

AEP East Companies  
 Transmission Cost of Service Formula Rate  
 Utilizing Historic Cost Data for 2009 and Projected Net Plant at Year-End 2010

**COLUMBUS SOUTHERN POWER COMPANY**

Line No.			Total	Allocator	Transmission Amount
1	REVENUE REQUIREMENT (w/o incentives)	(In 138)			\$144,467,615
2	REVENUE CREDITS	(Note A) (Worksheet E)	9,661,925	DA 1.00000	\$ 9,661,925
3	REVENUE REQUIREMENT For All Company Facilities	(In 1 less In 2)			<u>\$ 134,805,690</u>

**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)		-	DA 1.00000	\$ -
5	NET PLANT CARRYING CHARGE w/o intra-AEP charges or credits or ROE incentives (Note B)				4.333%
6	Annual Rate	$((\text{In } 1 - \text{In } 105 - \text{In } 106) / ((\text{In } 48 + \text{In } 49 + \text{In } 50 + \text{In } 51 + \text{In } 53) \times 100))$			20.96%
7	Monthly Rate	(In 6 / 12)			1.75%
8	NET PLANT CARRYING CHARGE ON LINE 6, w/o depreciation or ROE incentives (Note B)				
9	Annual Rate	$((\text{In } 1 - \text{In } 105 - \text{In } 106 - \text{In } 111 - \text{In } 112) / ((\text{In } 48 + \text{In } 49 + \text{In } 50 + \text{In } 51 + \text{In } 53) \times 100))$			17.88%
10	NET PLANT CARRYING CHARGE ON LINE 9, w/o Return, income taxes or ROE incentives (Note B)				
11	Annual Rate	$((\text{In } 1 - \text{In } 105 - \text{In } 106 - \text{In } 111 - \text{In } 112 - \text{In } 133 - \text{In } 134) / ((\text{In } 48 + \text{In } 49 + \text{In } 50 + \text{In } 51 + \text{In } 53) \times 100))$			7.51%
12	ADDITIONAL REVENUE REQUIREMENT for projects w/ incentive ROE's (Note B) (Worksheet J)				-
13	<b>REVENUE REQUIREMENT FOR SCHEDULE 1A CHARGES</b>				
14	Total Load Dispatch & Scheduling (Account 561)	Line 85 Below			4,820,077
15	Less: Load Dispatch - Scheduling, System Control and Dispatch Services (321.88.b)				2,853,695
16	Less: Load Dispatch - Reliability, Planning & Standards Development Services (321.92.b)				535,808
17	Total 561 Internally Developed Costs	(Line 14 - Line 15 - Line 16)			<u>1,430,574</u>

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Line No.	(1)	(2)	(3)	(4)	(5)
	<u>RATE BASE CALCULATION</u>	<u>Data Sources</u> <u>(See "General Notes")</u>	<u>TO Total</u> <u>NOTE C</u>	<u>Allocator</u>	<u>Total</u> <u>Transmission</u>
18	GROSS PLANT IN SERVICE				
18	Production	(Worksheet A In 1.C)	2,723,046,857	NA 0.00000	-
19	Less: Production ARO (Enter Negative)	(Worksheet A In 2.C)	(32,807,106)	NA 0.00000	-
20	Transmission	(Worksheet A In 3.C & Ln 142)	619,883,849	DA	610,929,358
21	Less: Transmission ARO (Enter Negative)	(Worksheet A In 4.C & Ln 143)	-	TP 0.98555	-
22	Plus: Transmission Plant-in-Service Additions (Worksheet I, In 21.D)		78,323,180	DA 1.00000	78,323,180
23	Plus: Additional Trans Plant on Transferred Assets (Worksheet I, In 22.D)		-	DA 1.00000	-
24	Distribution	(Worksheet A In 5.C)	1,742,606,724	NA 0.00000	-
25	Less: Distribution ARO (Enter Negative)	(Worksheet A In 6.C)	-	NA 0.00000	-
26	General Plant	(Worksheet A In 7.C)	95,862,102	W/S 0.04162	3,989,617
27	Less: General Plant ARO (Enter Negative)	(Worksheet A In 8.C)	(144,371)	W/S 0.04162	(6,008)
28	Intangible Plant	(Worksheet A In 9.C)	55,521,109	W/S 0.04162	2,310,694
29	TOTAL GROSS PLANT	(sum Ins 18 to 28)	5,282,292,344		695,546,840
30	ACCUMULATED DEPRECIATION AND AMORTIZATION				
31	Production	(Worksheet A In 12.C)	1,012,345,849	NA 0.00000	-
32	Less: Production ARO (Enter Negative)	(Worksheet A In 13.C)	(8,851,871)	NA 0.00000	-
33	Transmission	(Worksheet A In 14.C & 28.C)	234,283,632	TP1= 0.98666	231,158,142
34	Less: Transmission ARO (Enter Negative)	(Worksheet A In 15.C)	-	TP1= 0.98666	-
35	Plus: Transmission Plant-in-Service Additions (Worksheet I, In 21.I)		1,122,969	DA 1.00000	1,122,969
36	Plus: Additional Projected Deprec on Transferred Assets (Worksheet I In 24.D)		-	DA 1.00000	-
37	Plus: Additional Transmission Depreciation for 2010 (In 111)		12,769,913	TP1 0.98666	12,599,554
38	Plus: Additional General & Intangible Depreciation for 2010 (In 113 + In 114)		14,867,268	W/S 0.04162	618,750
39	Plus: Additional Accum Deprec on Transferred Assets (Worksheet I In 23.D)		-	DA 1.00000	-
40	Distribution	(Worksheet A In 16.C)	711,733,120	NA 0.00000	-
41	Less: Distribution ARO (Enter Negative)	(Worksheet A In 17.C)	-	NA 0.00000	-
42	General Plant	(Worksheet A In 18.C)	40,184,056	W/S 0.04162	1,672,392
43	Less: General Plant ARO (Enter Negative)	(Worksheet A In 19.C)	(78,690)	W/S 0.04162	(3,275)
44	Intangible Plant	(Worksheet A In 20.C)	46,772,172	W/S 0.04162	1,946,578
45	TOTAL ACCUMULATED DEPRECIATION	(sum Ins 31 to 44)	2,065,148,418		249,115,110
46	NET PLANT IN SERVICE				
47	Production	(In 18 + In 19 - In 31 - In 32)	1,686,745,773		-
48	Transmission	(In 20 + In 21 - In 33 - In 34)	385,600,217		379,771,216
49	Plus: Transmission Plant-in-Service Additions (In 22 - In 35)		77,200,211		77,200,211
50	Plus: Additional Trans Plant on Transferred Assets (In 23 - In 36)		-		-
51	Plus: Additional Transmission Depreciation for 2010 (-In 37)		(12,769,913)		(12,599,554)
52	Plus: Additional General & Intangible Depreciation for 2010 (-In 38)		(14,867,268)		(618,750)
53	Plus: Additional Accum Deprec on Transferred Assets (Worksheet I) (-In 39)		-		-
54	Distribution	(In 24 + In 25 - In 40 - In 41)	1,030,873,604		-
55	General Plant	(In 26 + In 27 - In 42 - In 43)	55,612,365		2,314,492
56	Intangible Plant	(In 28 - In 44)	8,748,937		364,116
57	TOTAL NET PLANT IN SERVICE	(sum Ins 47 to 56)	3,217,143,926		446,431,729
58	DEFERRED TAX ADJUSTMENTS TO RATE BASE	(Note D)			
59	Account No. 281.1 (enter negative)	(Worksheet B, In 2 & In 5.C)	(19,682,408)	NA	-
60	Account No. 282.1 (enter negative)	(Worksheet B, In 7 & In 10.C)	(530,382,766)	DA	(58,485,184)
61	Account No. 283.1 (enter negative)	(Worksheet B, In 12 & In 15.C)	(137,592,723)	DA	(7,884,200)
62	Account No. 190.1	(Worksheet B, In 17 & In 20.C)	88,624,833	DA	11,558,640
63	Account No. 255 (enter negative)	(Worksheet B, In 24 & In 25.C)	-	DA	-
64	TOTAL ADJUSTMENTS	(sum Ins 59 to 63)	(599,033,064)		(54,810,744)
65	PLANT HELD FOR FUTURE USE	(Worksheet A In 29.C & In 30.C)	12,622,018	DA	3,796,688
66	REGULATORY ASSETS	(Worksheet A In 36. (C))	-	DA	-
67	WORKING CAPITAL	(Note E)			
68	Cash Working Capital	(1/8 * In 88)	1,152,280		1,135,635
69	Transmission Materials & Supplies	(Worksheet C, In 2.(D))	311,327	TP 0.98555	306,830
70	A&G Materials & Supplies	(Worksheet C, In 3.(D))	523,438	W/S 0.04162	21,785
71	Stores Expense	(Worksheet C, In 4.(D))	-	GP(h) 0.11861	-
72	Prepayments (Account 165) - Labor Allocated	(Worksheet C, In 6.G)	128,029,679	W/S 0.04162	5,328,376
73	Prepayments (Account 165) - Gross Plant	(Worksheet C, In 6.F)	1,534,222	GP(h) 0.11861	181,968
74	Prepayments (Account 165) - Transmission Only	(Worksheet C, In 6.E)	-	DA 1.00000	-
75	Prepayments (Account 165) - Unallocable	(Worksheet C, In 6.D)	(108,616,842)	NA 0.00000	-
76	TOTAL WORKING CAPITAL	(sum Ins 68 to 75)	22,934,104		6,974,594
77	IPP CONTRIBUTIONS FOR CONSTRUCTION	(Note F) (Worksheet D, In 7.B)	-	DA 1.00000	-
78	RATE BASE (sum Ins 57, 64, 65, 66, 76, 77)		2,653,666,984		402,392,268

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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
79	OPERATION & MAINTENANCE EXPENSE				
80	Production	321.80.b	955,853,593		
81	Distribution	322.156.b	72,280,291		
82	Customer Related Expense	322.164,171,178.b	53,423,271		
83	Regional Marketing Expenses	322.131.b	3,050,178		
84	Transmission	321.112.b	67,581,274		
85	TOTAL O&M EXPENSES	(sum Ins 79 to 83)	1,152,188,607		
86	Less: Total Account 561	(Note G) (Worksheet F, In 14.C)	4,820,077		
87	Less: Account 565	(Note H) 321.96.b	53,542,955		
88	Less: State Regulatory Deferrals & Amortizations	(Note I) (Worksheet F, In 4.C)	-		
88	Total O&M Allocable to Transmission	(Ins 83 - 85 - 86 - 87)	9,218,242	TP 0.98555	9,085,080
89	Administrative and General	323.197.b (Note J)	69,464,264		
90	Less: Acct. 924, Property Insurance	323.185.b	3,010,064		
91	Acct. 9260039 PBOP Expense	PBOP Worksheet O Line 9 & 10, (Note K)	11,878,606		
92	Acct. 9260057 PBOP Medicare Subsidy	PBOP Worksheet O Line 11, (Note K)	(2,393,921)		
93	PBOP Expense Billed From AEPSC	PBOP Worksheet O Line 13, (Note K)	797,175		
94	Acct. 928, Reg. Com. Exp.	323.189.b	113,326		
95	Acct. 930.1, Gen. Advert. Exp.	323.191.b	1,273,244		
96	Acct. 930.2, Misc. Gen. Exp.	323.192.b	1,352,127		
97	Balance of A & G	(In 89 - sum In 90 to In 96)	53,433,643	W/S 0.04162	2,223,817
98	Plus: Acct. 924, Property Insurance	(In 90)	3,010,064	GP(h) 0.11861	357,013
99	Acct. 928 - Transmission Specific	Worksheet F In 18.(E) (Note L)	-	TP 0.98555	-
100	Acct 930.1 - Only safety related ads -Direct	Worksheet F In 30.(E) (Note L)	-	TP 0.98555	-
101	Acct 930.2 - Misc Gen. Exp. - Trans	Worksheet F In 36.(E) (Note L)	105,300	DA 1.00000	105,300
102	Settlement Approved PBOP Recovery	PBOP Worksheet O, Col. C, Line 2, (Note M)	7,846,390	W/S 0.04162	326,553
103	A & G Subtotal	(sum Ins 97 to 102)	64,395,397		3,012,683
104	O & M EXPENSE SUBTOTAL	(In 88 + In 103)	73,613,639		12,097,763
105	Plus: TEA Settlement in Account 565	Company Records (Note H)	51,308,780	DA 1.00000	51,308,780
106	Plus: Transmission Lease Payments To Affiliates in Acct 565 (Company Records) (Note H)		-	DA 1.00000	-
107	TOTAL O & M EXPENSE	(In 104 + In 105 + In 106)	124,922,419		63,406,543
108	DEPRECIATION AND AMORTIZATION EXPENSE				
109	Production	336.2-6.f	53,707,874	NA 0.00000	-
110	Distribution	336.8.f	59,968,342	NA 0.00000	-
111	Transmission	336.7.f	12,769,913	TP1 0.98666	12,599,554
112	Plus: Transmission Plant-in-Service Additions (Worksheet I In 21.I)		1,122,969	DA 1.00000	1,122,969
113	General	336.10.f	3,179,721	W/S 0.04162	132,335
114	Intangible	336.1.f	11,687,547	W/S 0.04162	486,416
115	TOTAL DEPRECIATION AND AMORTIZATION	(Ins 109+110+111 +112+113+114) (Note N)	142,436,366		14,341,274
116	TAXES OTHER THAN INCOME				
117	Labor Related				
118	Payroll	Worksheet H In 23.(D)	4,832,729	W/S 0.04162	201,130
119	Plant Related				
120	Property	Worksheet H In 23.(C) & In 37.(C)	93,070,919	DA	20,127,918
121	Gross Receipts/Sales & Use	Worksheet H In 23.(F)	74,237,556	NA 0.00000	-
122	Other	Worksheet H In 23.(E)	2,927,756	GP(h) 0.11861	347,250
123	TOTAL OTHER TAXES	(sum Ins 118 to 122)	175,068,960		20,676,299
124	INCOME TAXES	(Note O)			
125	$T=1 - \{[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)\}$		35.62%		
126	$EIT=(T/(1-T)) * (1-(WCLTD/WACC)) =$		35.68%		
127	where WCLTD=(In 162) and WACC = (In 165)				
128	and FIT, SIT & p are as given in Note O.				
129	$GRCF=1 / (1 - T) =$ (from In 125)		1.5533		
130	Amortized Investment Tax Credit (enter negative)	(FF1 p.114, In 19.c)	(1,980,124)		
131	Income Tax Calculation	(In 126 * In 134)	80,492,699		12,205,616
132	ITC adjustment	(In 129 * In 130)	(3,075,718)	NP(h) 0.12074	(371,358)
133	TOTAL INCOME TAXES	(sum Ins 131 to 132)	77,416,981		11,834,257
134	RETURN ON RATE BASE (Rate Base * WACC)	(In 78 * In 165)	225,600,601		34,209,242
135	INTEREST ON IPP CONTRIBUTION FOR CONST. (Note F) (Worksheet D, In 2.(B))		-	DA 1.00000	-
136	(Gains) / Losses on Sales of Plant Held for Future Use (Worksheet N, In 4, Cols. ((F) & (H))		-		-
137	Tax Impact on (Gains) / Losses on Sales of Plant Held for Future Use (In 136 * In126)		-		-
138	TOTAL REVENUE REQUIREMENT		745,445,327		144,467,615
	(sum Ins 107, 115, 123, 133, 134, 135, 136, 137)				

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SUPPORTING CALCULATIONS

In							
No.	TRANSMISSION PLANT INCLUDED IN PJM TARIFF						
139	Total transmission plant	(In 20)					619,883,849
140	Less transmission plant excluded from PJM Tariff (Note P)						-
141	Less transmission plant included in OATT Ancillary Services (Worksheet A, In 23, Col. (C)) (Note Q)						8,954,491
142	Transmission plant included in PJM Tariff	(In 139 - In 140 - In 141)					<u>610,929,358</u>
143	Percent of transmission plant in PJM Tariff	(In 142 / In 139)				<b>TP</b>	<b>0.98555</b>
144	WAGES & SALARY ALLOCATOR (W/S)	(Note R)	Direct Payroll	Payroll Billed from AEP Service Corp.	Total		
145	Production	354.20.b	22,531,209	9,587,297	32,118,506	NA	0.00000
146	Transmission	354.21.b	1,506,733	1,680,059	3,186,792	TP	0.98555
147	Regional Market Expenses	354.22.b	0	0	-	NA	0.00000
148	Distribution	354.23.b	22,483,950	2,417,936	24,901,886	NA	0.00000
149	Other (Excludes A&G)	354.24,25,26.b	6,627,571	8,631,040	15,258,611	NA	0.00000
150	Total	(sum Ins 145 to 149)	<u>53,149,463</u>	<u>22,316,332</u>	<u>75,465,795</u>		
151	Transmission related amount					<b>W/S=</b>	<b>0.04162</b>
152	WEIGHTED AVERAGE COST OF CAPITAL (WACC)						<u>\$</u>
153	Long Term Interest	(Worksheet L, In. 35, col. (D))					89,084,444
154	Preferred Dividends	(Worksheet L, In. 40, col. (D))					-
155	<u>Development of Common Stock:</u>						
156	Proprietary Capital	(FF1 p 112, Ln 16.c)					1,359,835,152
157	Less: Preferred Stock	(FF1 p 112, Ln 3.c)					-
158	Less: Account 216.1	(FF1 p 112, Ln 12.c)					2,064,800
159	Less: Account 219	(FF1 p 112, Ln 15.c)					<u>(49,993,531)</u>
160	Common Stock	(In 156 - In 157 - In 158 - In 159)					<u>1,407,763,883</u>
161			\$	%		Cost (Note S)	Weighted
162	Long Term Debt (Note T) Worksheet L, In 35, col. (B))		<u>1,542,745,000</u>	52.29%		0.0577	0.0302
163	Preferred Stock (In 157)		-	0.00%		-	0.0000
164	Common Stock (In 160)		<u>1,407,763,883</u>	47.71%		11.49%	<u>0.0548</u>
165	Total (Sum Ins 162 to 164)		<u>2,950,508,883</u>			<b>WACC=</b>	<b>0.0850</b>

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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 projected as of December 31, 2010. Other ratebase amounts are as of December 31, 2009.
- 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 Ancillary 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 5 through 14, for descriptions and the Form 1 Source of these accounts' balances.**
- H Removes cost of transmission service provided by others to determine the basis of cash working capital on line 88. To the extent such service is incurred to provide the PJM service at issue, e.g. transmission equalization agreement, such costs are added back on lines 105 and 106 to determine the total O&M collected in the formula. The amounts on lines 105 and 106 are also excluded in the calculation of the FCR percentage calculated on lines 5 through 11. The addbacks on lines 105 and 106 of activity recorded in 565 represents inter-company sales or purchases of transmission capacity necessary to meet each AEP company's transmission load relative to their available transmission capacity.  
**The company records referenced on lines 105 and 106 is the COLUMBUS SOUTHERN 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 seven 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) (In 130) multiplied by (1/1-T). If the applicable tax rates are zero enter 0.  
Inputs Required: FIT = 35.00%  
SIT= 0.96% (State Income Tax Rate or Composite SIT. Worksheet G)  
p = 0.00% (percent of federal income tax deductible for state purposes)
- P Removes plant excluded from the OATT because it does not meet the PJM's definition of Transmission Facilities or is otherwise ineligible to be recovered under the OATT
- Q Removes transmission plant (e.g. step-up transformers) included in the development of OATT ancillary service rates and not already removed for reasons indicated in Note P.
- R Includes functional wages & salaries billed by AEP Service Corporation for support of the operating company.
- S Long Term Debt cost rate = long-term interest (In 153) / long term debt (In 162). Preferred Stock cost rate = preferred dividends (In 154) / preferred outstanding (In 163). Common Stock cost rate (ROE) = 11.49%, the rate accepted by FERC in Docket No. ER08-1329. It includes an additional 50 basis points for PJM RTO membership. **In the Projected & Historic templates, the interest expense on long-term debt is the sum of a full year's interest expense at the coupon rate for each issuance outstanding as of December 31 of the historic year. The projected expense for variable rate debt will be based on the effective rate at December 31. These conventions ensure that the expense used in the projection will reflect a full year, similar to the actual expense that will appear in the subsequent true-up of the projection, and minimize the impact on the true-up of using a partial year interest expense. The projection will reflect the actual historic-year expense recorded for issuance expenses, discounts and premiums, and gains or losses on reacquired debt. Eligible hedging gains or losses will be limited to five basis points of the projected capital structure. Details and calculations are shown on Worksheet L.**
- T This note only applies to Indiana Michigan Power Company.
- U **This note only applies to the true-up template.**

AEP East Companies  
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**COLUMBUS SOUTHERN POWER COMPANY**

Line No.			Total	Allocator	Transmission Amount
166	REVENUE REQUIREMENT (w/o incentives)	(In 303)			\$135,964,507
167	REVENUE CREDITS	(Note A) (Worksheet E)	9,661,925	DA 1.00000	\$ 9,661,925
168	REVENUE REQUIREMENT For All Company Facilities	(In 166 less In 167)			\$ 126,302,582

**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	( (In 166 - In 270 - In 271) / In 213 x 100)			22.29%
172	Monthly Rate	(In 171 / 12)			1.86%
173	NET PLANT CARRYING CHARGE ON LINE 171 , w/o depreciation or ROE incentives (Note B)				
174	Annual Rate	( (In 166 - In 270 - In 271 - In 276) / In 213 x 100)			18.97%
175	NET PLANT CARRYING CHARGE ON LINE 174, w/o Return, income taxes or ROE incentives (Note B)				
176	Annual Rate	( (In 166 - In 270 - In 271 - In 276 - In 298 - In 299) / In 213 x 100)			8.79%
177	Not applicable on this template				

**REVENUE REQUIREMENT FOR SCHEDULE 1A CHARGES**

179	Total Load Dispatch & Scheduling (Account 561)	Line 250 Below			4,820,077
180	Less: Load Dispatch - Scheduling, System Control and Dispatch Services (321.88.b)				2,853,695
181	Less: Load Dispatch - Reliability, Planning & Standards Development Services (321.92.b)				535,808
182	Total 561 Internally Developed Costs	(Line 179 - Line 180 - Line 181)			1,430,574

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COLUMBUS SOUTHERN POWER COMPANY

Line No.	(1)	(2)	(3)	(4)	(5)
	<u>RATE BASE CALCULATION</u>	Data Sources <u>(See "General Notes")</u>	<u>TO Total</u> <u>NOTE C</u>	<u>Allocator</u>	<u>Total</u> <u>Transmission</u>
183	GROSS PLANT IN SERVICE				
183	Production	(Worksheet A In 1.C)	2,723,046,857	NA	-
184	Less: Production ARO (Enter Negative)	(Worksheet A In 2.C)	(32,807,106)	NA	-
185	Transmission	(Worksheet A In 3.C & Ln 307)	619,883,849	DA	610,929,358
186	Less: Transmission ARO (Enter Negative)	(Worksheet A In 4.C & Ln 308)	-	TP	-
187	Plus: Transmission Plant-in-Service Additions (Worksheet I)		N/A	NA	N/A
188	Plus: Additional Trans Plant on Transferred Assets (Worksheet I)		N/A	NA	N/A
189	Distribution	(Worksheet A In 5.C)	1,742,606,724	NA	-
190	Less: Distribution ARO (Enter Negative)	(Worksheet A In 6.C)	-	NA	-
191	General Plant	(Worksheet A In 7.C)	95,862,102	W/S	3,989,617
192	Less: General Plant ARO (Enter Negative)	(Worksheet A In 8.C)	(144,371)	W/S	(6,008)
193	Intangible Plant	(Worksheet A In 9.C)	55,521,109	W/S	2,310,694
194	TOTAL GROSS PLANT	(sum Ins 183 to 193)	5,203,969,164	<b>GP(h)=</b>	<b>0.118606</b>
				<b>GTD=</b>	<b>0.25860</b>
195	ACCUMULATED DEPRECIATION AND AMORTIZATION				
196	Production	(Worksheet A In 12.C)	1,012,345,849	NA	-
197	Less: Production ARO (Enter Negative)	(Worksheet A In 13.C)	(8,851,871)	NA	-
198	Transmission	(Worksheet A In 14.C & 28.C)	234,283,632	TP1=	231,158,142
199	Less: Transmission ARO (Enter Negative)	(Worksheet A In 15.C)	-	TP1=	-
200	Plus: Transmission Plant-in-Service Additions (Worksheet I)		N/A	DA	N/A
201	Plus: Additional Projected Deprec on Transferred Assets (Worksheet I)		N/A	DA	N/A
202	Plus: Additional Transmission Depreciation for 2010 (In 276)		N/A	TP1	N/A
203	Plus: Additional General & Intangible Depreciation for 2010 (In 275 + In 276)		N/A	W/S	N/A
204	Plus: Additional Accum Deprec on Transferred Assets (Worksheet I)		N/A	DA	N/A
205	Distribution	(Worksheet A In 16.C)	711,733,120	NA	-
206	Less: Distribution ARO (Enter Negative)	(Worksheet A In 17.C)	-	NA	-
207	General Plant	(Worksheet A In 18.C)	40,184,056	W/S	1,672,392
208	Less: General Plant ARO (Enter Negative)	(Worksheet A In 19.C)	(78,690)	W/S	(3,275)
209	Intangible Plant	(Worksheet A In 20.C)	46,772,172	W/S	1,946,578
210	TOTAL ACCUMULATED DEPRECIATION	(sum Ins 196 to 209)	2,036,388,268		234,773,837
211	NET PLANT IN SERVICE				
212	Production	(In 183 + In 184 - In 196 - In 197)	1,686,745,773		-
213	Transmission	(In 185 + In 186 - In 198 - In 199)	385,600,217		379,771,216
214	Plus: Transmission Plant-in-Service Additions (In 187 - In 200)		N/A		N/A
215	Plus: Additional Trans Plant on Transferred Assets (In 188 - In 201)		N/A		N/A
216	Plus: Additional Transmission Depreciation for 2010 (-In 202)		N/A		N/A
217	Plus: Additional General & Intangible Depreciation for 2010 (-In 203)		N/A		N/A
218	Plus: Additional Accum Deprec on Transferred Assets (Worksheet I) (-In 204)		N/A		N/A
219	Distribution	(In 189 + In 190 - In 205 - In 206)	1,030,873,604		-
220	General Plant	(In 191 + In 192 - In 207 - In 208)	55,612,365		2,314,492
221	Intangible Plant	(In 193 - In 209)	8,748,937		364,116
222	TOTAL NET PLANT IN SERVICE	(sum Ins 212 to 221)	3,167,580,896	<b>NP(h)=</b>	<b>0.120739</b>
223	DEFERRED TAX ADJUSTMENTS TO RATE BASE	(Note D)			
224	Account No. 281.1 (enter negative)	(Worksheet B, In 2 & In 5.C)	(19,682,408)	NA	-
225	Account No. 282.1 (enter negative)	(Worksheet B, In 7 & In 10.C)	(530,382,766)	DA	(58,485,184)
226	Account No. 283.1 (enter negative)	(Worksheet B, In 12 & In 15.C)	(137,592,723)	DA	(7,884,200)
227	Account No. 190.1	(Worksheet B, In 17 & In 20.C)	88,624,833	DA	11,558,640
228	Account No. 255 (enter negative)	(Worksheet B, In 24 & In 25.C)	-	DA	-
229	TOTAL ADJUSTMENTS	(sum Ins 224 to 228)	(599,033,064)		(54,810,744)
230	PLANT HELD FOR FUTURE USE	(Worksheet A In 29.C & In 30.C)	12,622,018	DA	3,796,688
231	REGULATORY ASSETS	(Worksheet A In 36. (C))	-	DA	-
232	WORKING CAPITAL	(Note E)			
233	Cash Working Capital	(1/8 * In 253)	1,152,280		1,135,635
234	Transmission Materials & Supplies	(Worksheet C, In 2.(D))	311,327	TP	306,830
235	A&G Materials & Supplies	(Worksheet C, In 3.(D))	523,438	W/S	21,785
236	Stores Expense	(Worksheet C, In 4.(D))	-	GP(h)	-
237	Prepayments (Account 165) - Labor Allocated	(Worksheet C, In 6.G)	128,029,679	W/S	5,328,376
238	Prepayments (Account 165) - Gross Plant	(Worksheet C, In 6.F)	1,534,222	GP(h)	181,968
239	Prepayments (Account 165) - Transmission Only	(Worksheet C, In 6.E)	-	DA	-
240	Prepayments (Account 165) - Unallocable	(Worksheet C, In 6.D)	(108,616,842)	NA	-
241	TOTAL WORKING CAPITAL	(sum Ins 233 to 240)	22,934,104		6,974,594
242	IPP CONTRIBUTIONS FOR CONSTRUCTION	(Note F) (Worksheet D, In 7.B)	-	DA	-
243	RATE BASE (sum Ins 222, 229, 230, 231, 241, 242)		2,604,103,954		338,410,362

AEP East Companies  
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Utilizing Historic Cost Data for 2009 with Year-End Rate Base Balances

COLUMBUS SOUTHERN POWER COMPANY

(1)	(2)	(3)	(4)	(5)
EXPENSE, TAXES, RETURN & REVENUE REQUIREMENTS CALCULATION	Data Sources (See "General Notes")	TO Total	Allocator	Total Transmission
Line No.				
OPERATION & MAINTENANCE EXPENSE				
244 Production	321.80.b	955,853,593		
245 Distribution	322.156.b	72,280,291		
246 Customer Related Expense	322 & 323.164,171,178.b	53,423,271		
247 Regional Marketing Expenses	322.131.b	3,050,178		
248 Transmission	321.112.b	67,581,274		
249 TOTAL O&M EXPENSES	(sum Ins 244 to 248)	1,152,188,607		
250 Less: Total Account 561	(Note G) (Worksheet F, In 14.C)	4,820,077		
251 Less: Account 565	(Note H) 321.96.b	53,542,955		
252 Less: Regulatory Deferrals & Amortizations	(Note I) (Worksheet F, In 4.C)	-		
253 Total O&M Allocable to Transmission	(Ins 248 - 250 - 251 - 252)	9,218,242	TP 0.98555	9,085,080
254 Administrative and General	323.197.b (Note J)	69,464,264		
255 Less: Acct. 924, Property Insurance	323.185.b	3,010,064		
256 Acct. 9260039 PBOP Expense	PBOP Worksheet O Line 9 & 10, (Note K)	11,878,606		
257 Acct. 9260057 PBOP Medicare Subsidy	PBOP Worksheet O Line 11, (Note K)	(2,393,921)		
258 PBOP Expense Billed From AEPSC	PBOP Worksheet O Line 13, (Note K)	797,175		
259 Acct. 928, Reg. Com. Exp.	323.189.b	113,326		
260 Acct. 930.1, Gen. Advert. Exp.	323.191.b	1,273,244		
261 Acct. 930.2, Misc. Gen. Exp.	323.192.b	1,352,127		
262 Balance of A & G	(In 254 - sum In 255 to In 261)	53,433,643	W/S 0.04162	2,223,817
263 Plus: Acct. 924, Property Insurance	(In 255)	3,010,064	GP(h) 0.11861	357,013
264 Acct. 928 - Transmission Specific	Worksheet F In 18,(E) (Note L)	-	TP 0.98555	-
265 Acct 930.1 - Only safety related ads -Direct	Worksheet F In 30,(E) (Note L)	-	TP 0.98555	-
266 Acct 930.2 - Misc Gen. Exp. - Trans	Worksheet F In 36,(E) (Note L)	105,300	DA 1.00000	105,300
267 Settlement Approved PBOP Recovery	PBOP Worksheet O, Col. C, Line 2, (Note M)	7,846,390	W/S 0.04162	326,553
268 A & G Subtotal	(sum Ins 262 to 267)	64,395,397		3,012,683
269 O & M EXPENSE SUBTOTAL	(In 253 + In 268)	73,613,639		12,097,763
270 Plus: TEA Settlement in Account 565	Company Records (Note H)	51,308,780	DA 1.00000	51,308,780
271 Plus: Transmission Lease Payments To Affiliates in	Acct 565 (Company Records) (Note H)	-	DA 1.00000	-
272 TOTAL O & M EXPENSE	(In 269 + In 270 + In 271)	124,922,419		63,406,543
273 DEPRECIATION AND AMORTIZATION EXPENSE				
274 Production	336.2-6.f	53,707,874	NA 0.00000	-
275 Distribution	336.8.f	59,968,342	NA 0.00000	-
276 Transmission	336.7.f	12,769,913	TP1 0.98666	12,599,554
277 Plus: Transmission Plant-in-Service Additions (Worksheet I)		N/A		N/A
278 General	336.10.f	3,179,721	W/S 0.04162	132,335
279 Intangible	336.1.f	11,687,547	W/S 0.04162	486,416
280 TOTAL DEPRECIATION AND AMORTIZATION	(Ln 274+275+ 276+277+278+279)	141,313,397		13,218,305
281 TAXES OTHER THAN INCOME	(Note N)			
282 Labor Related				
283 Payroll	Worksheet H In 23.(D)	4,832,729	W/S 0.04162	201,130
284 Plant Related				
285 Property	Worksheet H In 23.(C) & In 37.(C)	93,070,919	DA 0.00000	20,127,918
286 Gross Receipts/Sales & Use	Worksheet H In 23.(F)	74,237,556	NA 0.00000	-
287 Other	Worksheet H In 23.(E)	2,927,756	GP(h) 0.11861	347,250
288 TOTAL OTHER TAXES	(sum Ins 283 to 287)	175,068,960		20,676,299
289 INCOME TAXES	(Note O)			
290 $T=1 - ((1 - SIT) * (1 - FIT)) / (1 - SIT * FIT * p) =$		35.62%		
291 $EIT=(T/(1-T)) * (1-(WCLTD/WACC)) =$		35.68%		
292 where WCLTD=(In 327) and WACC = (In 330)				
293 and FIT, SIT & p are as given in Note O.				
294 $GRCF=1 / (1 - T) =$ (from In 290)		1.5533		
295 Amortized Investment Tax Credit (enter negative)	(FF1 p.114, In 19.c)	(1,980,124)		
296 Income Tax Calculation	(In 291 * In 299)	78,989,322		10,264,876
297 ITC adjustment	(In 294 * In 295)	(3,075,718)	NP(h) 0.12074	(371,358)
298 TOTAL INCOME TAXES	(sum Ins 296 to 297)	75,913,604		9,893,518
299 RETURN ON RATE BASE (Rate Base*WACC)	(In 243 * In 330)	221,387,016		28,769,842
300 INTEREST ON IPP CONTRIBUTION FOR CONST. (Note F) (Worksheet D, In 2.(B))		-	DA 1.00000	-
301 (Gains) / Losses on Sales of Plant Held for Future Use (Worksheet N, In 4, Cols. ((F) & (H))		-		-
302 Tax Impact on Net Loss / (Gain) on Sales of Plant Held for Future Use (In 301 * In 291)		-		-
303 TOTAL REVENUE REQUIREMENT		738,605,396		135,964,507
(sum Ins 272, 280, 288, 298, 299, 300, 301, 302)				

AEP East Companies  
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COLUMBUS SOUTHERN POWER COMPANY

SUPPORTING CALCULATIONS

In										
No.	TRANSMISSION PLANT INCLUDED IN PJM TARIFF									
304	Total transmission plant	(In 185)								619,883,849
305	Less transmission plant excluded from PJM Tariff (Note P)									-
306	Less transmission plant included in OATT Ancillary Services (Worksheet A, In 23, Col. (C)) (Note Q)									8,954,491
307	Transmission plant included in PJM Tariff	(In 304 - In 305 - In 306)								610,929,358
308	Percent of transmission plant in PJM Tariff	(In 307 / In 304)							<b>TP=</b>	<b>0.98555</b>
309	WAGES & SALARY ALLOCATOR (W/S)	(Note R)	Direct Payroll	Payroll Billed from AEP Service Corp.	Total					
310	Production	354.20.b	22,531,209	9,587,297	32,118,506	NA	0.00000			-
311	Transmission	354.21.b	1,506,733	1,680,059	3,186,792	TP	0.98555			3,140,757
312	Regional Market Expenses	354.22.b	0	0	-	NA	0.00000			-
313	Distribution	354.23.b	22,483,950	2,417,936	24,901,886	NA	0.00000			-
314	Other (Excludes A&G)	354.24,25,26.b	6,627,571	8,631,040	15,258,611	NA	0.00000			-
315	Total	(sum Ins 310 to 314)	53,149,463	22,316,332	75,465,795					3,140,757
316	Transmission related amount								<b>W/S=</b>	<b>0.04162</b>
317	WEIGHTED AVERAGE COST OF CAPITAL (WACC)									\$
318	Long Term Interest	(Worksheet L, In. 35, col. (D))								89,084,444
319	Preferred Dividends	(Worksheet L, In. 40, col. (D))								-
320	<u>Development of Common Stock:</u>									
321	Proprietary Capital	(FF1 p 112, Ln 16.c)								1,359,835,152
322	Less: Preferred Stock	(FF1 p 112, Ln 3.c)								-
323	Less: Account 216.1	(FF1 p 112, Ln 12 .c)								2,064,800
324	Less: Account 219	(FF1 p 112, Ln 15.c)								(49,993,531)
325	Common Stock	(In 321 - In 322 - In 323 - In 324)								1,407,763,883
326			\$	%			Cost (Note S)		Weighted	
327	Long Term Debt (Note T) Worksheet L, In 35, col. (B)		1,542,745,000	52.29%			0.0577			0.0302
328	Preferred Stock (In 322)		-	0.00%			-			0.0000
329	Common Stock (In 325)		1,407,763,883	47.71%			11.49%			0.0548
330	Total (Sum Ins 327 to 329)		2,950,508,883						<b>WACC=</b>	<b>0.0850</b>

AEP East Companies  
Transmission Cost of Service Formula Rate  
Utilizing Historic Cost Data for 2009 with Year-End Rate Base Balances

COLUMBUS SOUTHERN 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 historic as of December 31, 2009.**
- 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 Ancillary 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 25  
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 inte expense is included on line 300.
- G **Removes from the cost of service the Load Scheduling and Dispatch expenses booked to accounts 561.1 through 561.8. Expenses recorded in these accounts, with the exception of 561.4 & 561.8 (lines 180 & 181 above) are recovered in Schedule 1A, OATT ancillary services rates. See Worksheet F, lines 5 through 14, for descriptions and the Form 1 Source of these accounts' balances.**
- H Removes cost of transmission service provided by others to determine the basis of cash working capital on line 253. To the extent such service is incurred to provide the PJM service at issue, e.g. transmission equalization agreement, such costs are added back on lines 270 and 271 to determine the total O&M collected in the formula. The amounts on lines 270 and 271 are also excluded in the calculation of the FCR percentage calculated on lines 170 through 176.  
The addbacks on lines 270 and 271 of activity recorded in 565 represents inter-company sales or purchases of transmission capacity necessary to meet each AEP company's transmission load relative to their available transmission capacity.  
**The company records referenced on lines 270 and 271 is the COLUMBUS SOUTHERN 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. Act 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 seven 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)  
(In 295) multiplied by (1/1-T) . If the applicable tax rates are zero enter 0.  
Inputs Required:
- |       |        |   |
|-------|--------|---|
| FIT = | 35.00% |   |
| SIT=  | 0.96%  | (State Income Tax Rate or Composite SIT, Worksheet G)         |
| p =   | 0.00%  | (percent of federal income tax deductible for state purposes) |
- P Removes plant excluded from the OATT because it does not meet the PJM's definition of Transmission Facilities or is otherwise ineligible to be recovered under the OATT.
- Q Removes transmission plant (e.g. step-up transformers) included in the development of OATT ancillary service rates and not already removed for reasons indicated in Note P.
- R Includes functional wages & salaries billed by AEP Service Corporation for support of the operating company.
- S Long Term Debt cost rate = long-term interest (In 318) / long term debt (In 327). Preferred Stock cost rate = preferred dividends (In 319) / preferred outstanding (In 328). Common Stock cost rate (ROE) = 11.49%, the rate accepted by FERC in Docket No. ER08-1329. It includes an additional 50 basis points for remaining a member of the PJM RTO.  
**In the Projected & Historic templates, the interest expense on long-term debt is the sum of a full year's interest expense at the coupon rate for each issuance outstanding as of December 31 of the historic year. The projected expense for variable rate debt will be based on the effective rate at December 31. These conventions ensure that the expense used in the projection will reflect a full year, similar to the actual expense that will appear in the subsequent true-up of the projection, and minimize the impact on the true-up of using a partial year interest expense. The projection will reflect the actual historic-year expense recorded for issuance expenses, discounts and premiums, and gains or losses on reacquired debt. Eligible hedging gains or losses will be limited to five basis points of the projected capital structure. Details and calculations are shown on Worksheet L.**
- T This note only applies to Indiana Michigan Power Company.
- U **This note only applies to the true-up template**

AEP East Companies  
 Transmission Cost of Service Formula Rate  
 Utilizing Actual Cost Data for 2009 with Average Ratebase Balances

**COLUMBUS SOUTHERN POWER COMPANY**

Line No.			Total	Allocator	Transmission Amount
1	REVENUE REQUIREMENT (w/o incentives)	(In 138)			\$134,592,329
2	REVENUE CREDITS	(Note A) (Worksheet E)	9,661,925	DA 1.00000	\$ 9,661,925
3	REVENUE REQUIREMENT For All Company Facilities	(In 1 less In 2)			\$ 124,930,404

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

4	Revenue Requirement for PJM Schedule 12 Facilities (w/o incentives) (Worksheet K)		-	DA 1.00000	\$ -
5	NET PLANT CARRYING CHARGE w/o intra-AEP charges or credits or ROE incentives (Note B)				
6	Annual Rate	( (In 1 - In 105 - In 106) / In 48 x 100)			23.05%
7	Monthly Rate	(In 6 / 12)			1.92%
8	NET PLANT CARRYING CHARGE ON LINE 6, w/o depreciation or ROE incentives (Note B)				
9	Annual Rate	( (In 1 - In 105 - In 106 - In 111) / In 48 x 100)			19.55%
10	NET PLANT CARRYING CHARGE ON LINE 9, w/o Return, income taxes or ROE incentives (Note B)				
11	Annual Rate	( (In 1 - In 105 - In 106 - In 111 - In 133 - In 134) / In 48 x 100)			9.25%
12	ADDITIONAL REVENUE REQUIREMENT for projects w/ incentive ROE's (Note B) (Worksheet K)				-
13	<b>REVENUE REQUIREMENT FOR SCHEDULE 1A CHARGES</b>				
14	Total Load Dispatch & Scheduling (Account 561)	Line 85 Below			4,820,077
15	Less: Load Dispatch - Scheduling, System Control and Dispatch Services (321.88.b)				2,853,695
16	Less: Load Dispatch - Reliability, Planning & Standards Development Services (321.92.b)				535,808
17	Total 561 Internally Developed Costs	(Line 14 - Line 15 - Line 16)			1,430,574

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COLUMBUS SOUTHERN POWER COMPANY

Line No.	(1)	(2)	(3)	(4)	(5)
	<b>RATE BASE CALCULATION</b>	<b>Data Sources (See "General Notes")</b>	<b>TO Total NOTE C</b>	<b>Allocator</b>	<b>Total Transmission</b>
18	GROSS PLANT IN SERVICE				
18	Production	(Worksheet A In 1.E)	2,564,777,116	NA	0.00000
19	Less: Production ARO (Enter Negative)	(Worksheet A In 2.E)	(20,560,029)	NA	0.00000
20	Transmission	(Worksheet A In 3.E & Ln 142)	595,181,041	DA	587,870,298
21	Less: Transmission ARO (Enter Negative)	(Worksheet A In 4.E & Ln 143)	-	TP	0.98772
22	Plus: Transmission Plant-in-Service Additions (Worksheet I)		N/A	NA	0.00000
23	Plus: Additional Trans Plant on Transferred Assets (Worksheet I)		N/A	NA	0.00000
24	Distribution	(Worksheet A In 5.E)	1,682,737,251	NA	0.00000
25	Less: Distribution ARO (Enter Negative)	(Worksheet A In 6.E)	-	NA	0.00000
26	General Plant	(Worksheet A In 7.E)	93,186,742	W/S	0.04171
27	Less: General Plant ARO (Enter Negative)	(Worksheet A In 8.E)	(144,371)	W/S	0.04171
28	Intangible Plant	(Worksheet A In 9.E)	64,869,314	W/S	0.04171
29	TOTAL GROSS PLANT	(sum Ins 18 to 28)	4,980,047,063	<b>GP(h)=</b>	<b>0.11937</b>
				<b>GTD=</b>	<b>0.00000</b>
30	ACCUMULATED DEPRECIATION AND AMORTIZATION				
31	Production	(Worksheet A In 12.E)	1,000,084,315	NA	0.00000
32	Less: Production ARO (Enter Negative)	(Worksheet A In 13.E)	(7,513,708)	NA	0.00000
33	Transmission	(Worksheet A In 14.E & 28.E)	228,732,893	TP1=	0.99048
34	Less: Transmission ARO (Enter Negative)	(Worksheet A In 15.E)	-	TP1=	0.99048
35	Plus: Transmission Plant-in-Service Additions (Worksheet I)		N/A	DA	1.00000
36	Plus: Additional Projected Deprec on Transferred Assets (Worksheet I)		N/A	DA	1.00000
37	Plus: Additional Transmission Depreciation for 2010 (In 111)		N/A	TP1	0.99048
38	Plus: Additional General & Intangible Depreciation for 2010 (In 110 + In 111)		N/A	W/S	0.04171
39	Plus: Additional Accum Deprec on Transferred Assets (Worksheet I)		N/A	DA	1.00000
40	Distribution	(Worksheet A In 16.E)	697,209,486	NA	0.00000
41	Less: Distribution ARO (Enter Negative)	(Worksheet A In 17.E)	-	NA	0.00000
42	General Plant	(Worksheet A In 18.E)	39,417,663	W/S	0.04171
43	Less: General Plant ARO (Enter Negative)	(Worksheet A In 19.E)	(76,862)	W/S	0.04171
44	Intangible Plant	(Worksheet A In 20.E)	51,950,718	W/S	0.04171
45	TOTAL ACCUMULATED DEPRECIATION	(sum Ins 31 to 44)	2,009,804,504		
46	NET PLANT IN SERVICE				
47	Production	(In 18 + In 19 - In 31 - In 32)	1,551,646,481		-
48	Transmission	(In 20 + In 21 - In 33 - In 34)	366,448,148		361,314,447
49	Plus: Transmission Plant-in-Service Additions (In 22 - In 35)		N/A		N/A
50	Plus: Additional Trans Plant on Transferred Assets (In 23 - In 36)		N/A		N/A
51	Plus: Additional Transmission Depreciation for 2010 (-In 37)		N/A		N/A
52	Plus: Additional General & Intangible Depreciation for 2010 (-In 38)		N/A		N/A
53	Plus: Additional Accum Deprec on Transferred Assets (Worksheet I) (-In 39)		N/A		N/A
54	Distribution	(In 24 + In 25 - In 40 - In 41)	985,527,766		-
55	General Plant	(In 26 + In 27 - In 42 - In 43)	53,701,570		2,239,871
56	Intangible Plant	(In 28 - In 44)	12,918,596		538,829
57	TOTAL NET PLANT IN SERVICE	(sum Ins 47 to 56)	2,970,242,559	<b>NP(h)=</b>	<b>0.12258</b>
					364,093,147
58	DEFERRED TAX ADJUSTMENTS TO RATE BASE	(Note D)	-		-
59	Account No. 281.1 (enter negative)	(Worksheet B, In 2 & In 5.E)	(13,558,704)	NA	-
60	Account No. 282.1 (enter negative)	(Worksheet B, In 7 & In 10.E)	(489,128,606)	DA	(51,513,703)
61	Account No. 283.1 (enter negative)	(Worksheet B, In 12 & In 15.E)	(128,924,240)	DA	(7,935,668)
62	Account No. 190.1	(Worksheet B, In 17 & In 20.E)	103,296,736	DA	11,637,751
63	Account No. 255 (enter negative)	(Worksheet B, In 24 & In 25.E)	-	DA	-
64	TOTAL ADJUSTMENTS	(sum Ins 59 to 63)	(528,314,814)		(47,811,620)
65	PLANT HELD FOR FUTURE USE	(Worksheet A In 29.E & In 30.E)	12,083,743	DA	3,668,193
66	REGULATORY ASSETS	(Worksheet A In 36. (E))	-	DA	-
67	WORKING CAPITAL	(Note E)			
68	Cash Working Capital	(1/8 - In 88)	1,152,280		1,138,127
69	Transmission Materials & Supplies	(Worksheet C, In 2.F)	258,907	TP	0.98772
70	A&G Materials & Supplies	(Worksheet C, In 3.F)	348,886	W/S	0.04171
71	Stores Expense	(Worksheet C, In 4.(D))	-	GP(h)	0.11937
72	Prepayments (Account 185) - Labor Allocated	(Worksheet C, In 8.G)	131,759,043	W/S	0.04171
73	Prepayments (Account 185) - Gross Plant	(Worksheet C, In 8.F)	1,511,914	GP(h)	0.11937
74	Prepayments (Account 185) - Transmission Only	(Worksheet C, In 8.E)	-	DA	1.00000
75	Prepayments (Account 185) - Unallocable	(Worksheet C, In 8.D)	(112,278,839)	NA	0.00000
76	TOTAL WORKING CAPITAL	(sum Ins 68 to 75)	22,752,190		7,084,495
77	IPP CONTRIBUTIONS FOR CONSTRUCTION	(Note F) (Worksheet D, In 8 (B))	-	DA	1.00000
78	RATE BASE (sum Ins 57, 64, 65, 66, 76, 77)		2,476,763,679		327,034,216

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COLUMBUS SOUTHERN 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
	<b>OPERATION &amp; MAINTENANCE EXPENSE</b>				
79	Production	321.80.b	955,853,593		
80	Distribution	322.156.b	72,280,291		
81	Customer Related Expense	322.164,171,178.b	53,423,271		
82	Regional Marketing Expenses	322.131.b	3,050,178		
83	Transmission	321.112.b	67,581,274		
84	TOTAL O&M EXPENSES	(sum Ins 79 to 83)	1,152,188,607		
85	Less: Total Account 561	(Note G) (Worksheet F, In 14.C)	4,820,077		
86	Less: Account 565	(Note H) 321.96.b	53,542,955		
87	Less: Regulatory Deferrals & Amortizations	(Note I) (Worksheet F, In 4.C)	-		
88	Total O&M Allocable to Transmission	(Ins 83 - 85 - 86 - 87)	9,218,242	TP 0.98772	9,105,012
89	Administrative and General	323.197.b (Note J)	69,464,264		
90	Less: Acct. 924, Property Insurance	323.185.b	3,010,064		
91	Acct. 9260039 PBOP Expense	PBOP Worksheet O Line 9 & 10, (Note K)	11,878,606		
92	Acct. 9260057 PBOP Medicare Subsidy	PBOP Worksheet O Line 11, (Note K)	(2,393,921)		
93	PBOP Expense Billed From AEPSC	PBOP Worksheet O Line 13, (Note K)	797,175		
94	Acct. 928, Reg. Com. Exp.	323.189.b	113,326		
95	Acct. 930.1, Gen. Advert. Exp.	323.191.b	1,273,244		
96	Acct. 930.2, Misc. Gen. Exp.	323.192.b	1,352,127		
97	Balance of A & G	(In 89 - sum In 90 to In 96)	53,433,643	W/S 0.04171	2,228,696
98	Plus: Acct. 924, Property Insurance	(In 90)	3,010,064	GP(h) 0.11937	359,304
99	Acct. 928 - Transmission Specific	Worksheet F In 18.(E) (Note L)	-	TP 0.98555	-
100	Acct 930.1 - Only safety related ads -Direct	Worksheet F In 30.(E) (Note L)	-	TP 0.98555	-
101	Acct 930.2 - Misc Gen. Exp. - Trans	Worksheet F In 36.(E) (Note L)	105,300	DA 1.00000	105,300
102	Settlement Approved PBOP Recovery	PBOP Worksheet O, Col. C, Line 2, (Note M)	7,846,390	W/S 0.04171	327,270
103	A & G Subtotal	(sum Ins 97 to 102)	64,395,397		3,020,570
104	O & M EXPENSE SUBTOTAL	(In 88 + In 103)	73,613,639		12,125,582
105	Plus: TEA Settlement in Account 565	Company Records (Note H)	51,308,780	DA 1.00000	51,308,780
106	Plus: Transmission Lease Payments To Affiliates in Acct 565 (Company Records) (Note H)	Acct 565 (Company Records) (Note H)	-	DA 1.00000	-
107	TOTAL O & M EXPENSE	(In 104 + In 105 + In 106)	124,922,419		63,434,362
108	<b>DEPRECIATION AND AMORTIZATION EXPENSE</b>				
109	Production	336.2-6.f	53,707,874	NA 0.00000	-
110	Distribution	336.8.f	59,968,342	NA 0.00000	-
111	Transmission	336.7.f	12,769,913	TP1 0.99048	12,648,371
112	Plus: Transmission Plant-in-Service Additions (Worksheet I)		N/A		N/A
113	General	336.10.f	3,179,721	W/S 0.04171	132,625
114	Intangible	336.1.f	11,687,547	W/S 0.04171	487,483
115	TOTAL DEPRECIATION AND AMORTIZATION	(Ln 109+110+ 111+112+113+114) (Note N)	141,313,397		13,268,479
116	<b>TAXES OTHER THAN INCOME</b>				
117	Labor Related				
118	Payroll	Worksheet H In 23.(D)	4,832,729	W/S 0.04171	201,571
119	Plant Related				
120	Property	Worksheet H In 23.(C) & In 37.(C)	93,070,919	DA	20,127,918
121	Gross Receipts/Sales & Use	Worksheet H In 23.(F)	74,237,556	NA 0.00000	-
122	Other	Worksheet H In 23.(E)	2,927,756	GP(h) 0.11937	349,479
123	TOTAL OTHER TAXES	(sum Ins 118 to 122)	175,068,960		20,678,969
124	<b>INCOME TAXES</b>				
125	T=1 - (((1 - SIT) * (1 - FIT)) / (1 - SIT * FIT * p)) =	(Note O)	35.62%		
126	EIT=(T/(1-T)) * (1-(WCLTD/WACC)) =		35.50%		
127	where WCLTD=(In 162) and WACC = (In 165) and FIT, SIT & p are as given in Note O.				
129	GRCF=1 / (1 - T) = (from In 125)		1.5533		
130	Amortized Investment Tax Credit (enter negative)	(FF1 p.114, In 19.c)	(1,980,124)		
131	Income Tax Calculation	(In 126 * In 134)	74,583,867		9,848,124
132	ITC adjustment	(In 129 * In 130)	(3,075,718)	NP(h) 0.12258	(377,022)
133	TOTAL INCOME TAXES	(sum Ins 131 to 132)	71,508,149		9,471,102
134	RETURN ON RATE BASE (Rate Base*WACC)	(In 78 * In 165)	210,081,937		27,739,417
135	INTEREST ON IPP CONTRIBUTION FOR CONST. (Note F) (Worksheet D, In 2.(B))		-	DA 1.00000	-
136	(Gains) / Losses on Sales of Plant Held for Future Use (Worksheet N, In 4, Cols. ((F) & (H))		-		-
137	Tax Impact on Net Loss / (Gain) on Sales of Plant Held for Future Use (In 136 * In126)		-		-
138	TOTAL REVENUE REQUIREMENT (sum Ins 107, 115, 123, 133, 134, 135)		722,894,862		134,592,329

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SUPPORTING CALCULATIONS

In No.	TRANSMISSION PLANT INCLUDED IN PJM TARIFF							
139	Total transmission plant	(In 20)						595,181,041
140	Less transmission plant excluded from PJM Tariff (Note P)							-
141	Less transmission plant included in OATT Ancillary Services (Worksheet A, In 23, Col. (C)) (Note Q)							7,310,743
142	Transmission plant included in PJM Tariff	(In 139 - In 140 - In 141)						587,870,298
143	Percent of transmission plant in PJM Tariff	(In 142 / In 139)					<b>TP</b>	<b>0.98772</b>
144	WAGES & SALARY ALLOCATOR (W/S)	(Note R)	Direct Payroll	Payroll Billed from AEP Service Corp.	Total			
145	Production	354.20.b	22,531,209	9,587,297	32,118,506	NA	0.00000	-
146	Transmission	354.21.b	1,506,733	1,680,059	3,186,792	TP	0.98772	3,147,648
147	Regional Market Expenses	354.22.b	0	0	-	NA	0.00000	-
148	Distribution	354.23.b	22,483,950	2,417,936	24,901,886	NA	0.00000	-
149	Other (Excludes A&G)	354.24,25,26.b	6,627,571	8,631,040	15,258,611	NA	0.00000	-
150	Total	(sum Ins 145 to 149)	53,149,463	22,316,332	75,465,795			3,147,648
151	Transmission related amount						<b>W/S=</b>	<b>0.04171</b>
152	WEIGHTED AVERAGE COST OF CAPITAL (WACC)							\$
153	Long Term Interest	(Worksheet M, In. 21, col. (E))						86,431,239
154	Preferred Dividends	(Worksheet M, In. 56, col. (E))						-
155	Development of Common Stock:							Average
156	Proprietary Capital	(Worksheet M, In. 1, col. (E))						1,304,637,514
157	Less: Preferred Stock	(Worksheet M, In. 2, col. (E))						-
158	Less: Account 216.1	(Worksheet M, In. 3, col. (E))						6,133,396
159	Less: Account 219	(Worksheet M, In. 4, col. (E))						(48,422,196)
160	Common Stock	(In 156 - In 157 - In 158 - In 159)						1,346,926,314
161		Average \$						
162	Long Term Debt (Note T) W/S M, In 11, In 22, col. (E))	1,496,622,500					0.0578	0.0304
163	Preferred Stock (In 157)	-	52.63%	0.00%			-	0.0000
164	Common Stock (In 160)	1,346,926,314	0.00%	0.00%			11.49%	0.0544
165	Total (Sum Ins 162 to 164)	2,843,548,814	47.37%	0.00%			<b>WACC=</b>	<b>0.0848</b>
166	Capital Structure Equity Limit (Note U)	51.0%						

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<b>Letter</b>	<b>Notes</b>						
	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, 2008 and December 31, 2009.						
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. <b>The company will not include the ADIT portion of deferred hedge gains and losses in rate base.</b>						
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 Ancillary 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 5 through 14, for descriptions and the Form 1 Source of these accounts' balances.						
H	Removes cost of transmission service provided by others to determine the basis of cash working capital on line 88. To the extent such service is incurred to provide the PJM service at issue, e.g. transmission equalization agreement, such costs are added back on lines 105 and 106 to determine the total O&M collected in the formula. The amounts on lines 105 and 106 are also excluded in the calculation of the FCR percentage calculated on lines 5 through 11. The addbacks on lines 105 and 106 of activity recorded in 565 represents inter-company sales or purchases of transmission capacity necessary to meet each AEP company's transmission load relative to their available transmission capacity. <b>The company records referenced on lines 105 and 106 is the COLUMBUS SOUTHERN POWER COMPANY general ledger.</b>						
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 "WS" 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 seven 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) (In 130) multiplied by (1/(1-T)). If the applicable tax rates are zero enter 0. Inputs Required: <table border="0" style="margin-left: 20px;"> <tr> <td>FIT =</td> <td>35.00%</td> </tr> <tr> <td>SIT =</td> <td>0.96% (State Income Tax Rate or Composite SIT. Worksheet G))</td> </tr> <tr> <td>p =</td> <td>0.00% (percent of federal income tax deductible for state purposes)</td> </tr> </table>	FIT =	35.00%	SIT =	0.96% (State Income Tax Rate or Composite SIT. Worksheet G))	p =	0.00% (percent of federal income tax deductible for state purposes)
FIT =	35.00%						
SIT =	0.96% (State Income Tax Rate or Composite SIT. Worksheet G))						
p =	0.00% (percent of federal income tax deductible for state purposes)						
P	Removes plant excluded from the OATT because it does not meet the PJM's definition of Transmission Facilities or is otherwise ineligible to be recovered under the OATT.						
Q	Removes transmission plant (e.g. step-up transformers) included in the development of OATT ancillary service rates and not already removed for reasons indicated in Note P.						
R	Includes functional wages & salaries billed by AEP Service Corporation for support of the operating company.						
S	Long Term Debt cost rate = long-term interest (In 153) / long term debt (In 162). Preferred Stock cost rate = preferred dividends (In 154) / preferred outstanding (In 163). Common Stock cost rate (ROE) = 11.49%, the rate accepted by FERC in Docket No. ER08-1329. It includes an additional 50 basis points for PJM RTO membership. <b>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.</b>						
T	This note only applies to Indiana Michigan Power Company.						
U	Per Settlement, equity for Transmission Cost of Service Formula Rate is limited to 51% of Capital Structure. If the percentage of equity exceeds the cap, the excess is included in weighted percentage of long term debt in the capital structure. <b>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.</b>						

AEP East Companies  
 Cost of Service Formula Rate Using 2009 FF1 Balances  
 Worksheet A Supporting Plant Balances  
 COLUMBUS SOUTHERN POWER COMPANY

Line	(A)	(B)	(C)	(D)	(E)
Number	Rate Base Item & Supporting Balance	Source of Data	Balance @ December 31, 2009	Balance @ December 31, 2008	Average Balance for 2009
<b>NOTE: Functional ARO investment and accumulated depreciation balances shown below are included in the total functional balances shown here</b>					
<b>Plant Investment Balances</b>					
1	Production Plant In Service	FF1, page 205 Col.(g) & pg. 204 Col. (b), ln 46	2,723,046,857	2,406,507,374	2,564,777,116
2	Production Asset Retirement Obligation (ARO)	FF1, page 205&204, Col.(g)&(b), Ins 15,24,34,44	32,807,106	8,312,951	20,560,029
3	Transmission Plant In Service	FF1, page 207 Col.(g) & pg. 206 Col. (b), ln 58	619,883,849	570,478,232	595,181,041
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	1,742,606,724	1,622,867,778	1,682,737,251
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	95,862,102	90,511,381	93,186,742
8	General Asset Retirement Obligation	FF1, page 207 Col.(g) & pg. 206 Col. (b), ln 98	144,371	144,371	144,371
9	Intangible Plant In Service	FF1, page 205 Col.(g) & pg. 204 Col. (b), ln 5	55,521,109	74,217,518	64,869,314
10	Total Property Investment Balance	(Sum of Lines: 3, 1, 5, 7, 9)	5,236,920,641	4,764,582,283	5,000,751,462
11	Total ARO Balance (included in total on line 10)	(Sum of Lines: 4, 2, 6, 8)	32,951,477	8,457,322	20,704,400
<b>Accumulated Depreciation &amp; Amortization Balance:</b>					
12	Production Accumulated Depreciator	FF1, page 219, Ins 20-24, Col. (b)	1,012,345,849	987,822,780	1,000,084,315
13	Production ARO Accumulated Depreciator	Company Records - Note 1	8,851,871	6,175,545	7,513,708
14	Transmission Accumulated Depreciator	FF1, page 219, ln 25, Col. (b)	234,283,632	223,182,154	228,732,893
15	Transmission ARO Accumulated Depreciator	Company Records - Note 1	-	-	-
16	Distribution Accumulated Depreciator	FF1, page 219, ln 26, Col. (b)	711,733,120	682,685,851	697,209,486
17	Distribution ARO Accumulated Depreciator	Company Records - Note 1	-	-	-
18	General Accumulated Depreciator	FF1, page 219, ln 28, Col. (b)	40,184,056	38,651,270	39,417,663
19	General ARO Accumulated Depreciator	Company Records - Note 1	78,690	75,034	76,862
20	Intangible Accumulated Amortization	FF1, page 200, ln 21, Col. (b)	46,772,172	57,129,263	51,950,718
21	Total Accumulated Depreciation or Amortization	(Sum of Lines: 14, 12, 16, 18, 20)	2,045,318,829	1,989,471,318	2,017,395,074
22	Total ARO Balance (included in total on line 21)	(Sum of Lines: 15, 13, 17, 19)	8,930,561	6,250,579	7,590,570
<b>Generation Step-Up Units</b>					
23	GSU Investment Amount	Company Records - Note 1	8,954,491	5,666,995	7,310,743
24	GSU Accumulated Depreciator	Company Records - Note 1	3,125,490	1,228,595	2,177,043
25	GSU Net Balance	(Line 23 - Line 24)	5,829,001	4,438,400	5,133,701
<b>Transmission Accumulated Depreciation Net of GSU Accumulated Depreciator</b>					
26	Transmission Accumulated Depreciator	(Line 14 Above)	234,283,632	223,182,154	228,732,893
27	Less: GSU Accumulated Depreciator	(Line 24 Above)	3,125,490	1,228,595	2,177,043
28	Subtotal of Transmission Net of GSU	(Line 26 - Line 27)	231,158,142	221,953,559	226,555,851
<b>Plant Held For Future Use</b>					
29	Plant Held For Future Use	FF1, page 214, ln 47, Col. (d)	12,622,018	11,545,468	12,083,743
30	Transmission Plant Held For Future Use	Company Records - Note 1	3,796,688	3,539,697	3,668,193
<b>Regulatory Assets and Liabilities Approved for Recovery in Ratebase</b>					
31	Note: Regulatory Assets & Liabilities can only be included in ratebase pursuant to a 205 filing with the FERC.				
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 2009 FF1 Balances  
Worksheet B Supporting ADIT and ITC Balances  
COLUMBUS SOUTHERN POWER COMPANY

<u>Line Number</u>	<u>(A) Description</u>	<u>(B) Source</u>	<u>(C) Balance @ December 31, 2009</u>	<u>(D) Balance @ December 31, 2008</u>	<u>(E) Average Balance for 2009</u>
1	<b><u>Account 281</u></b>				
2	Year End Utility Deferrals	FF1, p. 272 - 273, In 8, Col. (k)	19,682,408	7,434,999	13,558,704
3	Less: ARO Related Deferrals	Company Records - Note 1	-	-	-
4	Less: Other Excluded Deferrals	Company Records - Note 1	19,682,408	7,434,999	13,558,704
5	Transmission Related Deferrals	Ln 2 - In 3 - In 4	-	-	-
6	<b><u>Account 282</u></b>				
7	Year End Utility Deferrals	FF1, p. 274 - 275, In 5, Col. (k)	530,382,766	447,874,446	489,128,606
8	Less: ARO Related Deferrals	Company Records - Note 1	27,621,339	19,974,552	23,797,946
9	Less: Other Excluded Deferrals	Company Records - Note 1	444,276,243	383,357,673	413,816,958
10	Transmission Related Deferrals	Ln 7 - In 8 - In 9	58,485,184	44,542,221	51,513,703
11	<b><u>Account 283</u></b>				
12	Year End Utility Deferrals	FF1, p. 276 - 277, In 9, Col. (k)	137,592,723	120,255,756	128,924,240
13	Less: ARO Related Deferrals	Company Records - Note 1	-	-	-
14	Less: Other Excluded Deferrals	Company Records - Note 1	129,708,523	112,268,621	120,988,572
15	Transmission Related Deferrals	Ln 12 - In 13 - In 14	7,884,200	7,987,135	7,935,668
16	<b><u>Account 190</u></b>				
17	Year End Utility Deferrals	FF1, p. 234, In 8, Col. (c)	88,624,833	117,968,638	103,296,736
18	Less: ARO Related Deferrals	Company Records - Note 1	12,857,785	4,807,929	8,832,857
19	Less: Other Excluded Deferrals	Company Records - Note 1	64,208,408	101,443,848	82,826,128
20	Transmission Related Deferrals	Ln 17 - In 18 - In 19	11,558,640	11,716,861	11,637,751
21	<b><u>Account 255</u></b>				
22	Year End ITC Balances	FF1, p. 266-267, In 8, Col. (h)	16,832,959	18,813,083	17,823,021
23	Less: Balances Not Qualified for Ratebase	Company Records - Note 1	16,832,959	18,813,083	17,823,021
24	ITC Balances Includeable Ratebase	Ln 22 - In 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 2009 FF1 Balances  
Worksheet C Supporting Working Capital Rate Base Adjustments  
COLUMBUS SOUTHERN POWER COMPANY

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
<b>Materials &amp; Supplies</b>								
Line Number	Source	Balance @ December 31, 2009	Balance @ December 31, 2008	Average Balance for 2009				
1								
2	Transmission Materials & Supplies	FF1, p. 227, ln 8, Col. (c) & (b)	311,327	206,487	258,907			
3	General Materials & Supplies	FF1, p. 227, ln 11, Col. (c) & (b)	523,438	174,333	348,886			
4	Stores Expense (Undistributed)	FF1, p. 227, ln 16, Col. (c) & (b)	0	0	-			

**Prepayment Balance Summary**

	Average of YE Balance	Excludable Balances	100% Transmission Related	Transmission Plant Related	Transmission Labor Related	Total Included in Ratebase (E)+(F)+(G)	
5							
6	Totals as of December 31, 2009	20,947,059	(108,616,842)	0	1,534,222	128,029,679	129,563,901
7	Totals as of December 31, 2008	21,037,176	(115,940,836)		1,489,606	135,488,406	136,978,012
8	<b>Average Balance</b>	<b>20,992,118</b>	<b>(112,278,839)</b>	<b>-</b>	<b>1,511,914</b>	<b>131,759,043</b>	<b>133,270,957</b>

**Prepayments Account 165 - Balance @ 12/31/2009**

9	Acc. No.	Description	2009 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	894,933	-	-	894,933	-	894,933	Plant Related Insurance Policies
11	165001209	Prepaid Sales/Use Taxes	65,000	-	-	65,000	-	65,000	Prepaid Taxes
12	1650003	Prepaid Rents	0	-	-	-	-	-	-
13	1650004	Prepaid Interest	0	-	-	-	-	-	Gen
14	1650005	Prepaid Employee Benefits	671,661	-	-	-	671,661	671,661	-
15	1650006	Other Prepayments	12,860	12,860	-	-	-	-	Relates to EPRI Dues
16	1650009	Prepaid Carry Cost-Factored AR	121,240	121,240	-	-	-	-	AR Factoring - Retail Only
17	1650010	Prepaid Pension Benefits	127,358,018	-	-	-	127,358,018	127,358,018	Prefunded Pension Expense
18	1650014	FAS 158 Qual Contra Asset	(127,358,018)	(127,358,018)	-	-	-	-	SFAS 158 Offset
19	1650016	FAS 112 ASSETS	552	552	-	-	-	-	SFAS 112 Overfunding Asset
20	1650017	Prepayment-Coal	2,090,319	2,090,319	-	-	-	-	Prepaid Coal
21	1650019	Prepaid Pension Expense - CG&E	2,618,528	2,618,528	-	-	-	-	-
22	1650020	Prepaid Pension Expense - DP&L	6,144,689	6,144,689	-	-	-	-	-
23	1650021	Prepaid Insurance - EIS	574,289	-	-	574,289	-	574,289	-
24	1650024	LT Coal Prepayment	7,763,619	7,763,619	-	-	-	-	-
25	1650025	Reserve - LT Coal Prepayment	(10,631)	(10,631)	-	-	-	-	-
<b>Subtotal - Form 1, p 111.57.c</b>			20,947,059	(108,616,842)	0	1,534,222	128,029,679	129,563,901	

**Prepayments Account 165 - Balance @ 12/31/ 2008**

26	Acc. No.	Description	2008 YE Balance	Excludable Balances	100% Transmission Related	Transmission Plant Related	Transmission Labor Related	Total Included in Ratebase (E)+(F)+(G)	Explanation
27	1650001	Prepaid Insurance	1,406,130	-	-	1,406,130	-	1,406,130	Plant Related Insurance Policies
28	165000207	Prepaid Taxes	83,476	-	-	83,476	-	83,476	Prepaid PSC Fees
29	1650003	Prepaid Rents	0	-	-	-	-	-	-
30	1650004	Prepaid Interest	10,264	10,264	-	-	-	-	Gen
31	1650005	Prepaid Employee Benefits	4,267,936	-	-	-	4,267,936	4,267,936	-
32	1650006	Other Prepayments	20,570	20,570	-	-	-	-	Relates to EPRI Dues
33	1650009	Prepaid Carry Cost-Factored AR	230,077	230,077	-	-	-	-	AR Factoring - Retail Only
34	1650010	Prepaid Pension Benefits	131,220,470	-	-	-	131,220,470	131,220,470	Prefunded Pension Expense
35	1650014	FAS 158 Qual Contra Asset	(130,042,694)	(130,042,694)	-	-	-	-	SFAS 158 Offset
36	1650016	FAS 112 ASSETS	590,947	590,947	-	-	-	-	SFAS 112 Overfunding Asset
37	1650017	Prepayment-Coal	13,250,000	13,250,000	-	-	-	-	Prepaid Coal
<b>Subtotal - Form 1, p 111.57.d</b>			21,037,176	(115,940,836)		1,489,606	135,488,406	136,978,012	

AEP East Companies  
 Cost of Service Formula Rate Using 2009 FF1 Balances  
 Worksheet D Supporting IPP Credits  
 COLUMBUS SOUTHERN POWER COMPANY

<u>Line Number</u>	<u>(A) Description</u>	<u>(B) 2009</u>
1	Net Funds from IPP Customers 12/31/2008 (2009 FORM 1, P269, line 24.b)	-
2	Interest Accrual (Company Records - Note 1)	-
3	Revenue Credits to Generators (Company Records - Note 1)	-
4	<u>Other Adjustments</u>	
5	Accounting Adjustment (Company Records - Note 1)	-
6		-
7	Net Funds from IPP Customers 12/31/2009 (2009 FORM 1, P269, line 24.f)	-
8	Average Balance for Year as Indicated in Column ((In 1 + In 7)/2)	-

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

AEP East Companies  
Cost of Service Formula Rate Using 2009 FF1 Balances  
Worksheet E Supporting Revenue Credits  
COLUMBUS SOUTHERN POWER COMPANY

<u>Line Number</u>	<u>Description</u>	<u>Total Company</u>	<u>Non-Transmission</u>	<u>Transmission</u>
1	Account 450, Forfeited Discounts (FF1 p.300.16.(b); Company Records - Note 1)	2,827,686	2,827,686	-
2	Account 451, Miscellaneous Service Revenues (FF1 p.300.17.(b); Company Records - Note 1)	2,259,332	2,144,602	114,730
3	Account 454, Rent from Electric Property (FF1 p.300.19.(b); Company Records - Note 1)	17,232,044	9,742,098	7,489,946
4	Account 4560015, Associated Business Development- (Company Records - Note 1)	730,355	696,875	33,480
5	Account 456 - Other Electric Revenues - (Company Records - Note 1)	13,531,503	13,531,503	-
6	<b>Subtotal - Other Operating Revenues (Company Total equals (FF1 p. 300.26.(b))</b>	<b>36,580,920</b>	<b>28,942,764</b>	<b>7,638,156</b>
7	Accounts 4470004 & 5, Revenues from Grandfathered Transmission Contracts - (Company Records - Note 1)	2,225,916	202,147	2,023,769
8	<b>Total Other Operating Revenues To Reduce Revenue Requirement</b>	<b>38,806,836</b>	<b>29,144,911</b>	<b>9,661,925</b>

Note 1 The total company data on this worksheet comes from the indicated FF1 source, or COLUMBUS SOUTHERN 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 2009 FF1 Balances  
 Worksheet F Supporting Allocation of Specific O&M or A&G Expenses  
 COLUMBUS SOUTHERN POWER COMPANY

Line Number	(A) Item No.	(B) Description	(C)	(D)	(E)	(F) Explanation
			2009 Expense	100% Non-Transmission	100% Transmission Specific	
<b>Regulatory O&amp;M Deferrals &amp; Amortizations</b>						
1	5660005	Ohio E-TCR Rider Under Recovery	-			
2						
3						
4		<b>Total</b>	0			
<b>Detail of Account 561 Per FERC Form 1</b>						
5	FF1 p 321.84.b	561 - Load Dispatching	0			
6	FF1 p 321.85.b	561.1 - Load Dispatch - Reliability	16,786			
7	FF1 p 321.86.b	561.2 - Load Dispatch - Monitor & Operate Trans System	1,300,071			
8	FF1 p 321.87.b	561.3 - Load Dispatch - Trans Service & Scheduling	2,571			
9	FF1 p 321.88.b	561.4 - Scheduling, System Control & Dispatch	2,853,695			
10	FF1 p 321.89.b	561.5 - Reliability, Planning and Standards Development	111,146			
11	FF1 p 321.90.b	561.6 - Transmission Service Studies	0			
12	FF1 p 321.91.b	561.7 - Generation Interconnection Studies	0			
13	FF1 p 321.92.b	561.8 - Reliability, Planning and Standards Development Servi	535,808			
14		<b>Total of Account 561</b>	4,820,077			
<b>Account 928</b>						
15	9280000	Regulatory Commission Exp	12	12		- Misc Expenditures
16	9280001	Regulatory Commission Exp-Adm	118,910	118,910		- Hearing and Review of Long-Term Forecast
17	9280002	Regulatory Commission Exp-Case	(5,596)	(5,596)		- Misc Expenditures
18		<b>Total</b>	113,326	113,326		-
<b>Account 930.1</b>						
19	9301000	General Advertising Expenses	51,740	51,740		-
20	9301001	Newspaper Advertising Space	32,066	32,066		-
21	9301007	Special Adv Space & Prod Exp	663,497	663,497		-
22	9301008	Direct Mail and Handouts	1,595	1,595		-
23	9301009	Fairs, Shows, and Exhibits	157	157		-
24	9301010	Publicity	25,713	25,713		-
25	9301011	Dedications, Tours, & Openings	45	45		-
26	9301012	Public Opinion Surveys	167,416	167,416		-
27	9301013	Movies Slide Films & Speeches	87,244	87,244		-
28	9301014	Video Communications	1,784	1,784		-
29	9301015	Other Corporate Comm Exp	241,988	241,988		-
30		<b>Total</b>	1,273,245	1,273,245		-
<b>Account 930.2</b>						
31	9302000	Misc General Expenses	440,540	440,540		
32	9302003	Corporate & Fiscal Expenses	81,690	81,690		
33	9302004	Research, Develop&Demonstr Exp	13,272	13,272		
34	9302007	Assoc Business Development Exp	387,851	282,551	105,300	
35	9302019	gridSMART Rider Over/Under Recovery	428,774	428,774		
36		<b>Total</b>	1,352,127	1,246,827	105,300	

AEP East Companies  
Cost of Service Formula Rate Using 2009 FF1 Balances  
Worksheet G Supporting - Development of Composite State Income Tax Rate  
COLUMBUS SOUTHERN POWER COMPANY

State Income Tax Rate - Ohio	0.00%	
Phase-out Factor <b>Note 1</b>	0.00%	
Apportionment Factor - <b>Note 2</b>	83.28%	
Effective Ohio State Tax Rate		0.0000%
Ohio Municipal Income Tax Rate	0.80%	
Apportionment Factor - <b>Note 2</b>	91.44%	
Effective Indiana State Tax Rate		0.7315%
West Virginia Corporate Income Tax Rate	8.50%	
Apportionment Factor - <b>Note 2</b>	1.93%	
Effective West Virginia State Tax Rate		0.1641%
Michigan Business Income Tax Rate	6.04%	
Apportionment Factor - <b>Note 2</b>	0.00%	
Effective State Tax Rate		0.0000%
Kentucky Corporation Income Tax Rate	6.00%	
Apportionment Factor - <b>Note 2</b>	0.43%	
Effective State Tax Rate		0.0258%
Illinois Corporate Income Tax Rate	7.30%	
Apportionment Factor - <b>Note 2</b>	0.46%	
Effective State Tax Rate		0.0336%
Total Effective State Income Tax Rate		<u><u>0.9550%</u></u>

**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 Activities Tax that is included in Schedule H and H-1.

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

AEP East Companies  
 Cost of Service Formula Rate Using 2009 FFI Balances  
 Worksheet H Supporting Taxes Other than Income  
 COLUMBUS SOUTHERN POWER COMPANY

Line No.	(A) Account	(B) Total Company	(C) Property	(D) Labor	(E) Other	(F) Non-Allocable
		<b>NOTE 1</b>				
1	<b>Revenue Taxes</b>					
2	Gross Receipts Tax	5,062,654				5,062,654
3	KWH State Excise Tax	69,162,456				69,162,456
4	<b>Real Estate and Personal Property Taxes</b>					
5	Real and Personal Property - Ohio	93,035,253	93,035,253			
6	Real and Personal Property - Other Jurisdictions	35,666	35,666			
7	<b>Payroll Taxes</b>					
8	Federal Insurance Contribution (FICA )	3,870,326		3,870,326		
9	Federal Unemployment Tax	24,799		24,799		
10	State Unemployment Insurance	51,461		51,461		
11	Payroll Taxes	886,143		886,143		
12	<b>Production Taxes</b>					
13	State Severance Taxes	-				-
14	<b>Miscellaneous Taxes</b>					
15	State Business & Occupation Tax	-				-
16	State Public Service Commission Fees	2,756,472			2,756,472	
17	State Franchise Taxes	150,408			150,408	
18	State Lic/Registration Fee	20,466			20,466	
19	Misc. State and Local Tax	410			410	
20	Sales & Use	7,118				7,118
21	Federal Excise Tax	5,328				5,328
22	Michigan Single Business Tax	-				-
23	Total Taxes by Allocable Basis (Total Company Amount Ties to FFI p.114, Ln 14,(c))	175,068,960	93,070,919	4,832,729	2,927,756	74,237,556

**NOTE 1: The detail of each total company number and its source in the FERC Form 1 is shown on WS H-1.**

<b>Functional Property Tax Allocation</b>							
	Production	Transmission	Distribution	General		Total	
24	Functionalized Net Plant (Hist. TCOS, Lns 212 thru 222)	1,686,745,773	385,600,217	1,030,873,604	55,612,365		3,158,831,959
<b>OHIO JURISDICTION</b>							
25	Percentage of Plant in OHIO JURISDICTION	100.00%	100.00%	100.00%	100.00%		
26	Net Plant in OHIO JURISDICTION (Ln 24 * Ln 25)	1,686,745,773	385,600,217	1,030,873,604	55,612,365		3,158,831,959
27	Less: Net Value of Exempted Generation Plant	389,685,808					
28	Taxable Property Basis (Ln 26 - Ln 27)	1,297,059,965	385,600,217	1,030,873,604	55,612,365		2,769,146,151
29	Relative Valuation Factor	24%	85%	85%	24%		2.18
30	Weighted Net Plant (Ln 28 * Ln 29)	311,294,392	327,760,184	876,242,563	13,346,968		
31	General Plant Allocator (Ln 30 / (Total - General Plant))	20.54%	21.63%	57.83%	-100.00%		
32	Functionalized General Plant (Ln 31 * General Plant)	2,741,928	2,886,962	7,718,078	(13,346,968)		-
33	Weighted OHIO JURISDICTION Plant (Ln 30 + 32)	314,036,320	330,647,146	883,960,641	(0)		1,528,644,107
34	Functional Percentage (Ln 33/Total Ln 33)	20.54%	21.63%	57.83%			
35	Functionalized Expense in OHIO JURISDICTION	19,112,656	20,123,612	53,798,985			93,035,253
36	Total Other Jurisdictions: (Line 6 * Net Plant Allocator)		4,306				35,666
37	Total Func. Property Taxes (Sum Lns 35, 36)	19,112,656	20,127,918	53,798,985			93,070,919

AEP East Companies  
 Cost of Service Formula Rate Using 2008 FF1 Balances  
 Worksheet H-1 Form 1 Source Reference of Company Amounts on WS H  
 COLUMBUS SOUTHERN POWER COMPANY

Line No.	(A)	(B)	(C)	(D)
Annual Tax Expenses by Type (Note 1)	Total Company	FERC FORM 1 Tie-Back	FERC FORM 1 Reference	
1	<b>Revenue Taxes</b>			
2	Gross Receipts Tax	5,062,654	50,421	P.263 In 13 (i)
			5,012,233	P.263 In 14 (i)
3	KWH State Excise Tax	69,162,456	69,162,456	P.263 In 11 (i)
4	<b>Real Estate and Personal Property Taxes</b>			
5	Real and Personal Property - Ohio	93,035,253	55,470	P.263.1 In 1 (i)
			55,470	P.263.1 In 2 (i)
			1,303,169	P.263.1 In 3 (i)
			91,293,930	P.263.1 In 4 (i)
			(66,933)	P.263.1 In 8 (i)
			27,428	P.263.1 In 9 (i)
			43,317	P.263.1 In 10 (i)
			300,000	P.263.1 In 11 (i)
			566	P.263.1 In 17 (i)
			22,836	P.263.1 In 18 (i)
6	Real and Personal Property - Other Jurisdictions	35,666	453	P.263.1 In 14 (i)
			250	P.263.1 In 15 (i)
			(1,810)	P.263.1 In 20 (i)
			36,288	P.263.1 In 21 (i)
			485	P.263.1 In 24 (i)
7	<b>Payroll Taxes</b>			
8	Federal Insurance Contribution (FICA )	3,870,326	3,870,326	P.263 In 3 (i)
9	Federal Unemployment Tax	24,799	24,799	P.263 In 4 (i)
10	State Unemployment Insurance	51,461	51,461	P.263 In 18 (i)
11	Payroll Taxes	886,143	886,143	P.263 In 5 (i)
12	<b>Production Taxes</b>			
13	State Severance Taxes	-	-	
14	<b>Miscellaneous Taxes</b>			
15	State Business & Occupation Tax	-	-	
16	State Public Service Commission Fees	2,756,472	2,756,472	P.263 In 13 (i)
17	State Franchise Taxes	150,408	29,968	P.263 In 21 (i)
			1,690	P.263 In 34 (i)
			118,750	P.263 In 35 (i)
18	State Lic/Registration Fee	20,466	20,466	P.263.1 In 28 (i)
19	Misc. State and Local Tax	410	410	P.263.1 In 29 (i)
20	Sales & Use	7,118	520	P.263 In 15 (i)
			6,598	P.263 In 16 (i)
21	Federal Excise Tax	5,328	5,328	P.263 In 6 (i)
22	Michigan Single Business Tax	-	-	
23	Total Taxes by Allocable Basis (Total Company Amount Ties to FFI p.114, Ln 14,(c))	175,068,960	175,068,960	

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 2009 FF1 Balances**  
**Worksheet I Supporting Transmission Plant in Service Additions**  
**COLUMBUS SOUTHERN POWER COMPANY**

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

**I. Calculation of Composite Depreciation Rate**

1	Transmission Plant @ Beginning of Historic Period (2009) (P.206, In 58,(b)):	570,478,232
2	Transmission Plant @ End of Historic Period (2009) (P.207, In 58,(g)):	619,883,849
3		<u>1,190,362,081</u>
4	Average Balance of Transmission Investment	595,181,041
5	Annual Depreciation Expense, Historic TCOS, In 276	12,769,913
6	Composite Depreciation Rate	2.15%
7	Round to 2.15% to Reflect a Composite Life of 47 Years	2.15%

**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	\$ 32,966,175	2.15%	\$ 708,773	\$ 59,064	11	\$ 649,704
10	February	\$ 2,323,530	2.15%	\$ 49,956	\$ 4,163	10	\$ 41,630
11	March	\$ 10,727,910	2.15%	\$ 230,650	\$ 19,221	9	\$ 172,989
12	April	\$ 2,589,813	2.15%	\$ 55,681	\$ 4,640	8	\$ 37,120
13	May	\$ 7,725,967	2.15%	\$ 166,108	\$ 13,842	7	\$ 96,894
14	June	\$ 3,974,306	2.15%	\$ 85,448	\$ 7,121	6	\$ 42,726
15	July	\$ 4,197,873	2.15%	\$ 90,254	\$ 7,521	5	\$ 37,605
16	August	\$ 2,466,554	2.15%	\$ 53,031	\$ 4,419	4	\$ 17,676
17	September	\$ 2,486,800	2.15%	\$ 53,466	\$ 4,456	3	\$ 13,368
18	October	\$ 2,471,839	2.15%	\$ 53,145	\$ 4,429	2	\$ 8,858
19	November	\$ 2,455,105	2.15%	\$ 52,785	\$ 4,399	1	\$ 4,399
20	December	\$ 3,937,307	2.15%	\$ 84,652	\$ 7,054	0	\$ -
21	Investment	<u>\$ 78,323,180</u>				Depreciation Expense	<u>\$ 1,122,969</u>

**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 2010**

		<u>Estimated Cost</u>	
		<u>(000's)</u>	<u>Month in Service</u>
25	<b>Major Zonal Projects</b>		
26	000011820 TS CSP OH MARQUIS STATION 345	\$7,219	Jan-10
27	000013571 TS/CSP/Jug St Rd Station	\$8,160	Jan-10
28	000014471 TS/CSP/Lincoln - Berrywood	\$2,131	Jan-10
29	000013266 TS/CSP/new Roberts Station Cst	\$7,611	Jan-10
30	000016238 T/CSP/Security Application Enh	\$8,625	Multiple Months
31	000011617 TL/CSP/ROSS-HIGHLAND REBLD	\$5,404	Jan-10
32	000012095 TL/CSP/Line Pole Rehab/Repl	\$5,685	Multiple Months
33		<u>Subtotal</u>	
		44,835	
34	<b>PJM Socialized/Beneficiary Allocated Regional Projects</b>		
35	N/A	\$0	
36		<u>Subtotal</u>	
		\$0	

AEP East Companies  
 Cost of Service Formula Rate Using 2009 FF1 Balances  
 Worksheet J Supporting Calculation of PROJECTED PJM RTEP Project Revenue Requirement Billed to Benefiting Zones  
 COLUMBUS SOUTHERN POWER COMPANY

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

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

ROE w/o incentives (Projected TCOS, In 164)	11.49%	
Project ROE Incentive Adder		←ROE Adder Cannot Exceed 125 Basis Points
ROE with additional basis point incentive	11.49%	←ROE Including Incentives Cannot Exceed 12.74% Until July 1, 2012
Determine R (cost of long term debt, cost of preferred stock and equity percentage is from the Projected TCOS, Ins 162 through 164)		
	<u>%</u>	<u>Cost</u>
Long Term Debt	52.29%	5.77%
Preferred Stock	0.00%	0.00%
Common Stock	47.71%	11.49%
		<u>Weighted cost</u>
		3.019%
		<u>5.482%</u>
	R =	8.501%

SUMMARY OF PROJECTED ANNUAL RTEP REVENUE REQUIREMENTS			
	Rev Require	W Incentives	Incentive Amounts
PROJECTED YEAR	2010	-	\$ -

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

Rate Base (Projected TCOS, In 78)	402,392,268
R (from A. above)	8.501%
Return (Rate Base x R)	34,209,242

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

Return (from B. above)	34,209,242
Effective Tax Rate (Projected TCOS, In 126)	35.68%
Income Tax Calculation (Return x CIT)	12,205,616
ITC Adjustment	(371,358)
Income Taxes	11,834,257

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

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

Annual Revenue Requirement (Projected TCOS, In 1)	144,467,615
T.E.A. & Lease Payments (Projected TCOS, Lns 105 & 106)	51,308,780
Return (Projected TCOS, In 134)	34,209,242
Income Taxes (Projected TCOS, In 133)	11,834,257
Annual Revenue Requirement, Less TEA Charges, Return and Taxes	47,115,336

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

Annual Revenue Requirement, Less TEA Charges, Return and Taxes	47,115,336
Return (from I.B. above)	34,209,242
Income Taxes (from I.C. above)	11,834,257
Annual Revenue Requirement, with Basis Point ROE increase	93,158,835
Depreciation (Projected TCOS, In 111)	12,599,554
Annual Rev. Req, w/ Basis Point ROE increase, less Depreciation	80,559,281

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

Net Transmission Plant (Projected TCOS, In 48)	379,771,216
Annual Revenue Requirement, with Basis Point ROE increase	93,158,835
FCR with Basis Point increase in ROE	24.53%
Annual Rev. Req, w/ Basis Point ROE increase, less Dep.	80,559,281
FCR with Basis Point ROE increase, less Depreciation	21.21%
FCR less Depreciation (Projected TCOS, In 9)	17.88%
Incremental FCR with Basis Point ROE increase, less Depreciation	3.34%

**III. Calculation of Composite Depreciation Rate**

Transmission Plant @ Beginning of Historic Period (2009) (P.206, In 58,(b)):	570,478,232
Transmission Plant @ End of Historic Period (2009) (P.207, In 58,(g)):	619,883,849
Subtotal	1,190,362,081
Average Transmission Plant Balance for 2009	595,181,041
Annual Depreciation Rate (Projected TCOS, In 111)	12,769,913
Composite Depreciation Rate	2.15%
Depreciable Life for Composite Depreciation Rate	46.61
Round to nearest whole year	47

CSP 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. [redacted] (e.g. ER05-925-000)

Project Description: [redacted]

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

Details		Current Year	2010
Investment Year	2008	ROE increase accepted by FERC (Basis Points)	-
Service Year (yyyy)	2008	FCR w/o incentives, less depreciation	17.88%
Service Month (1-12)		FCR w/incentives approved for these facilities, less dep.	17.88%
Useful life	47	Annual Depreciation Expense	-
CIAC (Yes or No)	No		

**CUMULATIVE HISTORY OF PROJECTED ANNUAL REVENUE REQUIREMENT:**  
 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 **
2008	-	-	-	-	-	\$		
2009	-	-	-	-	-	\$		
2010	-	-	-	-	-	\$		
2011	-	-	-	-	-	\$		
2012	-	-	-	-	-	\$		
2013	-	-	-	-	-	\$		
2014	-	-	-	-	-	\$		
2015	-	-	-	-	-	\$		
2016	-	-	-	-	-	\$		
2017	-	-	-	-	-	\$		
2018	-	-	-	-	-	\$		
2019	-	-	-	-	-	\$		
2020	-	-	-	-	-	\$		
2021	-	-	-	-	-	\$		
2022	-	-	-	-	-	\$		
2023	-	-	-	-	-	\$		
2024	-	-	-	-	-	\$		
2025	-	-	-	-	-	\$		
2026	-	-	-	-	-	\$		
2027	-	-	-	-	-	\$		
2028	-	-	-	-	-	\$		
2029	-	-	-	-	-	\$		
2030	-	-	-	-	-	\$		
2031	-	-	-	-	-	\$		
2032	-	-	-	-	-	\$		
2033	-	-	-	-	-	\$		
2034	-	-	-	-	-	\$		
2035	-	-	-	-	-	\$		
2036	-	-	-	-	-	\$		
2037	-	-	-	-	-	\$		
2038	-	-	-	-	-	\$		
2039	-	-	-	-	-	\$		
2040	-	-	-	-	-	\$		
2041	-	-	-	-	-	\$		
2042	-	-	-	-	-	\$		
2043	-	-	-	-	-	\$		
2044	-	-	-	-	-	\$		
2045	-	-	-	-	-	\$		
2046	-	-	-	-	-	\$		
2047	-	-	-	-	-	\$		
2048	-	-	-	-	-	\$		
2049	-	-	-	-	-	\$		
2050	-	-	-	-	-	\$		
2051	-	-	-	-	-	\$		
2052	-	-	-	-	-	\$		
2053	-	-	-	-	-	\$		
2054	-	-	-	-	-	\$		
2055	-	-	-	-	-	\$		
2056	-	-	-	-	-	\$		
2057	-	-	-	-	-	\$		
2058	-	-	-	-	-	\$		
2059	-	-	-	-	-	\$		
2060	-	-	-	-	-	\$		
2061	-	-	-	-	-	\$		
2062	-	-	-	-	-	\$		
2063	-	-	-	-	-	\$		
2064	-	-	-	-	-	\$		
2065	-	-	-	-	-	\$		
2066	-	-	-	-	-	\$		
2067	-	-	-	-	-	\$		
Project Totals								

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

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

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

**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, In 164)				11.49%
Project ROE Incentive Adde				0
ROE with additional 0 basis point incentive				11.49%
Determine R (cost of long term debt, cost of preferred stock and equity percentage is from the True-Up TCOS, lns 162 through 164)				
	%	Cost	Weighted cost	
Long Term Debt	52.63%	5.78%	3.040%	
Preferred Stock	0.00%	0.00%	0.000%	
Common Stock	47.37%	11.49%	5.443%	
		R =	8.482%	

SUMMARY OF TRUED-UP ANNUAL REVENUE REQUIREMENTS FOR RTEPPROJECTS			
TRUE-UP YEAR	2009	Rev Require	Incentive Amounts
As Projected in Prior Year WS J			\$ -
Actual after True-up		\$ -	\$ -
True-up of ARR For 2009		-	-

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

Rate Base (True-Up TCOS, In 78)	327,034,216
R (from A. above)	8.482%
Return (Rate Base x R)	27,739,417

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

Return (from B. above)	27,739,417
Effective Tax Rate (True-Up TCOS, In 126)	35.50%
Income Tax Calculation (Return x CIT)	9,848,124
ITC Adjustment	(377,022)
Income Taxes	9,471,102

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

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

Annual Revenue Requirement (True-Up TCOS, In 1)	134,592,329
T.E.A. & Lease Payments (True-Up TCOS, Lns 105 & 106)	51,306,780
Return (True-Up TCOS, In 134)	27,739,417
Income Taxes (True-Up TCOS, In 133)	9,471,102
Annual Revenue Requirement, Less TEA	46,073,030

Charges, Return and Taxes

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

Annual Revenue Requirement, Less TEA Charges, Return and Taxes	46,073,030
Return (from I.B. above)	27,739,417
Income Taxes (from I.C. above)	9,471,102
Annual Revenue Requirement, with 0 Basis Point ROE increase	83,283,549
Depreciation (True-Up TCOS, In 111)	12,648,371
Annual Rev. Req. w/ 0 Basis Point ROE	70,635,178

increase, less Depreciation

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

Net Transmission Plant (True-Up TCOS, In 48)	361,314,447
Annual Revenue Requirement, with 0 Basis Point ROE increase	83,283,549
FCR with 0 Basis Point increase in ROE	23.05%
Annual Rev. Req. w / 0 Basis Point ROE increase, less Dep.	70,635,178
FCR with 0 Basis Point ROE increase, less Depreciation	19.55%
FCR less Depreciation (True-Up TCOS, In 9)	19.55%
Incremental FCR with 0 Basis Point ROE	0.00%

increase, less Depreciation

**III. Calculation of Composite Depreciation Rate**

Transmission Plant @ Beginning of Historic Period (P.206, In 58,(b)):	570,478,232
Transmission Plant @ End of Historic Period (P.207, In 58,(g)):	619,883,849
Subtotal	1,190,362,081
Average Transmission Plant Balance for	595,181,041
Annual Depreciation Rate (True-Up TCOS, In 111)	12,769,913
Composite Depreciation Rate	2.15%
Depreciable Life for Composite Depreciation Rate	46.61
Round to nearest whole year	47

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. [redacted] (e.g. ER05-925-000)

Project Description:

2009	Rev Require	W Incentives	Incentive Amounts
Prior Yr Projected	-	-	-
Prior Yr True-Up	-	-	-
True-Up Adjustment	-	-	-

Details		Current Year	2009
Investment			
Service Year (yyyy)	2008	ROE increase accepted by FERC (Basis Points)	-
Service Month (1-12)		FCR w/o incentives, less depreciation	19.55%
Useful life	47	FCR w/incentives approved for these facilities, less dep.	19.55%
CIAC (Yes or No)	No	Annual Depreciation Expense	-

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

Investment Year	Beginning Balance	Depreciation Expense	Ending Balance	Average Balance	RTEP Rev. Req't. w/o Incentives	RTEP Rev. Req't. with Incentives **	Incentive Rev. Requirement ##	RTEP Projected Rev. Req't. From Prior Year WS J w/o Incentives	RTEP Rev Req't True-up w/o Incentives	RTEP Projected Rev. Req't. From Prior Year WS J with Incentives **	RTEP Rev Req't True-up with Incentives **	True-up of Incentive with Incentives **
2008	-	-	-	-	-	-	-	-	-	-	-	-
2009	-	-	-	-	-	-	-	-	-	-	-	-
2010	-	-	-	-	-	-	-	-	-	-	-	-
2011	-	-	-	-	-	-	-	-	-	-	-	-
2012	-	-	-	-	-	-	-	-	-	-	-	-
2013	-	-	-	-	-	-	-	-	-	-	-	-
2014	-	-	-	-	-	-	-	-	-	-	-	-
2015	-	-	-	-	-	-	-	-	-	-	-	-
2016	-	-	-	-	-	-	-	-	-	-	-	-
2017	-	-	-	-	-	-	-	-	-	-	-	-
2018	-	-	-	-	-	-	-	-	-	-	-	-
2019	-	-	-	-	-	-	-	-	-	-	-	-
2020	-	-	-	-	-	-	-	-	-	-	-	-
2021	-	-	-	-	-	-	-	-	-	-	-	-
2022	-	-	-	-	-	-	-	-	-	-	-	-
2023	-	-	-	-	-	-	-	-	-	-	-	-
2024	-	-	-	-	-	-	-	-	-	-	-	-
2025	-	-	-	-	-	-	-	-	-	-	-	-
2026	-	-	-	-	-	-	-	-	-	-	-	-
2027	-	-	-	-	-	-	-	-	-	-	-	-
2028	-	-	-	-	-	-	-	-	-	-	-	-
2029	-	-	-	-	-	-	-	-	-	-	-	-
2030	-	-	-	-	-	-	-	-	-	-	-	-
2031	-	-	-	-	-	-	-	-	-	-	-	-
2032	-	-	-	-	-	-	-	-	-	-	-	-
2033	-	-	-	-	-	-	-	-	-	-	-	-
2034	-	-	-	-	-	-	-	-	-	-	-	-
2035	-	-	-	-	-	-	-	-	-	-	-	-
2036	-	-	-	-	-	-	-	-	-	-	-	-
2037	-	-	-	-	-	-	-	-	-	-	-	-
2038	-	-	-	-	-	-	-	-	-	-	-	-
2039	-	-	-	-	-	-	-	-	-	-	-	-
2040	-	-	-	-	-	-	-	-	-	-	-	-
2041	-	-	-	-	-	-	-	-	-	-	-	-
2042	-	-	-	-	-	-	-	-	-	-	-	-
2043	-	-	-	-	-	-	-	-	-	-	-	-
2044	-	-	-	-	-	-	-	-	-	-	-	-
2045	-	-	-	-	-	-	-	-	-	-	-	-
2046	-	-	-	-	-	-	-	-	-	-	-	-
2047	-	-	-	-	-	-	-	-	-	-	-	-
2048	-	-	-	-	-	-	-	-	-	-	-	-
2049	-	-	-	-	-	-	-	-	-	-	-	-
2050	-	-	-	-	-	-	-	-	-	-	-	-
2051	-	-	-	-	-	-	-	-	-	-	-	-
2052	-	-	-	-	-	-	-	-	-	-	-	-
2053	-	-	-	-	-	-	-	-	-	-	-	-
2054	-	-	-	-	-	-	-	-	-	-	-	-
2055	-	-	-	-	-	-	-	-	-	-	-	-
2056	-	-	-	-	-	-	-	-	-	-	-	-
2057	-	-	-	-	-	-	-	-	-	-	-	-
2058	-	-	-	-	-	-	-	-	-	-	-	-
2059	-	-	-	-	-	-	-	-	-	-	-	-
2060	-	-	-	-	-	-	-	-	-	-	-	-
2061	-	-	-	-	-	-	-	-	-	-	-	-
2062	-	-	-	-	-	-	-	-	-	-	-	-
2063	-	-	-	-	-	-	-	-	-	-	-	-
2064	-	-	-	-	-	-	-	-	-	-	-	-
2065	-	-	-	-	-	-	-	-	-	-	-	-
2066	-	-	-	-	-	-	-	-	-	-	-	-
2067	-	-	-	-	-	-	-	-	-	-	-	-
Project Totals	-	-	-	-	-	-	-	-	-	-	-	-

\*\* This is the total amount that needs to be reported to PJM for billing to all region

## 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 2009 FF1 Balances  
Worksheet L Supporting Projected Cost of Debt  
COLUMBUS SOUTHERN POWER COMPANY

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

<u>Line Number</u>	<u>(A) Issuance</u>	<u>(B) Principle Outstanding</u>	<u>(C) Interest Rate</u>	<u>(D) Annual Expense (See Note S on Projected Template)</u>	<u>(E) Notes</u>
1	<b>Long Term Debt (FF1.p. 256-257.h)</b>				
2	Notes Payable Affiliates	100,000,000	4.640%	4,640,000	
3					
4	<b>Installment Purchase Contracts (FF1.p. 256-257.h, a)</b>				
5	Ohio Rev Bonds Series 2007A	44,500,000	4.850%	2,158,250	
6	Ohio Rev Bonds Series 2007B	56,000,000	5.100%	2,856,000	
7	Ohio Rev Bonds Series 2009A	60,000,000	3.875%	2,325,000	
8	Ohio Rev Bonds Series 2009B	32,245,000	5.800%	1,870,210	
9				-	
10				-	
11				-	
12				-	
13				-	
14				-	
15	Unsecured Medium Series A - Due 2013	250,000,000	5.500%	13,750,000	
16	Unsecured Medium Series B - Due 2033	250,000,000	6.600%	16,500,000	
17	Unsecured Medium Series E - Due 2010	150,000,000	4.400%	6,600,000	
18	Unsecured Medium Series F - Due 2035	250,000,000	5.850%	14,625,000	
19	Unsecured Medium Series G - Due 2018	350,000,000	6.050%	21,175,000	
20				-	
21				-	
22				-	
23				-	
24				-	
25				-	
26	Sale/Leaseback				
27	<u>Issuance Discount, Premium, &amp; Expenses:</u>				
28	Auction Fees	FF1.p. 256 & 257.Lines Described as Fees		-	
29	Allowable Hedge Amortization (See Ln 45 Below)			-	
30	Amort of Debt Discount and Expenses	FF1.p. 117.63.c		1,841,488	
31	Amort of Debt Premimums (Enter Negative)	FF1.p. 117.65.c		-	
32	<u>Reacquired Debt:</u>				
33	Amortization of Loss	FF1.p. 117.64.c		743,496	
34	Amortization of Gain	FF1.p. 117.66.c		-	
35	<b>Total Interest on Long Term Debt</b>	1,542,745,000	5.77%	89,084,444	
36	<b>Preferred Stock (FF1.p. 250-251)</b>	<b>Preferred Shares Outstanding</b>			
37			0.00%	-	
38				-	
39				-	
40	<b>Dividends on Preferred Stock</b>	-		-	
41	Net Total Hedge Gains and Losses (WS M, Ln 35, (E))			-	
42	Total Projected Capital Structure Balance for 2010 (Projected TCOS, Ln 165)			2,950,508,883	
43	Financial Hedge Recovery Limit - Five Basis Points of Total Capital			0.0005	
44	Limit of Recoverable Amount			1,475,254	
45	<b>Recoverable Hedge Amortization (Lesser of Ln 41 or Ln 44)</b>			-	

AEP East Companies  
 Transmission Cost of Service Formula Rate  
 COLUMBUS SOUTHERN POWER COMPANY

**Worksheet M Supporting Calculation of Capital Structure and Weighted Average Cost of Capital Based on Average of Balances At 12/31/2008 & 12/31/2009**

(A)	(B)	(C)	(D)	(E)
Line		Balances @ 12/31/2009	Balances @ 12/31/2008	Average
<b>Development of Average Balance of Common Equity</b>				
1	Proprietary Capital (112.16.c&d)	1,359,835,152	1,249,439,875	1,304,637,514
2	Less Preferred Stock (Ln 55 Below)	0	-	-
3	Less Account 216.1 (112.12.c&d)	2,064,800	10,201,991	6,133,396
4	Less Account 219.1 (112.15.c&d)	(49,993,531)	(46,850,860)	(48,422,196)
5	<b>Average Balance of Common Equity</b>	<b>1,407,763,883</b>	<b>1,286,088,744</b>	<b>1,346,926,314</b>

**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)	-	92,245,000	46,122,500
8	LT Advances from Assoc. Companies (112.20.c&d)	100,000,000	100,000,000	100,000,000
9	Senior Unsecured Notes (112.21.c&d)	1,442,745,000	1,442,745,000	1,442,745,000
10	Less: Fair Value Hedges (See Note on Ln 12 below)	-	-	-
11	<b>Total Average Debt</b>	<b>1,542,745,000</b>	<b>1,450,500,000</b>	<b>1,496,622,500</b>

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 2009**

14	Interest on Long Term Debt (256-257.33.i)			83,846,255
15	Less: Total Hedge Gain/Expense Accumulated from p 256-257, col. (i) of FERC Form 1 included in Ln 14 and shown in Ln 34 below.			-
16	Plus: Allowed Hedge Recovery From Ln 39 below.			-
17	Amort of Debt Discount & Expense (117.63.c)			1,841,488
18	Amort of Loss on Reacquired Debt (117.64.c)			743,496
19	Less: Amort of Premium on Debt (117.65.c)			-
20	Less: Amort of Gain on Reacquired Debt (117.66.c)			-
21	<b>Total Interest Expense (Ln 14 + Ln 17 + Ln 18 - Ln 19 - Ln 20)</b>			<b>86,431,239</b>
22	<b>Average Cost of Debt for 2009 (Ln 21/Ln 11)</b>			<b>5.78%</b>

**CALCULATION OF RECOVERABLE HEDGE GAINS/LOSSES**

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

HEDGE AMOUNTS BY ISSUANCE (FROM p. 256-257 (i) of the FERC Form 1)	Total Hedge (Gain)/Loss for 2009	Less Excludable Amounts (See NOTE on Line 23)	Net Includable Hedge Amount	Amortization Period	
				Remaining Unamortized Balance	Beginning Ending
24 Senior Unsecured Notes	0	0	0		
25 Senior Unsecured Notes	0	0	0		
26 Senior Unsecured Notes	0	0	0		
27 Senior Unsecured Notes	0	0	0		
28 Senior Unsecured Notes	0	0	0		
29 Senior Unsecured Notes	0	0	0		
30 Senior Unsecured Notes	0	0	0		
31 Senior Unsecured Notes	0	0	0		
32 Senior Unsecured Notes	0	0	0		
33 Senior Unsecured Notes	0	0	0		
34 Total Hedge Amortization	-	-	-		
35 Hedge Gain or Loss Prior to Application of Recovery Limit (Sum of Lines 24 to 33)			-		
36 Total Average Capital Structure Balance for 2009 (True-UP TCOS, Ln 165)			2,843,548,814		
37 Financial Hedge Recovery Limit - Five Basis Points of Total Capital			0.0005		
38 Limit of Recoverable Amount			1,421,774		
39 Recoverable Hedge Amortization (Lesser of Ln 35 or Ln 38)			-		

**Development of Cost of Preferred Stock**

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

**AEP East Companies**  
**Cost of Service Formula Rate Using 2009 FF1 Balances**  
**Worksheet N - Gains (Losses) on Sales of Plant Held For Future Use**  
**COLUMBUS SOUTHERN POWER COMPANY**

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

Line	(A) Date	(B) Property Description	(C) Function (T) or (G) T = Transmission G = General	(D) Basis	(E) Proceeds	(F) (Gain) / Loss	(G) Functional Allocator	(H) Functionalized Proceeds (Gain) / Loss	(I) FERC Account
1						-	0.000%	-	
2						-	0.000%	-	
3						-	0.000%	-	
4					Net (Gain) or Loss for 2009	- =====		- =====	

AEP East Companies  
**Cost of Service Formula Rate Using 2009 FF1 Balances**

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

Total AEP East Operating Company PBOP Settlement Amount 48,100,000

**Allocation of PBOP Settlement Amount for 2009**

Line#	Company	Total Company Amount						
		Actual Expense (Including AEPSC Billed OPEB)	Ratio of Company Actual to Total	Allocation of PBOP Recovery Allowance	Labor Allocator for 2008	Actual Expense	Allowable Expense	One Year Functional Expense (Over)/Under
		(A)	(B)=(A)/Total (A)	(C)=(B) * 48100000	(D)	(E)=(A) * (D)	(F)=(C) * (D)	(G)=(E) - (F)
		(Line 14)						
1	APCo	18,441,517	29.26%	14,073,264	7.028%	1,296,063	989,064	306,999
2	CSP	10,281,860	16.31%	7,846,390	4.162%	427,913	326,553	101,360
3	I&M	12,473,804	19.79%	9,519,127	4.127%	514,802	392,861	121,941
4	KPCo	3,529,520	5.60%	2,693,481	8.595%	303,351	231,496	71,855
5	KNGP	544,295	0.86%	415,367	11.148%	60,678	46,305	14,373
6	OPCo	17,102,723	27.13%	13,051,591	7.326%	1,252,955	956,167	296,788
7	WPCo	656,219	1.04%	500,780	4.102%	26,916	20,540	6,376
8	Sum of Lines 1 to 7	63,029,939		48,100,000		3,882,678	2,962,986	919,692

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

	APCo	CSP	I&M	KPCo	KNGSPT	OPCo	WPCo	AEP East Total
9 Direct Charged PBOP Expense per Actuarial Report	25,117,708	11,854,216	19,543,777	4,099,566	620,366	20,108,946	765,967	82,110,546
10 Additional PBOP Ledger Entries (from Company Records)	(3,087,412)	24,390	(4,186,450)	(1)	-	(210,679)	-	
11 Medicare Subsidy	(5,206,873)	(2,393,921)	(4,008,620)	(867,380)	(123,297)	(4,175,705)	(152,317)	(16,928,113)
12 Net Company Expense (Ln 9 + Ln 10 + Ln 11)	16,823,423	9,484,685	11,348,707	3,232,185	497,069	15,722,562	613,650	57,722,281
13 PBOP Expenses From AEP Service Corporation (from Company Records)	1,618,094	797,175	1,125,097	297,335	47,226	1,380,161	42,569	5,307,658
14 Company PBOP Expense (Ln 12 + Ln 13)	18,441,517	10,281,860	12,473,804	3,529,520	544,295	17,102,723	656,219	63,029,939

**AEP EAST COMPANIES  
 PJM FORMULA RATE  
 WORKSHEET P - TRANSMISSION DEPRECIATION RATES  
 EFFECTIVE AS OF 1/1/2009  
 FOR SINGLE JURISDICTION COMPANIES  
 COLUMBUS SOUTHERN POWER COMPANY**

	<b>PLANT ACCT.</b>	<b>RATES Note 1</b>
<b><i>TRANSMISSION PLANT</i></b>		
Structures & Improvements	352.0	2.10%
- Zimmer Plant	352.0	2.50%
- CCD Struct & Improvements	352.0	2.50%
Station Equipment	353.0	2.16%
- Zimmer Plant	353.0	2.86%
- CCD Station Equipment	353.0	2.86%
Towers & Fixtures	354.0	2.44%
- CCD Towers	354.0	3.00%
Poles & Fixtures	355.0	2.44%
- CCD Poles	355.0	3.00%
Overhead Conductor	356.0	2.00%
- CCD OH Conductor	356.0	2.50%
Underground Conduit	357.0	2.27%
Underground Conductors	358.0	3.33%

Reference:

Note 1: PUCO Rates from Case No. 91-418-EL-AIR

Note 2: CCD (Columbus, Cincinnati, Dayton) represents property jointly owned by CSP, Dayton Power & Light, and Cinergy (now Duke Energy).

**General Note**

Per the terms of the settlement in this case, AEP will make a 205 filing whenever a company's rates are changed by their commission(s), or if the methodology to calculate the jurisdictional allocator in multiple-state companies changes. Changes in the allocation factors will not necessitate a 205 filing.