	$ -		$ -		$ -	$ -
2068	279,163	25,378	253,784	266,474	65,747	65,747	$ -		$ -		$ -	$ -
2069	253,784	25,378	228,406	241,095	61,902	61,902	$ -		$ -		$ -	$ -
2070	228,406	25,378	203,028	215,717	58,058	58,058	$ -		$ -		$ -	$ -
2071	203,028	25,378	177,649	190,338	54,213	54,213	$ -		$ -		$ -	$ -
2072	177,649	25,378	152,271	164,960	50,369	50,369	$ -		$ -		$ -	$ -
2073	152,271	25,378	126,892	139,581	46,524	46,524	$ -		$ -		$ -	$ -
Project Totals		1,497,328			9,569,121	9,569,121	-					

** 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

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

Project Description: **RTEP ID: b2048 (Tanners Creek - Support for Transformer A/B Replacemen)**

2013	Rev Require	W Incentives	Incentive Amounts
Prior Yr Projected	0	0	-
Prior Yr True-Up	119,481	119,481	-
True-Up Adjustment	119,481	119,481	-

Details			
Investment	788,694	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	15.15%
Useful life	64	FCR w/incentives approved for these facilities, less dep.	15.15%
CIAC (Yes or No)	No	Annual Depreciation Expense	12,323

TRUE UP OF PROJECT REVENUE REQUIREMENT FOR PRIOR YEAR:

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

Investment Year	Beginning Balance	Depreciation Expense	Ending Balance	Average Balance	RTEP Rev. Req't. w/o Incentives	RTEP Rev. Req't. with Incentives **	Incentive Rev. Requirement ##	RTEP Projected Rev. Req't.From Prior Year WS J w/o Incentives	RTEP Rev Req't True-up w/o Incentives	RTEP Projected Rev. Req't.From Prior Year WS J with Incentives **	RTEP Rev Req't True-up with Incentives **	True-up of Incentive with Incentives **
2013	788,694	-	788,694	788,694	119,481	119,481	$ -	$ 0	$ 119,481	$ 0	$ 119,481	$ -
2014	788,694	12,323	776,371	782,532	130,871	130,871	$ -		$ -		$ -	$ -
2015	776,371	12,323	764,047	770,209	129,004	129,004	$ -		$ -		$ -	$ -
2016	764,047	12,323	751,724	757,886	127,137	127,137	$ -		$ -		$ -	$ -
2017	751,724	12,323	739,401	745,562	125,270	125,270	$ -		$ -		$ -	$ -
2018	739,401	12,323	727,077	733,239	123,403	123,403	$ -		$ -		$ -	$ -
2019	727,077	12,323	714,754	720,916	121,536	121,536	$ -		$ -		$ -	$ -
2020	714,754	12,323	702,431	708,592	119,669	119,669	$ -		$ -		$ -	$ -
2021	702,431	12,323	690,107	696,269	117,802	117,802	$ -		$ -		$ -	$ -
2022	690,107	12,323	677,784	683,946	115,936	115,936	$ -		$ -		$ -	$ -
2023	677,784	12,323	665,461	671,622	114,069	114,069	$ -		$ -		$ -	$ -
2024	665,461	12,323	653,137	659,299	112,202	112,202	$ -		$ -		$ -	$ -
2025	653,137	12,323	640,814	646,976	110,335	110,335	$ -		$ -		$ -	$ -
2026	640,814	12,323	628,491	634,652	108,468	108,468	$ -		$ -		$ -	$ -
2027	628,491	12,323	616,167	622,329	106,601	106,601	$ -		$ -		$ -	$ -
2028	616,167	12,323	603,844	610,006	104,734	104,734	$ -		$ -		$ -	$ -
2029	603,844	12,323	591,521	597,682	102,867	102,867	$ -		$ -		$ -	$ -
2030	591,521	12,323	579,197	585,359	101,000	101,000	$ -		$ -		$ -	$ -
2031	579,197	12,323	566,874	573,035	99,134	99,134	$ -		$ -		$ -	$ -
2032	566,874	12,323	554,550	560,712	97,267	97,267	$ -		$ -		$ -	$ -
2033	554,550	12,323	542,227	548,389	95,400	95,400	$ -		$ -		$ -	$ -
2034	542,227	12,323	529,904	536,065	93,533	93,533	$ -		$ -		$ -	$ -
2035	529,904	12,323	517,580	523,742	91,666	91,666	$ -		$ -		$ -	$ -
2036	517,580	12,323	505,257	511,419	89,799	89,799	$ -		$ -		$ -	$ -
2037	505,257	12,323	492,934	499,095	87,932	87,932	$ -		$ -		$ -	$ -
2038	492,934	12,323	480,610	486,772	86,065	86,065	$ -		$ -		$ -	$ -
2039	480,610	12,323	468,287	474,449	84,198	84,198	$ -		$ -		$ -	$ -
2040	468,287	12,323	455,964	462,125	82,332	82,332	$ -		$ -		$ -	$ -
2041	455,964	12,323	443,640	449,802	80,465	80,465	$ -		$ -		$ -	$ -
2042	443,640	12,323	431,317	437,479	78,598	78,598	$ -		$ -		$ -	$ -
2043	431,317	12,323	418,994	425,155	76,731	76,731	$ -		$ -		$ -	$ -
2044	418,994	12,323	406,670	412,832	74,864	74,864	$ -		$ -		$ -	$ -
2045	406,670	12,323	394,347	400,509	72,997	72,997	$ -		$ -		$ -	$ -
2046	394,347	12,323	382,024	388,185	71,130	71,130	$ -		$ -		$ -	$ -
2047	382,024	12,323	369,700	375,862	69,263	69,263	$ -		$ -		$ -	$ -
2048	369,700	12,323	357,377	363,539	67,396	67,396	$ -		$ -		$ -	$ -
2049	357,377	12,323	345,054	351,215	65,530	65,530	$ -		$ -		$ -	$ -
2050	345,054	12,323	332,730	338,892	63,663	63,663	$ -		$ -		$ -	$ -
2051	332,730	12,323	320,407	326,569	61,796	61,796	$ -		$ -		$ -	$ -
2052	320,407	12,323	308,084	314,245	59,929	59,929	$ -		$ -		$ -	$ -
2053	308,084	12,323	295,760	301,922	58,062	58,062	$ -		$ -		$ -	$ -
2054	295,760	12,323	283,437	289,599	56,195	56,195	$ -		$ -		$ -	$ -
2055	283,437	12,323	271,114	277,275	54,328	54,328	$ -		$ -		$ -	$ -
2056	271,114	12,323	258,790	264,952	52,461	52,461	$ -		$ -		$ -	$ -
2057	258,790	12,323	246,467	252,629	50,595	50,595	$ -		$ -		$ -	$ -
2058	246,467	12,323	234,144	240,305	48,728	48,728	$ -		$ -		$ -	$ -
2059	234,144	12,323	221,820	227,982	46,861	46,861	$ -		$ -		$ -	$ -
2060	221,820	12,323	209,497	215,659	44,994	44,994	$ -		$ -		$ -	$ -
2061	209,497	12,323	197,174	203,335	43,127	43,127	$ -		$ -		$ -	$ -
2062	197,174	12,323	184,850	191,012	41,260	41,260	$ -		$ -		$ -	$ -
2063	184,850	12,323	172,527	178,688	39,393	39,393	$ -		$ -		$ -	$ -
2064	172,527	12,323	160,203	166,365	37,526	37,526	$ -		$ -		$ -	$ -
2065	160,203	12,323	147,880	154,042	35,659	35,659	$ -		$ -		$ -	$ -
2066	147,880	12,323	135,557	141,718	33,793	33,793	$ -		$ -		$ -	$ -
2067	135,557	12,323	123,233	129,395	31,926	31,926	$ -		$ -		$ -	$ -
2068	123,233	12,323	110,910	117,072	30,059	30,059	$ -		$ -		$ -	$ -
2069	110,910	12,323	98,587	104,748	28,192	28,192	$ -		$ -		$ -	$ -
2070	98,587	12,323	86,263	92,425	26,325	26,325	$ -		$ -		$ -	$ -
2071	86,263	12,323	73,940	80,102	24,458	24,458	$ -		$ -		$ -	$ -
2072	73,940	12,323	61,617	67,778	22,591	22,591	$ -		$ -		$ -	$ -
Project Totals		727,077			4,646,605	4,646,605	-					

** 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 2013 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

Line Number	(A) Issuance		(B) Principle Outstanding	(C) Interest Rate	(D) Annual Expense (See Note S on Projected Template)	(E) Notes
1	**Long Term Debt (FF1.p. 256-257.h)**					
2	Advances From Associated Co.		-	5.375%	-	
3	Reacquired Bonds Rockpoert Series D		(40,000,000)	0.17%	(68,000)	
4	**Installment Purchase Contracts (FF1.p. 256-257.h, a)**					
5	PCRB Lawrenceburg In. - Series I		25,000,000	0.040%	10,000	
6	PCRB Lawrenceburg In. - Series H		52,000,000	0.060%	31,200	
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		-	0.000%	-	
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	Senior Unsecured Notes - Series J		250,000,000	3.200%	8,000,000	
15	Fort Wayne Settlement		19,468,642	6.000%	1,168,119	
16	Multiple Draw Term Loan		103,812,500	1.670%	1,733,669	
17						
18	Issuance Discount, Premium, & Expenses:					
19	Auction Fees	FF1.p. 256 & 257.Lines Described as Fees			-	
20	Allowable Hedge Amortization (See Ln 36 Below)				916,010	
21	Amort of Debt Discount and Expenses	FF1.p. 117.63.c			2,814,644	
22	Amort of Debt Premimums (Enter Negative)	FF1.p. 117.65.c			-	
23	Reacquired Debt:					
24	Amortization of Loss	FF1.p. 117.64.c			1,941,251	
25	Amortization of Gain	FF1.p. 117.66.c			(1,712)	
26	**Total Interest on Long Term Debt**		1,600,281,142	5.73%	91,720,180	
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		-	4.12%	-	
31	**Dividends on Preferred Stock**		-	0.00%	-	
32	Net Total Hedge Gains and Losses (WS M, Ln 34, (E))				916,010	
33	Total Projected Capital Structure Balance for 2014 (Projected TCOS, Ln 165)				3,538,039,838	
34	Financial Hedge Recovery Limit - Five Basis Points of Total Capital				0.0005	
35	Limit of Recoverable Amount				1,769,020	
36	**Recoverable Hedge Amortization (Lesser of Ln 32 or Ln 35)**				**916,010**	

Worksheet M Supporting Calculation of Capital Structure and Weighted Average Cost of Capital
Based on Average of Balances At 12/31/2012 & 12/31/2013

(A) Line	(B)	(C) Balances @ 12/31/2013	(D) Balances @ 12/31/2012	(E) Average
	Development of Average Balance of Common Equity			
1	Proprietary Capital (112.16.c&d)	1,922,153,922	1,803,774,755	1,862,964,339
2	Less Preferred Stock (Ln 54 Below)	0	0	-
3	Less Account 216.1 (112.12.c&d)	(96,036)	(104,879)	(100,458)
4	Less Account 219.1 (112.15.c&d)	(15,508,738)	(28,884,204)	(22,196,471)
5	**Average Balance of Common Equity**	1,937,758,696	1,832,763,838	**1,885,261,267**
	Development of Cost of Long Term Debt Based on Average Outstanding Balance			
6	Bonds (112.18.c&d)	-	-	-
7	Less: Reacquired Bonds (112.19.c&d)	40,000,000	-	20,000,000
8	LT Advances from Assoc. Companies (112.20.c&d)	-	-	-
9	Senior Unsecured Notes (112.21.c&d)	1,640,281,142	1,572,429,608	1,606,355,375
10	Less: Fair Value Hedges (See Note on Ln 12 below)	-	-	-
11	**Total Average Debt**	1,600,281,142	1,572,429,608	**1,586,355,375**

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

13	**Annual Interest Expense for 2013**	
14	Interest on Long Term Debt (256-257.33.i)	92,594,357
15	Less: Total Hedge Gain/Expense Accumulated from p 256-257, col. (i) of FERC Form 1 included in Ln 14 and shown in Ln 33 below.	916,010
16	Plus: Allowed Hedge Recovery From Ln 38 below.	916,010
17	Amort of Debt Discount & Expense (117.63.c)	2,814,644
18	Amort of Loss on Reacquired Debt (117.64.c)	1,941,251
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)**	**97,348,540**
22	**Average Cost of Debt for 2013 (Ln 21/Ln 11)**	**6.14%**

CALCULATION OF RECOVERABLE HEDGE GAINS/LOSSES

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

Line	HEDGE AMOUNTS BY ISSUANCE (FROM p. 256-257 (i) of the FERC Form 1)	Total Hedge (Gain)/Loss for 2013	Less Excludable Amounts (See NOTE on Line 23)	Net Includable Hedge Amount	Remaining Unamortized Balance	Amortization Period Beginning	Amortization Period Ending
24	Senior Unsecured Notes - Series F	877,840		877,840	768,110	November 2004	November 2014
25	Senior Unsecured Notes - Series G	(383,570)		(383,570)	(735,176)	December-05	November-15
26	Senior Unsecured Notes - Series H	421,740		421,740	9,752,745	November-06	February-37
27				-			
28				-			
29				-			
30				-			
31				-			
32				-			
					9,785,679		
33	Total Hedge Amortization	916,010	-				

34	Hedge Gain or Loss Prior to Application of Recovery Limit (Sum of Lines 24 to 32)	916,010
35	Total Average Capital Structure Balance for 2013 (True-UP TCOS, Ln 165)	3,471,616,642
36	Financial Hedge Recovery Limit - Five Basis Points of Total Capital	0.0005
37	Limit of Recoverable Amount	1,735,808
38	**Recoverable Hedge Amortization (Lesser of Ln 34 or Ln 37)**	**916,010**

Development 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)	-	-	
47	4.12% Series - 100 - Monetary Value (Ln 45 * Ln 46)	-	-	-
48	4.12% Series - 100 - Dividend Amount (Ln 44 * Ln 47)	-	-	-
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)	-	-	
52	4.56% Series - 100 - Monetary Value (Ln 50 * Ln 51)	-	-	-
53	4.56% Series - 100 - Dividend Amount (Ln 49 * Ln 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 2013 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)	(D)	(E)	(F)	(G)	(H)	(I)
Line	**Date**	**Property Description**	**Function (T) or (G)** T = Transmission G = General	**Basis**	**Proceeds**	**(Gain) / Loss**	**Functional Allocator**	**Functionalized Proceeds (Gain) / Loss**	**FERC Account**
1						-	0.000%	-	
2						-	0.000%	-	
3						-	0.000%	-	
4				Net (Gain) or Loss for 2013		-		-	

AEP East Companies
Cost of Service Formula Rate Using 2013 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 30,000,000

Allocation of PBOP Settlement Amount for 2013

Line#	Company	Total Company Amount Actual Expense (Including AEPSC Billed OPEB)	Ratio of Company Actual to Total	Allocation of PBOB Recovery Allowance	Labor Allocator for 2013	Actual Expense	Allowable Expense	One Year Functional Expense (Over)/Under
		(A) (Line 14)	(B)=(A)/Total (A)	(C)=(B) * 30000000	(D)	(E)=(A) * (D)	(F)=(C) * (D)	(G)=(E) - (F)
1	APCo	(4,215,559)	48.37%	14,511,689	7.115%	(299,951)	1,032,553	(1,332,504)
2								
3	I&M	(3,395,590)	38.96%	11,689,019	3.672%	(124,685)	429,217	(553,902)
4	KPCo	(1,089,175)	12.50%	3,749,390	10.335%	(112,568)	387,506	(500,074)
5	KNGP	(91,189)	1.05%	313,910	12.878%	(11,743)	40,424	(52,167)
6	OPCo	191,908	-2.20%	(660,626)	6.682%	12,823	(44,141)	56,964
7	WPCo	(115,215)	1.32%	396,617	7.229%	(8,328)	28,670	(36,998)
8	**Sum of Lines 1 to 7**	(8,714,820)		30,000,000		(544,452)	1,874,228	(2,418,680)

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

	APCo	I&M	KPCo	KNGSPT	OPCo	WPCo	AEP East Total
9 Direct Charged PBOP Expense per Actuarial Report	(4,054,293)	(3,376,008)	(1,007,225)	(81,745)	(4,165,372)	(103,680)	(12,788,323)
10 Additional PBOP Ledger Entries (from Company Records)	223,423	257,059	(0)	0	4,866,605	-	
11 Medicare Subsidy	-	-	-	-	-	-	-
12 Net Company Expense (Ln 9 + Ln 10 + Ln 11)	(3,830,870)	(3,118,949)	(1,007,225)	(81,745)	701,233	(103,680)	(7,441,236)
			-				
13 PBOP Expenses From AEP Service Corporation (from Company Records)	(384,689)	(276,641)	(81,950)	(9,444)	(509,325)	(11,535)	(1,273,584)
14 Company PBOP Expense (Ln 12 + Ln 13)	(4,215,559)	(3,395,590)	(1,089,175)	(91,189)	191,908	(115,215)	(8,714,820)

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

		INDIANA			**MICHIGAN**			**FERC WHOLESALE**			**COMPANY**
	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	1.2700%	0.646552	0.8211%	1.1700%	0.139381	0.1631%	1.1700%	0.214067	0.2505%	1.23%
Structures & Improvements	352.0	1.3200%	0.646552	0.8534%	1.2700%	0.139381	0.1770%	1.2700%	0.214067	0.2719%	1.30%
Station Equipment	353.0	1.6900%	0.646552	1.0927%	1.6500%	0.139381	0.2300%	1.6500%	0.214067	0.3532%	1.68%
Towers & Fixtures	354.0	1.6000%	0.646552	1.0345%	1.4400%	0.139381	0.2007%	1.4400%	0.214067	0.3083%	1.54%
Poles & Fixtures	355.0	2.4300%	0.646552	1.5711%	2.3900%	0.139381	0.3331%	2.3900%	0.214067	0.5116%	2.42%
Overhead Conductors	356.0	1.5300%	0.646552	0.9892%	1.4500%	0.139381	0.2021%	1.4500%	0.214067	0.3104%	1.50%
Underground Conduit	357.0	1.5600%	0.646552	1.0086%	1.3900%	0.139381	0.1937%	1.3900%	0.214067	0.2976%	1.50%
Underground Conductors	358.0	1.5500%	0.646552	1.0022%	1.4600%	0.139381	0.2035%	1.4600%	0.214067	0.3125%	1.52%
Trails & Roads	359.0	1.4900%	0.646552	0.9634%	1.4700%	0.139381	0.2049%	1.4700%	0.214067	0.3147%	1.48%

(1) As approved in Indiana Case No. 44075.
(2) As approved in MICHIGAN Case No. U16801.
(3) FERC wholesale formula rate agreements specify that the depreciation rates in the formula rates change upon approval of MPSC rates in the Michigan jurisdiction.
(4) The rates approved for each jurisdiction are updated when approved by that commission. These demand-based allocation factors for all jurisdictions are updated when new rates are approved in one of the jurisdictions. These allocation factors reflect I&M's 12 monthly Coincident Peaks during test year of the most recent rate case.

GENERAL NOTES:

The rates for each AEP company have been approved by their respective regulatory commissions.
I&M falls under the authority of Indiana, Michigan and the FERC. Therefore, I&M's rates are a composite of the jurisdictions under which it operates. Each jurisdictions' rate is multiplied by an allocation factor, and the product for each jurisdiction is added with the other jurisdictions to derive the composite rate for the company.
Per the terms of the settlement in this case, AEP will make a 205 filing whenever a company's rates are changed by their commission(s), or if the methodology to calculate the jurisdictional allocator in multiple-state companies changes. Changes in the allocation factors will not necessitate a 205 filing.