

AEP East Companies
 Transmission Cost of Service Formula Rate
 Utilizing Historic Cost Data for 2010 and Projected Net Plant at Year-End 2011

COLUMBUS SOUTHERN POWER COMPANY

Line No.			Total	Allocator	Transmission Amount
1	REVENUE REQUIREMENT (w/o incentives)	(In 138)			\$140,111,503
2	REVENUE CREDITS	(Note A) (Worksheet E)	9,333,424	DA 1.00000	\$ 9,333,424
3	REVENUE REQUIREMENT For All Company Facilities	(In 1 less In 2)			<u>\$ 130,778,079</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)				
6	Annual Rate	((In 1 - In 105 - In 106)/((In 48 + In 49 + In 50 + In 51 + In 53) x 100))			23.37%
7	Monthly Rate	(In 6 / 12)			1.95%
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 112)/((In 48 + In 49 + In 50 + In 51 + In 53) x 100))			20.05%
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 112- In 133 - In 134)/((In 48 + In 49 + In 50 + In 51 + In 53) x 100))			9.68%
12	ADDITIONAL REVENUE REQUIREMENT for projects w/ incentive ROE's (Note B) (Worksheet J)				-
13	REVENUE REQUIREMENT FOR SCHEDULE 1A CHARGES				
14	Total Load Dispatch & Scheduling (Account 561)	Line 85 Below			5,618,313
15	Less: Load Dispatch - Scheduling, System Control and Dispatch Services (321.88.b)				3,297,579
16	Less: Load Dispatch - Reliability, Planning & Standards Development Services (321.92.b)				803,012
17	Total 561 Internally Developed Costs	(Line 14 - Line 15 - Line 16)			<u>1,517,722</u>

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COLUMBUS SOUTHERN POWER COMPANY

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)	2,772,774,449	NA 0.00000	-
19	Less: Production ARO (Enter Negative)	(Worksheet A In 2.C)	(42,701,032)	NA 0.00000	-
20	Transmission	(Worksheet A In 3.C & Ln 142)	658,515,757	DA	644,834,842
21	Less: Transmission ARO (Enter Negative)	(Worksheet A In 4.C & Ln 143)	-	TP 0.97922	-
22	Plus: Transmission Plant-in-Service Additions (Worksheet I, In 21.D)		24,738,180	DA 1.00000	24,738,180
23	Plus: Additional Trans Plant on Transferred Assets (Worksheet I, In 22.D)		-	DA 1.00000	-
24	Distribution	(Worksheet A In 5.C)	1,792,666,828	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)	96,401,241	W/S 0.05961	5,746,126
27	Less: General Plant ARO (Enter Negative)	(Worksheet A In 8.C)	(144,371)	W/S 0.05961	(8,605)
28	Intangible Plant	(Worksheet A In 9.C)	60,243,856	W/S 0.05961	3,590,916
29	TOTAL GROSS PLANT	(sum Ins 18 to 28)	5,362,494,908		678,901,458
30	ACCUMULATED DEPRECIATION AND AMORTIZATION				
31	Production	(Worksheet A In 12.C)	1,061,823,494	NA 0.00000	-
32	Less: Production ARO (Enter Negative)	(Worksheet A In 13.C)	(13,189,171)	NA 0.00000	-
33	Transmission	(Worksheet A In 14.C & 28.C)	244,694,664	TP1= 0.97278	238,033,303
34	Less: Transmission ARO (Enter Negative)	(Worksheet A In 15.C)	-	TP1= 0.97278	-
35	Plus: Transmission Plant-in-Service Additions (Worksheet I, In 21.I)		269,072	DA 1.00000	269,072
36	Plus: Additional Projected Deprec on Transferred Assets (Worksheet I In 24.D)		-	DA 1.00000	-
37	Plus: Additional Transmission Depreciation for 2011 (In 111)		13,952,264	TP1 0.97278	13,572,439
38	Plus: Additional General & Intangible Depreciation for 2011 (In 113 + In 114)		13,097,445	W/S 0.05961	780,691
39	Plus: Additional Accum Deprec on Transferred Assets (Worksheet I In 23.D)		-	DA 1.00000	-
40	Distribution	(Worksheet A In 16.C)	747,603,548	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)	40,177,167	W/S 0.05961	2,394,814
43	Less: General Plant ARO (Enter Negative)	(Worksheet A In 19.C)	(82,310)	W/S 0.05961	(4,906)
44	Intangible Plant	(Worksheet A In 20.C)	52,419,579	W/S 0.05961	3,124,540
45	TOTAL ACCUMULATED DEPRECIATION	(sum Ins 31 to 44)	2,160,765,752		258,169,953
46	NET PLANT IN SERVICE				
47	Production	(In 18 + In 19 - In 31 - In 32)	1,681,439,094		-
48	Transmission	(In 20 + In 21 - In 33 - In 34)	413,821,093		406,801,539
49	Plus: Transmission Plant-in-Service Additions (In 22 - In 35)		24,469,108		24,469,108
50	Plus: Additional Trans Plant on Transferred Assets (In 23 - In 36)		-		-
51	Plus: Additional Transmission Depreciation for 2011 (-In 37)		(13,952,264)		(13,572,439)
52	Plus: Additional General & Intangible Depreciation for 2011 (-In 38)		(13,097,445)		(780,691)
53	Plus: Additional Accum Deprec on Transferred Assets (Worksheet I) (-In 39)		-		-
54	Distribution	(In 24 + In 25 - In 40 - In 41)	1,045,063,280		-
55	General Plant	(In 26 + In 27 - In 42 - In 43)	56,162,013		3,347,612
56	Intangible Plant	(In 28 - In 44)	7,824,277		466,377
57	TOTAL NET PLANT IN SERVICE	(sum Ins 47 to 56)	3,201,729,156		420,731,505
58	DEFERRED TAX ADJUSTMENTS TO RATE BASE	(Note D)			
59	Account No. 281.1 (enter negative)	(Worksheet B, In 2 & In 5.C)	(33,077,639)	NA	-
60	Account No. 282.1 (enter negative)	(Worksheet B, In 7 & In 10.C)	(619,603,952)	DA	(67,606,297)
61	Account No. 283.1 (enter negative)	(Worksheet B, In 12 & In 15.C)	(137,957,472)	DA	(7,503,382)
62	Account No. 190.1	(Worksheet B, In 17 & In 20.C)	111,780,327	DA	10,120,145
63	Account No. 255 (enter negative)	(Worksheet B, In 24 & In 25.C)	-	DA	-
64	TOTAL ADJUSTMENTS	(sum Ins 59 to 63)	(678,858,736)		(64,989,534)
65	PLANT HELD FOR FUTURE USE	(Worksheet A In 29.C & In 30.C)	13,026,227	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)	1,415,627		1,386,217
69	Transmission Materials & Supplies	(Worksheet C, In 2.(D))	178,726	TP 0.97922	175,013
70	A&G Materials & Supplies	(Worksheet C, In 3.(D))	34,360	W/S 0.05961	2,048
71	Stores Expense	(Worksheet C, In 4.(D))	-	GP(h) 0.12255	-
72	Prepayments (Account 165) - Labor Allocated	(Worksheet C, In 6.G)	127,936,031	W/S 0.05961	7,625,799
73	Prepayments (Account 165) - Gross Plant	(Worksheet C, In 6.F)	1,540,218	GP(h) 0.12255	188,760
74	Prepayments (Account 165) - Transmission Only	(Worksheet C, In 6.E)	-	DA 1.00000	-
75	Prepayments (Account 165) - Unallocable	(Worksheet C, In 6.D)	(111,681,980)	NA 0.00000	-
76	TOTAL WORKING CAPITAL	(sum Ins 68 to 75)	19,422,982		9,377,837
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)		2,555,319,629		368,916,497

AEP East Companies
Transmission Cost of Service Formula Rate
Utilizing Historic Cost Data for 2010 and Projected Net Plant at Year-End 2011

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
79	OPERATION & MAINTENANCE EXPENSE				
80	Production	321.80.b	1,104,158,339		
81	Distribution	322.156.b	82,865,557		
82	Customer Related Expense	322.164,171,178.b	92,717,281		
83	Regional Marketing Expenses	322.131.b	3,731,757		
84	Transmission	321.112.b	66,973,261		
85	TOTAL O&M EXPENSES	(sum Ins 79 to 83)	1,350,446,195		
86	Less: Total Account 561	(Note G) (Worksheet F, In 14.C)	5,618,313		
87	Less: Account 565	(Note H) 321.96.b	50,412,116		
88	Less: State Regulatory Deferrals & Amortizations	(Note I) (Worksheet F, In 4.C)	(382,185)		
88	Total O&M Allocable to Transmission	(Ins 83 - 85 - 86 - 87)	11,325,017	TP 0.97922	11,089,735
89	Administrative and General	323.197.b (Note J)	72,749,479		
90	Less: Acct. 924, Property Insurance	323.185.b	2,509,274		
91	Acct. 9260039 PBOP Expense	PBOP Worksheet O Line 9 & 10, (Note K)	9,778,864		
92	Acct. 9260057 PBOP Medicare Subsidy	PBOP Worksheet O Line 11, (Note K)	(2,596,761)		
93	PBOP Expense Billed From AEPSC	PBOP Worksheet O Line 13, (Note K)	577,531		
94	Acct. 928, Reg. Com. Exp.	323.189.b	292,655		
95	Acct. 930.1, Gen. Advert. Exp.	323.191.b	1,935,287		
96	Acct. 930.2, Misc. Gen. Exp.	323.192.b	1,356,406		
97	Balance of A & G	(In 89 - sum In 90 to In 96)	58,896,223	W/S 0.05961	3,510,589
98	Plus: Acct. 924, Property Insurance	(In 90)	2,509,274	GP(h) 0.12255	307,521
99	Acct. 928 - Transmission Specific	Worksheet F In 18.(E) (Note L)	-	TP 0.97922	-
100	Acct 930.1 - Only safety related ads -Direct	Worksheet F In 31.(E) (Note L)	-	TP 0.97922	-
101	Acct 930.2 - Misc Gen. Exp. - Trans	Worksheet F In 37.(E) (Note L)	194,135	DA 1.00000	194,135
102	Settlement Approved PBOP Recovery	PBOP Worksheet O, Col. C, Line 2, (Note M)	7,424,809	W/S 0.05961	442,566
103	A & G Subtotal	(sum Ins 97 to 102)	69,024,441		4,454,811
104	O & M EXPENSE SUBTOTAL	(In 88 + In 103)	80,349,458		15,544,546
105	Plus: TEA Settlement in Account 565	Company Records (Note H)	42,515,889	DA 1.00000	42,515,889
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)	122,865,347		58,060,435
108	DEPRECIATION AND AMORTIZATION EXPENSE				
109	Production	336.2-6.f	60,012,980	NA 0.00000	-
110	Distribution	336.8.f	61,613,392	NA 0.00000	-
111	Transmission	336.7.f	13,952,264	TP1 0.97278	13,572,439
112	Plus: Transmission Plant-in-Service Additions (Worksheet I In 21.1)		269,072	DA 1.00000	269,072
113	General	336.10.f	3,456,154	W/S 0.05961	206,009
114	Intangible	336.1.f	9,641,291	W/S 0.05961	574,682
115	TOTAL DEPRECIATION AND AMORTIZATION	(Lns 109+110+111 +112+113+114) (Note N)	148,945,153		14,622,202
116	TAXES OTHER THAN INCOME				
117	Labor Related				
118	Payroll	Worksheet H In 23.(D)	6,217,882	W/S 0.05961	370,625
119	Plant Related				
120	Property	Worksheet H In 23.(C) & In 37.(C)	101,818,306	DA	23,450,507
121	Gross Receipts/Sales & Use	Worksheet H In 23.(F)	76,769,171	NA 0.00000	-
122	Other	Worksheet H In 23.(E)	2,454,841	GP(h) 0.12255	300,851
123	TOTAL OTHER TAXES	(sum Ins 118 to 122)	187,260,200		24,121,983
124	INCOME TAXES	(Note O)			
125	$T=1 - \frac{((1 - SIT) * (1 - FIT))}{(1 - SIT * FIT * p)}$		35.61%		
126	$EIT=\frac{T}{(1-T)} * (1 - (WCLTD/WACC))$		38.21%		
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)		1.5530		
130	Amortized Investment Tax Credit (enter negative)	(FF1 p.114, In 19.c)	(2,045,599)		
131	Income Tax Calculation	(In 126 * In 134)	83,702,201		12,084,251
132	ITC adjustment	(In 129 * In 130)	(3,176,733)	NP(h) 0.12814	(407,082)
133	TOTAL INCOME TAXES	(sum Ins 131 to 132)	80,525,468		11,677,169
134	RETURN ON RATE BASE (Rate Base * WACC)	(In 78 * In 165)	219,084,882		31,629,713
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 (sum Ins 107, 115, 123, 133, 134, 135, 136, 137)		758,681,051		140,111,503

AEP East Companies
Transmission Cost of Service Formula Rate
Utilizing Historic Cost Data for 2010 and Projected Net Plant at Year-End 2011

COLUMBUS SOUTHERN POWER COMPANY

SUPPORTING CALCULATIONS

In							
No.	TRANSMISSION PLANT INCLUDED IN PJM TARIFF						
139	Total transmission plant	(In 20)					658,515,757
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)						13,680,915
142	Transmission plant included in PJM Tariff	(In 139 - In 140 - In 141)					<u>644,834,842</u>
143	Percent of transmission plant in PJM Tariff	(In 142 / In 139)				TP	0.97922
144	WAGES & SALARY ALLOCATOR (W/S)	(Note R)	Direct Payroll	Payroll Billed from AEP Service Corp.	Total		
145	Production	354.20.b	26,860,070	10,076,283	36,936,353	NA	0.00000
146	Transmission	354.21.b	3,227,657	2,618,842	5,846,499	TP	0.97922
147	Regional Market Expenses	354.22.b	0	0	-	NA	0.00000
148	Distribution	354.23.b	32,987,155	5,410,308	38,397,463	NA	0.00000
149	Other (Excludes A&G)	354.24,25,26.b	5,631,421	9,235,689	14,867,110	NA	0.00000
150	Total	(sum Ins 145 to 149)	<u>68,706,303</u>	<u>27,341,122</u>	<u>96,047,425</u>		<u>5,725,036</u>
151	Transmission related amount					W/S=	0.05961
152	WEIGHTED AVERAGE COST OF CAPITAL (WACC)						\$
153	Long Term Interest	(Worksheet L, In. 35, col. (D))					78,918,635
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)					1,486,215,163
157	Less: Preferred Stock	(FF1 p 112, Ln 3.c)					-
158	Less: Account 216.1	(FF1 p 112, Ln 12.c)					2,134,800
159	Less: Account 219	(FF1 p 112, Ln 15.c)					<u>(51,335,895)</u>
160	Common Stock	(In 156 - In 157 - In 158 - In 159)					<u>1,535,416,258</u>
161			\$	%		Cost (Note S)	Weighted
162	Long Term Debt (Note T) Worksheet L, In 35, col. (B))		<u>1,442,745,000</u>	48.44%		0.0547	0.0265
163	Preferred Stock (In 157)		-	0.00%		-	0.0000
164	Common Stock (In 160)		<u>1,535,416,258</u>	51.56%		11.49%	<u>0.0592</u>
165	Total (Sum Ins 162 to 164)		<u>2,978,161,258</u>			WACC=	0.0857

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 Transmission Cost of Service Formula Rate
 Utilizing Historic Cost Data for 2010 and Projected Net Plant at Year-End 2011

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 projected as of December 31, 2011. Other ratebase amounts are as of December 31, 2010.
- 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 = 0.93% (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
 Transmission Cost of Service Formula Rate
 Utilizing Historic Cost Data for 2010 with Year-End Rate Base Balances

COLUMBUS SOUTHERN POWER COMPANY

Line No.			Total	Allocator	Transmission Amount
166	REVENUE REQUIREMENT (w/o incentives)	(In 303)			\$138,643,760
167	REVENUE CREDITS	(Note A) (Worksheet E)	9,333,424	DA 1.00000	\$ 9,333,424
168	REVENUE REQUIREMENT For All Company Facilities	(In 166 less In 167)			\$ 129,310,336

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)			23.63%
172	Monthly Rate	(In 171 / 12)			1.97%
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)			20.29%
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)			9.94%
177	Not applicable on this template				

178 REVENUE REQUIREMENT FOR SCHEDULE 1A CHARGES					
179	Total Load Dispatch & Scheduling (Account 561)	Line 250 Below			5,618,313
180	Less: Load Dispatch - Scheduling, System Control and Dispatch Services (321.88.b)				3,297,579
181	Less: Load Dispatch - Reliability, Planning & Standards Development Services (321.92.b)				803,012
182	Total 561 Internally Developed Costs	(Line 179 - Line 180 - Line 181)			1,517,722

AEP East Companies
Transmission Cost of Service Formula Rate
Utilizing Historic Cost Data for 2010 with Year-End Rate Base Balances

COLUMBUS SOUTHERN POWER COMPANY

	(1)	(2)	(3)	(4)	(5)	
	Data Sources		TO Total	Allocator	Total	
	(See "General Notes")		NOTE C		Transmission	
Line No.	RATE BASE CALCULATION					
183	GROSS PLANT IN SERVICE					
183	Production	(Worksheet A In 1.C)	2,772,774,449	NA	0.00000	-
184	Less: Production ARO (Enter Negative)	(Worksheet A In 2.C)	(42,701,032)	NA	0.00000	-
185	Transmission	(Worksheet A In 3.C & Ln 307)	658,515,757	DA		644,834,842
186	Less: Transmission ARO (Enter Negative)	(Worksheet A In 4.C& Ln 308)	-	TP	0.97922	-
187	Plus: Transmission Plant-in-Service Additions (Worksheet I)		N/A	NA	0.00000	N/A
188	Plus: Additional Trans Plant on Transferred Assets (Worksheet I)		N/A	NA	0.00000	N/A
189	Distribution	(Worksheet A In 5.C)	1,792,666,828	NA	0.00000	-
190	Less: Distribution ARO (Enter Negative)	(Worksheet A In 6.C)	-	NA	0.00000	-
191	General Plant	(Worksheet A In 7.C)	96,401,241	W/S	0.05961	5,746,126
192	Less: General Plant ARO (Enter Negative)	(Worksheet A In 8.C)	(144,371)	W/S	0.05961	(8,605)
193	Intangible Plant	(Worksheet A In 9.C)	60,243,856	W/S	0.05961	3,590,916
194	TOTAL GROSS PLANT	(sum Ins 183 to 193)	5,337,756,728	GP(h)=	0.122554	654,163,279
				GTD=	0.26307	
195	ACCUMULATED DEPRECIATION AND AMORTIZATION					
196	Production	(Worksheet A In 12.C)	1,061,823,494	NA	0.00000	-
197	Less: Production ARO (Enter Negative)	(Worksheet A In 13.C)	(13,189,171)	NA	0.00000	-
198	Transmission	(Worksheet A In 14.C & 28.C)	244,694,664	TP1=	0.97278	238,033,303
199	Less: Transmission ARO (Enter Negative)	(Worksheet A In 15.C)	-	TP1=	0.97278	-
200	Plus: Transmission Plant-in-Service Additions (Worksheet I)		N/A	DA	1.00000	N/A
201	Plus: Additional Projected Deprec on Transferred Assets (Worksheet I)		N/A	DA	1.00000	N/A
202	Plus: Additional Transmission Depreciation for 2011 (In 276)		N/A	TP1	0.97278	N/A
203	Plus: Additional General & Intangible Depreciation for 2011 (In 275 + In 276)		N/A	W/S	0.05961	N/A
204	Plus: Additional Accum Deprec on Transferred Assets (Worksheet I)		N/A	DA	1.00000	N/A
205	Distribution	(Worksheet A In 16.C)	747,603,548	NA	0.00000	-
206	Less: Distribution ARO (Enter Negative)	(Worksheet A In 17.C)	-	NA	0.00000	-
207	General Plant	(Worksheet A In 18.C)	40,177,167	W/S	0.05961	2,394,814
208	Less: General Plant ARO (Enter Negative)	(Worksheet A In 19.C)	(82,310)	W/S	0.05961	(4,906)
209	Intangible Plant	(Worksheet A In 20.C)	52,419,579	W/S	0.05961	3,124,540
210	TOTAL ACCUMULATED DEPRECIATION	(sum Ins 196 to 209)	2,133,446,971			243,547,751
211	NET PLANT IN SERVICE					
212	Production	(In 183 + In 184 - In 196 - In 197)	1,681,439,094			-
213	Transmission	(In 185 + In 186 - In 198 - In 199)	413,821,093			406,801,539
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 2011 (-In 202)		N/A			N/A
217	Plus: Additional General & Intangible Depreciation for 2011 (-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)	1,045,063,280			-
220	General Plant	(In 191 + In 192 - In 207 - In 208)	56,162,013			3,347,612
221	Intangible Plant	(In 193 - In 209)	7,824,277			466,377
222	TOTAL NET PLANT IN SERVICE	(sum Ins 212 to 221)	3,204,309,757	NP(h)=	0.128145	410,615,528
223	DEFERRED TAX ADJUSTMENTS TO RATE BASE					
224	Account No. 281.1 (enter negative)	(Worksheet B, In 2 & In 5.C)	(33,077,639)	NA		-
225	Account No. 282.1 (enter negative)	(Worksheet B, In 7 & In 10.C)	(619,603,952)	DA		(67,606,297)
226	Account No. 283.1 (enter negative)	(Worksheet B, In 12 & In 15.C)	(137,957,472)	DA		(7,503,382)
227	Account No. 190.1	(Worksheet B, In 17 & In 20.C)	111,780,327	DA		10,120,145
228	Account No. 255 (enter negative)	(Worksheet B, In 24 & In 25.C)	-	DA		-
229	TOTAL ADJUSTMENTS	(sum Ins 224 to 228)	(678,858,736)			(64,989,534)
230	PLANT HELD FOR FUTURE USE	(Worksheet A In 29.C & In 30.C)	13,026,227	DA		3,796,688
231	REGULATORY ASSETS	(Worksheet A In 36. (C))	-	DA		-
232	WORKING CAPITAL					
233	Cash Working Capital	(Note E) (1/8 * In 253)	1,415,627			1,386,217
234	Transmission Materials & Supplies	(Worksheet C, In 2.(D))	178,726	TP	0.97922	175,013
235	A&G Materials & Supplies	(Worksheet C, In 3.(D))	34,360	W/S	0.05961	2,048
236	Stores Expense	(Worksheet C, In 4.(D))	-	GP(h)	0.12255	-
237	Prepayments (Account 165) - Labor Allocated	(Worksheet C, In 6.G)	127,936,031	W/S	0.05961	7,625,799
238	Prepayments (Account 165) - Gross Plant	(Worksheet C, In 6.F)	1,540,218	GP(h)	0.12255	188,760
239	Prepayments (Account 165) - Transmission Only	(Worksheet C, In 6.E)	-	DA	1.00000	-
240	Prepayments (Account 165) - Unallocable	(Worksheet C, In 6.D)	(111,681,980)	NA	0.00000	-
241	TOTAL WORKING CAPITAL	(sum Ins 233 to 240)	19,422,982			9,377,837
242	IPP CONTRIBUTIONS FOR CONSTRUCTION	(Note F) (Worksheet D, In 7.B)	-	DA	1.00000	-
243	RATE BASE (sum Ins 222, 229, 230, 231, 241, 242)		2,557,900,230			358,800,519

AEP East Companies
Transmission Cost of Service Formula Rate
Utilizing Historic Cost Data for 2010 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		
245	Distribution	322.156.b		
246	Customer Related Expense	322 & 323.164,171,178.b		
247	Regional Marketing Expenses	322.131.b		
248	Transmission	321.112.b		
249	TOTAL O&M EXPENSES	(sum Ins 244 to 248)		
250	Less: Total Account 561	(Note G) (Worksheet F, In 14.C)		
251	Less: Account 565	(Note H) 321.96.b		
252	Less: Regulatory Deferrals & Amortizations	(Note I) (Worksheet F, In 4.C)		
253	Total O&M Allocable to Transmission	(Ins 248 - 250 - 251 - 252)	TP	0.97922
254	Administrative and General	323.197.b (Note J)		
255	Less: Acct. 924, Property Insurance	323.185.b		
256	Acct. 9260039 PBOP Expense	PBOP Worksheet O Line 9 & 10, (Note K)		
257	Acct. 9260057 PBOP Medicare Subsidy	PBOP Worksheet O Line 11, (Note K)		
258	PBOP Expense Billed From AEPSC	PBOP Worksheet O Line 13, (Note K)		
259	Acct. 928, Reg. Com. Exp.	323.189.b		
260	Acct. 930.1, Gen. Advert. Exp.	323.191.b		
261	Acct. 930.2, Misc. Gen. Exp.	323.192.b		
262	Balance of A & G	(In 254 - sum In 255 to In 261)	W/S	0.05961
263	Plus: Acct. 924, Property Insurance	(In 255)	GP(h)	0.12255
264	Acct. 928 - Transmission Specific	Worksheet F In 18,(E) (Note L)	TP	0.97922
265	Acct 930.1 - Only safety related ads -Direct	Worksheet F In 31,(E) (Note L)	TP	0.97922
266	Acct 930.2 - Misc Gen. Exp. - Trans	Worksheet F In 37,(E) (Note L)	DA	1.00000
267	Settlement Approved PBOP Recovery	PBOP Worksheet O, Col. C, Line 2, (Note M)	W/S	0.05961
268	A & G Subtotal	(sum Ins 262 to 267)		
269	O & M EXPENSE SUBTOTAL	(In 253 + In 268)		
270	Plus: TEA Settlement in Account 565	Company Records (Note H)	DA	1.00000
271	Plus: Transmission Lease Payments To Affiliates in	Acct 565 (Company Records) (Note H)	DA	1.00000
272	TOTAL O & M EXPENSE	(In 269 + In 270 + In 271)		
273	DEPRECIATION AND AMORTIZATION EXPENSE			
274	Production	336.2-6.f	NA	0.00000
275	Distribution	336.8.f	NA	0.00000
276	Transmission	336.7.f	TP1	0.97278
277	Plus: Transmission Plant-in-Service Additions (Worksheet I)			
278	General	336.10.f	W/S	0.05961
279	Intangible	336.1.f	W/S	0.05961
280	TOTAL DEPRECIATION AND AMORTIZATION	(Ln 274+275+276+277+278+279)		
281	TAXES OTHER THAN INCOME	(Note N)		
282	Labor Related			
283	Payroll	Worksheet H In 23.(D)	W/S	0.05961
284	Plant Related			
285	Property	Worksheet H In 23.(C) & In 37.(C)	DA	23,450,507
286	Gross Receipts/Sales & Use	Worksheet H In 23.(F)	NA	0.00000
287	Other	Worksheet H In 23.(E)	GP(h)	0.12255
288	TOTAL OTHER TAXES	(sum Ins 283 to 287)		
289	INCOME TAXES	(Note O)		
290	$T=1 - ((1 - SIT) * (1 - FIT)) / (1 - SIT * FIT * p) =$	35.61%		
291	$EIT=(T/(1-T)) * (1-(WCLTD/WACC)) =$	38.21%		
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)	1.5530		
295	Amortized Investment Tax Credit (enter negative)	(FF1 p.114, In 19.c)		
296	Income Tax Calculation	(In 291 * In 299)		
297	ITC adjustment	(In 294 * In 295)	NP(h)	0.12814
298	TOTAL INCOME TAXES	(sum Ins 296 to 297)		
299	RETURN ON RATE BASE (Rate Base*WACC)	(In 243 * In 330)		
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	(sum Ins 272, 280, 288, 298, 299, 300, 301, 302)		

AEP East Companies
Transmission Cost of Service Formula Rate
Utilizing Historic Cost Data for 2010 with Year-End Rate Base Balances

COLUMBUS SOUTHERN POWER COMPANY

SUPPORTING CALCULATIONS

In										
<u>No.</u>	TRANSMISSION PLANT INCLUDED IN PJM TARIFF									
304	Total transmission plant	(In 185)								658,515,757
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)								13,680,915
307	Transmission plant included in PJM Tariff	(In 304 - In 305 - In 306)								644,834,842
308	Percent of transmission plant in PJM Tariff	(In 307 / In 304)							TP=	0.97922
309	WAGES & SALARY ALLOCATOR (W/S)	(Note R)	Direct Payroll	Payroll Billed from	Total					
310	Production	354.20.b	26,860,070	10,076,283	36,936,353	NA	0.00000			-
311	Transmission	354.21.b	3,227,657	2,618,842	5,846,499	TP	0.97922			5,725,036
312	Regional Market Expenses	354.22.b	0	0	-	NA	0.00000			-
313	Distribution	354.23.b	32,987,155	5,410,308	38,397,463	NA	0.00000			-
314	Other (Excludes A&G)	354.24,25,26.b	5,631,421	9,235,689	14,867,110	NA	0.00000			-
315	Total	(sum Ins 310 to 314)	68,706,303	27,341,122	96,047,425					5,725,036
316	Transmission related amount								W/S=	0.05961
317	WEIGHTED AVERAGE COST OF CAPITAL (WACC)									\$
318	Long Term Interest	(Worksheet L, In. 35, col. (D))								78,918,635
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)								1,486,215,163
322	Less: Preferred Stock	(FF1 p 112, Ln 3.c)								-
323	Less: Account 216.1	(FF1 p 112, Ln 12 .c)								2,134,800
324	Less: Account 219	(FF1 p 112, Ln 15.c)								(51,335,895)
325	Common Stock	(In 321 - In 322 - In 323 - In 324)								1,535,416,258
326			\$	%		Cost		Weighted		
327	Long Term Debt (Note T) Worksheet L, In 35, col. (B))		1,442,745,000	48.44%		0.0547		0.0265		
328	Preferred Stock (In 322)		-	0.00%		-		0.0000		
329	Common Stock (In 325)		1,535,416,258	51.56%		11.49%		0.0592		
330	Total (Sum Ins 327 to 329)		2,978,161,258					WACC=		0.0857

AEP East Companies
Transmission Cost of Service Formula Rate
Utilizing Historic Cost Data for 2010 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, 2010.
- 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 includes:
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= | 0.93% | (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 2010 with Average Ratebase Balances

COLUMBUS SOUTHERN POWER COMPANY

Line No.			Total	Allocator	Transmission Amount
1	REVENUE REQUIREMENT (w/o incentives)	(In 138)			\$137,470,247
2	REVENUE CREDITS	(Note A) (Worksheet E)	9,333,424	DA 1.00000	\$ 9,333,424
3	REVENUE REQUIREMENT For All Company Facilities	(In 1 less In 2)			<u>\$ 128,136,823</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 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)			24.14%
7	Monthly Rate	(In 6 / 12)			2.01%
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)			20.67%
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)			10.30%
12	ADDITIONAL REVENUE REQUIREMENT for projects w/ incentive ROE's (Note B) (Worksheet K)				-
13	REVENUE REQUIREMENT FOR SCHEDULE 1A CHARGES				
14	Total Load Dispatch & Scheduling (Account 561)	Line 85 Below			5,618,313
15	Less: Load Dispatch - Scheduling, System Control and Dispatch Services (321.88.b)				3,297,579
16	Less: Load Dispatch - Reliability, Planning & Standards Development Services (321.92.b)				803,012
17	Total 561 Internally Developed Costs	(Line 14 - Line 15 - Line 16)			<u>1,517,722</u>

AEP East Companies
Transmission Cost of Service Formula Rate
Utilizing Actual Cost Data for 2010 with Average Ratebase Balances

COLUMBUS SOUTHERN POWER COMPANY

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>
	GROSS PLANT IN SERVICE				
18	Production	(Worksheet A In 1.E)	2,747,910,653	NA	0.00000
19	Less: Production ARO (Enter Negative)	(Worksheet A In 2.E)	(37,754,069)	NA	0.00000
20	Transmission	(Worksheet A In 3.E & Ln 142)	639,199,803	DA	627,882,100
21	Less: Transmission ARO (Enter Negative)	(Worksheet A In 4.E & Ln 143)	-	TP	0.98229
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)	1,767,636,776	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)	96,131,672	W/S	0.05979
27	Less: General Plant ARO (Enter Negative)	(Worksheet A In 8.E)	(144,371)	W/S	0.05979
28	Intangible Plant	(Worksheet A In 9.E)	57,882,483	W/S	0.05979
29	TOTAL GROSS PLANT	(sum Ins 18 to 28)	5,270,862,946	GP(h)=	0.12087
				GTD=	0.00000
	ACCUMULATED DEPRECIATION AND AMORTIZATION				
30	Production	(Worksheet A In 12.E)	1,037,084,672	NA	0.00000
31	Less: Production ARO (Enter Negative)	(Worksheet A In 13.E)	(11,020,521)	NA	0.00000
32	Transmission	(Worksheet A In 14.E & 28.E)	239,489,148	TP1=	0.97957
33	Less: Transmission ARO (Enter Negative)	(Worksheet A In 15.E)	-	TP1=	0.97957
34	Plus: Transmission Plant-in-Service Additions (Worksheet I)		N/A	DA	1.00000
35	Plus: Additional Projected Deprec on Transferred Assets (Worksheet I)		N/A	DA	1.00000
36	Plus: Additional Transmission Depreciation for 2011 (In 111)		N/A	TP1	0.97957
37	Plus: Additional General & Intangible Depreciation for 2011 (In 110 + In 111)		N/A	W/S	0.05979
38	Plus: Additional Accum Deprec on Transferred Assets (Worksheet I)		N/A	DA	1.00000
39	Distribution	(Worksheet A In 16.E)	729,668,334	NA	0.00000
40	Less: Distribution ARO (Enter Negative)	(Worksheet A In 17.E)	-	NA	0.00000
41	General Plant	(Worksheet A In 18.E)	40,180,612	W/S	0.05979
42	Less: General Plant ARO (Enter Negative)	(Worksheet A In 19.E)	(80,500)	W/S	0.05979
43	Intangible Plant	(Worksheet A In 20.E)	49,595,876	W/S	0.05979
44	TOTAL ACCUMULATED DEPRECIATION	(sum Ins 31 to 44)	2,084,917,620		239,958,931
	NET PLANT IN SERVICE				
45	Production	(In 18 + In 19 - In 31 - In 32)	1,684,092,434		-
46	Transmission	(In 20 + In 21 - In 33 - In 34)	399,710,655		393,286,378
47	Plus: Transmission Plant-in-Service Additions (In 22 - In 35)		N/A		N/A
48	Plus: Additional Trans Plant on Transferred Assets (In 23 - In 36)		N/A		N/A
49	Plus: Additional Transmission Depreciation for 2011 (-In 37)		N/A		N/A
50	Plus: Additional General & Intangible Depreciation for 2011 (-In 38)		N/A		N/A
51	Plus: Additional Accum Deprec on Transferred Assets (Worksheet I) (-In 39)		N/A		N/A
52	Distribution	(In 24 + In 25 - In 40 - In 41)	1,037,968,442		-
53	General Plant	(In 26 + In 27 - In 42 - In 43)	55,887,189		3,341,673
54	Intangible Plant	(In 28 - In 44)	8,286,607		495,483
55	TOTAL NET PLANT IN SERVICE	(sum Ins 47 to 56)	3,185,945,326	NP(h)=	0.12465
	DEFERRED TAX ADJUSTMENTS TO RATE BASE				
56	Account No. 281.1 (enter negative)	(Worksheet B, In 2 & In 5.E)	(26,380,023)	NA	-
57	Account No. 282.1 (enter negative)	(Worksheet B, In 7 & In 10.E)	(574,993,359)	DA	(63,045,741)
58	Account No. 283.1 (enter negative)	(Worksheet B, In 12 & In 15.E)	(137,775,098)	DA	(7,693,791)
59	Account No. 190.1	(Worksheet B, In 17 & In 20.E)	100,202,580	DA	10,839,393
60	Account No. 255 (enter negative)	(Worksheet B, In 24 & In 25.E)	-	DA	-
61	TOTAL ADJUSTMENTS	(sum Ins 59 to 63)	(638,945,900)		(59,900,139)
62	PLANT HELD FOR FUTURE USE	(Worksheet A In 29.E & In 30.E)	12,824,123	DA	3,796,688
63	REGULATORY ASSETS	(Worksheet A In 36. (E))	-	DA	-
	WORKING CAPITAL				
64	Cash Working Capital	(Note E) (1/B - In 88)	1,415,627		1,390,562
65	Transmission Materials & Supplies	(Worksheet C, In 2.F)	245,027	TP	0.98229
66	A&G Materials & Supplies	(Worksheet C, In 3.F)	278,899	W/S	0.05979
67	Stores Expense	(Worksheet C, In 4.(D))	-	GP(h)	0.12087
68	Prepayments (Account 165) - Labor Allocated	(Worksheet C, In 8.G)	127,982,855	W/S	0.05979
69	Prepayments (Account 165) - Gross Plant	(Worksheet C, In 8.F)	1,537,220	GP(h)	0.12087
70	Prepayments (Account 165) - Transmission Only	(Worksheet C, In 8.E)	-	DA	1.00000
71	Prepayments (Account 165) - Unallocable	(Worksheet C, In 8.D)	(110,149,411)	NA	0.00000
72	TOTAL WORKING CAPITAL	(sum Ins 68 to 75)	21,310,217		9,486,230
73	IPP CONTRIBUTIONS FOR CONSTRUCTION	(Note F) (Worksheet D, In 8 (B))	-	DA	1.00000
74	RATE BASE (sum Ins 57, 64, 65, 66, 76, 77)		2,581,133,766		350,506,312

AEP East Companies
Transmission Cost of Service Formula Rate
Utilizing Actual Cost Data for 2010 with Average Ratebase Balances

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
	OPERATION & MAINTENANCE EXPENSE				
79	Production	321.80.b	1,104,158,339		
80	Distribution	322.156.b	82,865,557		
81	Customer Related Expense	322.164,171,178.b	92,717,281		
82	Regional Marketing Expenses	322.131.b	3,731,757		
83	Transmission	321.112.b	66,973,261		
84	TOTAL O&M EXPENSES	(sum Ins 79 to 83)	1,350,446,195		
85	Less: Total Account 561	(Note G) (Worksheet F, In 14.C)	5,618,313		
86	Less: Account 565	(Note H) 321.96.b	50,412,116		
87	Less: Regulatory Deferrals & Amortizations	(Note I) (Worksheet F, In 4.C)	(382,185)		
88	Total O&M Allocable to Transmission	(Ins 83 - 85 - 86 - 87)	11,325,017	TP 0.98229	11,124,496
89	Administrative and General	323.197.b (Note J)	72,749,479		
90	Less: Acct. 924, Property Insurance	323.185.b	2,509,274		
91	Acct. 9260039 PBOP Expense	PBOP Worksheet O Line 9 & 10, (Note K)	9,778,864		
92	Acct. 9260057 PBOP Medicare Subsidy	PBOP Worksheet O Line 11, (Note K)	(2,596,761)		
93	PBOP Expense Billed From AEPSC	PBOP Worksheet O Line 13, (Note K)	577,531		
94	Acct. 928, Reg. Com. Exp.	323.189.b	292,655		
95	Acct. 930.1, Gen. Advert. Exp.	323.191.b	1,935,287		
96	Acct. 930.2, Misc. Gen. Exp.	323.192.b	1,358,406		
97	Balance of A & G	(In 89 - sum In 90 to In 96)	58,896,223	W/S 0.05979	3,521,592
98	Plus: Acct. 924, Property Insurance	(In 90)	2,509,274	GP(h) 0.12087	303,293
99	Acct. 928 - Transmission Specific	Worksheet F In 18.(E) (Note L)	-	TP 0.97922	-
100	Acct 930.1 - Only safety related ads -Direct	Worksheet F In 31.(E) (Note L)	-	TP 0.97922	-
101	Acct 930.2 - Misc Gen. Exp. - Trans	Worksheet F In 37.(E) (Note L)	194,135	DA 1.00000	194,135
102	Settlement Approved PBOP Recovery	PBOP Worksheet O, Col. C, Line 2, (Note M)	7,424,809	W/S 0.05979	443,953
103	A & G Subtotal	(sum Ins 97 to 102)	69,024,441		4,462,973
104	O & M EXPENSE SUBTOTAL	(In 88 + In 103)	80,349,458		15,587,469
105	Plus: TEA Settlement in Account 565	Company Records (Note H)	42,515,889	DA 1.00000	42,515,889
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)	122,865,347		58,103,358
108	DEPRECIATION AND AMORTIZATION EXPENSE				
109	Production	336.2-6.f	60,012,980	NA 0.00000	-
110	Distribution	336.8.f	61,613,392	NA 0.00000	-
111	Transmission	336.7.f	13,952,264	TP1 0.97957	13,667,181
112	Plus: Transmission Plant-in-Service Additions (Worksheet I)		N/A		N/A
113	General	336.10.f	3,456,154	W/S 0.05979	206,654
114	Intangible	336.1.f	9,641,291	W/S 0.05979	576,483
115	TOTAL DEPRECIATION AND AMORTIZATION	(Ln 109+110+ 111+112+113+114) (Note N)	148,676,081		14,450,319
116	TAXES OTHER THAN INCOME				
117	Labor Related				
118	Payroll	Worksheet H In 23.(D)	6,217,882	W/S 0.05979	371,787
119	Plant Related				
120	Property	Worksheet H In 23.(C) & In 37.(C)	101,818,306	DA	23,450,507
121	Gross Receipts/Sales & Use	Worksheet H In 23.(F)	76,769,171	NA	0.00000
122	Other	Worksheet H In 23.(E)	2,454,841	GP(h) 0.12087	296,713
123	TOTAL OTHER TAXES	(sum Ins 118 to 122)	187,260,200		24,119,007
124	INCOME TAXES				
125	T=1 - (((1 - SIT) * (1 - FIT)) / (1 - SIT * FIT * p)) =	(Note O)	35.61%		
126	EIT=(T/(1-T)) * (1-(WCLTD/WACC)) =		36.68%		
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)		1.5530		
130	Amortized Investment Tax Credit (enter negative)	(FF1 p.114, In 19.c)	(2,045,599)		
131	Income Tax Calculation	(In 126 * In 134)	81,411,132		11,055,264
132	ITC adjustment	(In 129 * In 130)	(3,176,733)	NP(h) 0.12465	(395,975)
133	TOTAL INCOME TAXES	(sum Ins 131 to 132)	78,234,398		10,659,289
134	RETURN ON RATE BASE (Rate Base*WACC)	(In 78 * In 165)	221,938,708		30,138,274
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)		758,974,735		137,470,247

AEP East Companies
Transmission Cost of Service Formula Rate
Utilizing Actual Cost Data for 2010 with Average Ratebase Balances

COLUMBUS SOUTHERN POWER COMPANY

SUPPORTING CALCULATIONS

In No.	TRANSMISSION PLANT INCLUDED IN PJM TARIFF							
139	Total transmission plant	(In 20)						639,199,803
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)					11,317,703
142	Transmission plant included in PJM Tariff	(In 139 - In 140 - In 141)						627,882,100
143	Percent of transmission plant in PJM Tariff	(In 142 / In 139)					TP	0.98229
144	WAGES & SALARY ALLOCATOR (W/S)	(Note R)	Direct Payroll	Payroll Billed from AEP Service Corp.	Total			
145	Production	354.20.b	26,860,070	10,076,283	36,936,353	NA	0.00000	-
146	Transmission	354.21.b	3,227,657	2,618,842	5,846,499	TP	0.98229	5,742,981
147	Regional Market Expenses	354.22.b	0	0	-	NA	0.00000	-
148	Distribution	354.23.b	32,987,155	5,410,308	38,397,463	NA	0.00000	-
149	Other (Excludes A&G)	354.24,25,26.b	5,631,421	9,235,689	14,867,110	NA	0.00000	-
150	Total	(sum Ins 145 to 149)	68,706,303	27,341,122	96,047,425			5,742,981
151	Transmission related amount						W/S=	0.05979
152	WEIGHTED AVERAGE COST OF CAPITAL (WACC)							\$
153	Long Term Interest	(Worksheet M, In. 21, col. (E))						85,802,561
154	Preferred Dividends	(Worksheet M, In. 56, col. (E))						-
155	<u>Development of Common Stock:</u>							Average
156	Proprietary Capital	(Worksheet M, In. 1, col. (E))						1,423,025,158
157	Less: Preferred Stock	(Worksheet M, In. 2, col. (E))						-
158	Less: Account 216.1	(Worksheet M, In. 3, col. (E))						2,099,800
159	Less: Account 219	(Worksheet M, In. 4, col. (E))						(50,664,713)
160	Common Stock	(In 156 - In 157 - In 158 - In 159)						1,471,590,071
161		Average \$						
162	Long Term Debt (Note T) W/S M, In 11, In 22, col. (E))		1,492,745,000				0.0575	0.0289
163	Preferred Stock (In 157)		-	0.00%	0.00%		-	0.0000
164	Common Stock (In 160)		1,471,590,071	49.64%	0.00%		11.49%	0.0570
165	Total (Sum Ins 162 to 164)		2,964,335,071				WACC=	0.0860
166	Capital Structure Equity Limit (Note U)		51.0%					

AEP East Companies
 Transmission Cost of Service Formula Rate
 Utilizing Actual Cost Data for 2010 with Average Ratebase 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 reflect the average of the balances at December 31, 2009 and December 31, 2010.						
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. 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: 40px;"> <tr> <td>FIT =</td> <td>35.00%</td> </tr> <tr> <td>SIT =</td> <td>0.93% (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 =	0.93% (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 =	0.93% (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. Interest expense for the true-up WACC is based on actual expenses for the true-up year. The amount of eligible hedging gains or losses included in total interest expense is limited to five basis points of the true-up capital structure. Details and calculations of the true-up weighted average cost of capital are shown on Worksheet M. Eligible Hedging Gains and Losses are defined in the Formula Protocols in the tariff. and on Worksheet M.						
T	This note only applies to Indiana Michigan Power Company.						
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. During the period ended December 31, 2011 the equity cap is in effect. During this period, a change in the cap percentage must be approved via a 205 filing with the FERC.						

AEP East Companies
 Cost of Service Formula Rate Using 2010 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, 2010	Balance @ December 31, 2009	Average Balance for 2010
NOTE: Functional ARO investment and accumulated depreciation balances shown below are included in the total functional balances shown here					
Plant Investment Balances					
1	Production Plant In Service	FF1, page 205 Col.(g) & pg. 204 Col. (b), ln 46	2,772,774,449	2,723,046,857	2,747,910,653
2	Production Asset Retirement Obligation (ARO)	FF1, page 205&204, Col.(g)&(b), Ins 15,24,34,44	42,701,032	32,807,106	37,754,069
3	Transmission Plant In Service	FF1, page 207 Col.(g) & pg. 206 Col. (b), ln 58	658,515,757	619,883,849	639,199,803
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	1,792,666,828	1,742,606,724	1,767,636,776
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	96,401,241	95,862,102	96,131,672
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	60,243,856	55,521,109	57,882,483
10	Total Property Investment Balance	(Sum of Lines: 3, 1, 5, 7, 9)	5,380,602,131	5,236,920,641	5,308,761,386
11	Total ARO Balance (included in total on line 10)	(Sum of Lines: 4, 2, 6, 8)	42,845,403	32,951,477	37,898,440
Accumulated Depreciation & Amortization Balance:					
12	Production Accumulated Depreciator	FF1, page 219, Ins 20-24, Col. (b)	1,061,823,494	1,012,345,849	1,037,084,672
13	Production ARO Accumulated Depreciator	Company Records - Note 1	13,189,171	8,851,871	11,020,521
14	Transmission Accumulated Depreciator	FF1, page 219, ln 25, Col. (b)	244,694,664	234,283,632	239,489,148
15	Transmission ARO Accumulated Depreciator	Company Records - Note 1	-	-	-
16	Distribution Accumulated Depreciator	FF1, page 219, ln 26, Col. (b)	747,603,548	711,733,120	729,668,334
17	Distribution ARO Accumulated Depreciator	Company Records - Note 1	-	-	-
18	General Accumulated Depreciator	FF1, page 219, ln 28, Col. (b)	40,177,167	40,184,056	40,180,612
19	General ARO Accumulated Depreciator	Company Records - Note 1	82,310	78,690	80,500
20	Intangible Accumulated Amortization	FF1, page 200, ln 21, Col. (b)	52,419,579	46,772,172	49,595,876
21	Total Accumulated Depreciation or Amortization	(Sum of Lines: 14, 12, 16, 18, 20)	2,146,718,452	2,045,318,829	2,096,018,641
22	Total ARO Balance (included in total on line 21)	(Sum of Lines: 15, 13, 17, 19)	13,271,481	8,930,561	11,101,021
Generation Step-Up Units					
23	GSU Investment Amount	Company Records - Note 1	13,680,915	8,954,491	11,317,703
24	GSU Accumulated Depreciator	Company Records - Note 1	6,661,361	3,125,490	4,893,426
25	GSU Net Balance	(Line 23 - Line 24)	7,019,554	5,829,001	6,424,278
Transmission Accumulated Depreciation Net of GSU Accumulated Depreciation					
26	Transmission Accumulated Depreciator	(Line 14 Above)	244,694,664	234,283,632	239,489,148
27	Less: GSU Accumulated Depreciator	(Line 24 Above)	6,661,361	3,125,490	4,893,426
28	Subtotal of Transmission Net of GSU	(Line 26 - Line 27)	238,033,303	231,158,142	234,595,723
Plant Held For Future Use					
29	Plant Held For Future Use	FF1, page 214, ln 47, Col. (d)	13,026,227	12,622,018	12,824,123
30	Transmission Plant Held For Future Use	Company Records - Note 1	3,796,688	3,796,688	3,796,688
Regulatory Assets and Liabilities Approved for Recovery in Ratebase					
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 2010 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, 2010</u>	<u>(D) Balance @ December 31, 2009</u>	<u>(E) Average Balance for 2010</u>
1	<u>Account 281</u>				
2	Year End Utility Deferrals	FF1, p. 272 - 273, In 8, Col. (k)	33,077,639	19,682,408	26,380,023
3	Less: ARO Related Deferrals	Company Records - Note 1	-	-	-
4	Less: Other Excluded Deferrals	Company Records - Note 1	33,077,639	19,682,408	26,380,023
5	Transmission Related Deferrals	Ln 2 - In 3 - In 4	-	-	-
6	<u>Account 282</u>				
7	Year End Utility Deferrals	FF1, p. 274 - 275, In 5, Col. (k)	619,603,952	530,382,766	574,993,359
8	Less: ARO Related Deferrals	Company Records - Note 1	29,589,063	27,621,339	28,605,201
9	Less: Other Excluded Deferrals	Company Records - Note 1	522,408,592	444,276,243	483,342,418
10	Transmission Related Deferrals	Ln 7 - In 8 - In 9	67,606,297	58,485,184	63,045,741
11	<u>Account 283</u>				
12	Year End Utility Deferrals	FF1, p. 276 - 277, In 9, Col. (k)	137,957,472	137,592,723	137,775,098
13	Less: ARO Related Deferrals	Company Records - Note 1	-	-	-
14	Less: Other Excluded Deferrals	Company Records - Note 1	130,454,090	129,708,523	130,081,307
15	Transmission Related Deferrals	Ln 12 - In 13 - In 14	7,503,382	7,884,200	7,693,791
16	<u>Account 190</u>				
17	Year End Utility Deferrals	FF1, p. 234, In 8, Col. (c)	111,780,327	88,624,833	100,202,580
18	Less: ARO Related Deferrals	Company Records - Note 1	16,689,878	12,857,785	14,773,832
19	Less: Other Excluded Deferrals	Company Records - Note 1	84,970,304	64,208,408	74,589,356
20	Transmission Related Deferrals	Ln 17 - In 18 - In 19	10,120,145	11,558,640	10,839,393
21	<u>Account 255</u>				
22	Year End ITC Balances	FF1, p. 266-267, In 8, Col. (h)	14,787,360	16,832,959	15,810,160
23	Less: Balances Not Qualified for Ratebase	Company Records - Note 1	14,787,360	16,832,959	15,810,160
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 2010 FF1 Balances
Worksheet C Supporting Working Capital Rate Base Adjustments
COLUMBUS SOUTHERN POWER COMPANY

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
Materials & Supplies								
<u>Line Number</u>		<u>Source</u>	<u>Balance @ December 31, 2010</u>	<u>Balance @ December 31, 2009</u>	<u>Average Balance for 2010</u>			
1								
2	Transmission Materials & Supplies	FF1, p. 227, In 8, Col. (c) & (b)	178,726	311,327	245,027			
3	General Materials & Supplies	FF1, p. 227, In 11, Col. (c) & (b)	34,360	523,438	278,899			
4	Stores Expense (Undistributed)	FF1, p. 227, In 16, Col. (c) & (b)	0	0	-			

Prepayment Balance Summary

	<u>Average of YE Balance</u>	<u>Excludable Balances</u>	<u>100% Transmission Related</u>	<u>Transmission Plant Related</u>	<u>Transmission Labor Related</u>	<u>Total Included in Ratebase (E)+(F)+(G)</u>	
5							
6	Totals as of December 31, 2010	17,794,269	(111,681,980)	0	1,540,218	127,936,031	129,476,249
7	Totals as of December 31, 2009	20,947,059	(108,616,842)	-	1,534,222	128,029,679	129,563,901
8	Average Balance	19,370,664	(110,149,411)	-	1,537,220	127,982,855	129,520,075

Prepayments Account 165 - Balance @ 12/31/2010

9	<u>Acc. No.</u>	<u>Description</u>	<u>2010 YE Balance</u>	<u>Excludable Balances</u>	<u>100% Transmission Related</u>	<u>Transmission Plant Related</u>	<u>Transmission Labor Related</u>	<u>Total Included in Ratebase (E)+(F)+(G)</u>	<u>Explanation</u>
10	1650001	Prepaid Insurance	770,764	-	-	770,764	-	770,764	Plant Related Insurance Policies
11	165001210	Prepaid Sales/Use Taxes	60,000	-	-	60,000	-	60,000	Prepaid Taxes
12	1650003	Prepaid Rents	0	-	-	-	-	-	-
13	1650004	Prepaid Interest	0	-	-	-	-	-	-
14	1650005	Prepaid Employee Benefits	0	-	-	-	-	-	-
15	1650006	Other Prepayments	135,220	135,220	-	-	-	-	Relates to EPRI Dues
16	1650009	Prepaid Carry Cost-Factored AR	113,108	113,108	-	-	-	-	AR Factoring - Retail Only
17	1650010	Prepaid Pension Benefits	127,936,031	-	-	-	127,936,031	127,936,031	Prefunded Pension Expense
18	1650014	FAS 158 Qual Contra Asset	(127,936,031)	(127,936,031)	-	-	-	-	SFAS 158 Offset
19	1650016	FAS 112 ASSETS	0	-	-	-	-	-	-
20	1650017	Prepayment-Coal	6,594,000	6,594,000	-	-	-	-	Prepaid Coal
21	1650019	Prepaid Pension Expense - CG&E	5,724,326	5,724,326	-	-	-	-	-
22	1650020	Prepaid Pension Expense - DP&L	3,473,933	3,473,933	-	-	-	-	-
23	1650021	Prepaid Insurance - EIS	709,454	-	-	709,454	-	709,454	-
24	1650023	Prepaid Lease	7,908	-	-	-	-	-	-
25	1650024	LT Coal Prepayment	205,807	205,807	-	-	-	-	-
26	1650025	Reserve - LT Coal Prepayment	(251)	(251)	-	-	-	-	-
	Subtotal - Form 1, p 111.57.c		17,794,269	(111,681,980)	0	1,540,218	127,936,031	129,476,249	

Prepayments Account 165 - Balance @ 12/31/ 2009

27	<u>Acc. No.</u>	<u>Description</u>	<u>2009 YE Balance</u>	<u>Excludable Balances</u>	<u>100% Transmission Related</u>	<u>Transmission Plant Related</u>	<u>Transmission Labor Related</u>	<u>Total Included in Ratebase (E)+(F)+(G)</u>	<u>Explanation</u>
28	1650001	Prepaid Insurance	894,933	-	-	894,933	-	894,933	Plant Related Insurance Policies
29	165001209	Prepaid Sales/Use Taxes	65,000	-	-	65,000	-	65,000	Prepaid Taxes
30	1650003	Prepaid Rents	0	-	-	-	-	-	-
31	1650004	Prepaid Interest	0	-	-	-	-	-	Gen
32	1650005	Prepaid Employee Benefits	671,661	-	-	-	671,661	671,661	-
33	1650006	Other Prepayments	12,860	12,860	-	-	-	-	Relates to EPRI Dues
34	1650009	Prepaid Carry Cost-Factored AR	121,240	121,240	-	-	-	-	AR Factoring - Retail Only
35	1650010	Prepaid Pension Benefits	127,358,018	-	-	-	127,358,018	127,358,018	Prefunded Pension Expense
36	1650014	FAS 158 Qual Contra Asset	(127,358,018)	(127,358,018)	-	-	-	-	SFAS 158 Offset
37	1650016	FAS 112 ASSETS	552	-	-	-	-	-	SFAS 112 Overfunding Asset
38	1650017	Prepayment-Coal	2,090,319	2,090,319	-	-	-	-	Prepaid Coal
39	1650019	Prepaid Pension Expense - CG&E	2,618,528	2,618,528	-	-	-	-	-
40	1650020	Prepaid Pension Expense - DP&L	6,144,689	6,144,689	-	-	-	-	-
41	1650021	Prepaid Insurance - EIS	574,289	-	-	574,289	-	574,289	-
42	1650024	LT Coal Prepayment	7,763,619	7,763,619	-	-	-	-	-
43	1650025	Reserve - LT Coal Prepayment	(10,631)	(10,631)	-	-	-	-	-
	Subtotal - Form 1, p 111.57.d		20,947,059	(108,616,842)	-	1,534,222	128,029,679	129,563,901	

AEP East Companies
Cost of Service Formula Rate Using 2010 FF1 Balances
Worksheet D Supporting IPP Credits
COLUMBUS SOUTHERN POWER COMPANY

<u>Line Number</u>	<u>(A) Description</u>	<u>(B) 2010</u>
1	Net Funds from IPP Customers 12/31/2009 (2010 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 12/31/2010 (2010 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 2010 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)	2,665,604	2,665,604	-
2	Account 451, Miscellaneous Service Revenues (FF1 p.300.17.(b); Company Records - Note 1)	1,878,089	1,763,359	114,730
3	Account 454, Rent from Electric Property (FF1 p.300.19.(b); Company Records - Note 1)	20,077,352	11,864,791	8,212,561
4	Account 4560015, Associated Business Development- (Company Records - Note 1)	792,732	701,287	91,445
5	Account 456 - Other Electric Revenues - (Company Records - Note 1)	17,054,018	17,054,018	-
6	Subtotal - Other Operating Revenues (Company Total equals (FF1 p. 300.26.(b))	42,467,795	34,049,059	8,418,736
7	Accounts 4470004 & 5, Revenues from Grandfathered Transmission Contracts - (Company Records - Note 1)	943,758	29,070	914,688
8	Total Other Operating Revenues To Reduce Revenue Requirement	43,411,553	34,078,129	9,333,424

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 2010 FF1 Balances
 Worksheet F Supporting Allocation of Specific O&M or A&G Expenses
 COLUMBUS SOUTHERN POWER COMPANY

(A)	(B)	(C)	(D)	(E)	(F)	
<u>Line Number</u>	<u>Item No.</u>	<u>Description</u>	<u>2010 Expense</u>	<u>100% Non-Transmission</u>	<u>100% Transmission Specific</u>	<u>Explanation</u>
Regulatory O&M Deferrals & Amortizations						
1	5660005	Ohio E-TCR Rider Under Recovery	(382,185)			
2						
3						
4		Total	(382,185)			
Detail of Account 561 Per FERC Form 1						
5	FF1 p 321.84.b	561 - Load Dispatching	0			
6	FF1 p 321.85.b	561.1 - Load Dispatch - Reliability	21,190			
7	FF1 p 321.86.b	561.2 - Load Dispatch - Monitor & Operate Trans System	1,208,411			
8	FF1 p 321.87.b	561.3 - Load Dispatch - Trans Service & Scheduling	28			
9	FF1 p 321.88.b	561.4 - Scheduling, System Control & Dispatch	3,297,579			
10	FF1 p 321.89.b	561.5 - Reliability, Planning and Standards Development	288,093			
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	803,012			
14		Total of Account 561	5,618,313			
Account 928						
15	9280000	Regulatory Commission Exp	(22)	(22)		- Reg Comm Exp
16	9280001	Regulatory Commission Exp-Adm	171,920	171,920		- Reg Comm Exp-ADM
17	9280002	Regulatory Commission Exp-Case	120,757	120,757		- Reg Comm Exp-Case
18		Total	292,655	292,655		-
Account 930.1						
19	9301000	General Advertising Expenses	37,037	37,037		-
20	9301001	Newspaper Advertising Space	252,425	252,425		-
21	9301002	Radio Station Advertising Time	2,622	2,622		-
22	9301007	Special Adv Space & Prod Exp	1,393,784	1,393,784		-
23	9301008	Direct Mail and Handouts	-	-		-
24	9301009	Fairs, Shows, and Exhibits	163	163		-
25	9301010	Publicity	22,225	22,225		-
26	9301011	Dedications, Tours, & Openings	30	30		-
27	9301012	Public Opinion Surveys	126,295	126,295		-
28	9301013	Movies Slide Films & Speeches	-	-		-
29	9301014	Video Communications	85	85		-
30	9301015	Other Corporate Comm Exp	100,621	100,621		-
31		Total	1,935,287	1,935,287		-
Account 930.2						
32	9302000	Misc General Expenses	1,030,618	1,030,618		
33	9302003	Corporate & Fiscal Expenses	60,077	60,077		
34	9302004	Research, Develop&Demonstr Exp	41,162	41,162		
35	9302007	Assoc Business Development Exp	561,983	367,848	194,135	
36	9302019	gridSMART Rider Over/Under Recovery	-337,435	-337,435		
37		Total	1,356,405	1,162,270	194,135	

AEP East Companies
Cost of Service Formula Rate Using 2010 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 Note 1	0.00%	
Apportionment Factor - Note 2	0.00%	
Effective Ohio State Tax Rate		0.0000%
Ohio Municipal Income Tax Rate	0.92%	
Apportionment Factor - Note 2	94.59%	
Effective Indiana State Tax Rate		0.8702%
West Virginia Corporate Income Tax Rate	8.50%	
Apportionment Factor - Note 2	0.00%	
Effective West Virginia State Tax Rate		0.0000%
Michigan Business Income Tax Rate	6.04%	
Apportionment Factor - Note 2	0.50%	
Effective State Tax Rate		0.0302%
Kentucky Corporation Income Tax Rate	6.00%	
Apportionment Factor - Note 2	0.22%	
Effective State Tax Rate		0.0132%
Illinois Corporate Income Tax Rate	7.30%	
Apportionment Factor - Note 2	0.34%	
Effective State Tax Rate		0.0200%
Total Effective State Income Tax Rate		<u>0.9336%</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 2010 FF1 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
NOTE 1						
1	Revenue Taxes					
2	Gross Receipts Tax	5,556,658				5,556,658
3	KWH State Excise Tax	71,692,506				71,692,506
4	Real Estate and Personal Property Taxes					
5	Real and Personal Property - Ohio	101,781,272	101,781,272			
6	Real and Personal Property - Other Jurisdictions	37,034	37,034			
7	Payroll Taxes					
8	Federal Insurance Contribution (FICA)	5,101,991		5,101,991		
9	Federal Unemployment Tax	54,476		54,476		
10	State Unemployment Insurance	87,932		87,932		
11	Payroll Taxes	973,483		973,483		
12	Production Taxes					
13	State Severance Taxes	-				-
14	Miscellaneous Taxes					
15	State Business & Occupation Tax	-				-
16	State Public Service Commission Fees	2,672,152			2,672,152	
17	State Franchise Taxes	(217,336)			(217,336)	
18	State Lic/Registration Fee	25			25	
19	Misc. State and Local Tax	-			-	
20	Sales & Use	(482,616)				(482,616)
21	Federal Excise Tax	2,623				2,623
22	Michigan Single Business Tax	-				-
23	Total Taxes by Allocable Basis	<u>187,260,200</u>	<u>101,818,306</u>	<u>6,217,882</u>	<u>2,454,841</u>	<u>76,769,171</u>

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

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

Functional Property Tax Allocation

	Production	Transmission	Distribution	General	Total	
24	Functionalized Net Plant (Hist. TCOS, Lns 212 thru 222)	1,681,439,094	413,821,093	1,045,063,280	56,162,013	3,196,485,480
OHIO JURISDICTION						
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)	1,681,439,094	413,821,093	1,045,063,280	56,162,013	3,196,485,480
27	Less: Net Value of Exempted Generation Plant	485,879,171				
28	Taxable Property Basis (Ln 26 - Ln 27)	1,195,559,923	413,821,093	1,045,063,280	56,162,013	2,710,606,309
29	Relative Valuation Factor	24%	85%	85%	24%	
30	Weighted Net Plant (Ln 28 * Ln 29)	286,934,382	351,747,929	888,303,788	13,478,883	
31	General Plant Allocator (Ln 30 / (Total - General Plant))	18.79%	23.04%	58.17%	-100.00%	
32	Functionalized General Plant (Ln 31 * General Plant)	2,532,803	3,104,920	7,841,160	(13,478,883)	-
33	Weighted OHIO JURISDICTION Plant (Ln 30 + 32)	289,467,185	354,852,849	896,144,948	0	1,540,464,982
34	Functional Percentage (Ln 33/Total Ln 33)	18.79%	23.04%	58.17%		
35	Functionalized Expense in OHIO JURISDICTION	<u>19,125,614</u>	<u>23,445,761</u>	<u>59,209,897</u>		<u>101,781,272</u>
36	Total Other Jurisdictions: (Line 6 * Net Plant Allocator)		4,746			<u>37,034</u>
37	Total Func. Property Taxes (Sum Lns 35, 36)	<u>19,125,614</u>	<u>23,450,507</u>	<u>59,209,897</u>		<u>101,818,306</u>

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) Annual Tax Expenses by Type (Note 1)	(B) Total Company	(C) FERC FORM 1 Tie-Back	(D) FERC FORM 1 Reference
1	Revenue Taxes			
2	Gross Receipts Tax	5,556,658	(149,337) 5,705,995	P.263 ln 13 (i) P.263 ln 14 (i)
3	KWH State Excise Tax	71,692,506	71,692,506	P.263 ln 11 (i)
4	Real Estate and Personal Property Taxes			
5	Real and Personal Property - Ohio	101,781,272	(138,684) 101,743,129 (85,280) 263,120 (11,711) 10,698 - - - -	P.263 ln 40 (i) P.263.1 ln 1 (i) P.263.1 ln 4 (i) P.263.1 ln 6 (i) P.263.1 ln 11 (i) P.263.1 ln 12 (i)
6	Real and Personal Property - Other Jurisdictions	37,034	129 250 170 36,000 485	P.263.1 ln 8 (i) P.263.1 ln 9 (i) P.263.1 ln 14 (i) P.263.1 ln 15 (i) P.263.1 ln 18 (i)
7	Payroll Taxes			
8	Federal Insurance Contribution (FICA)	5,101,991	5,101,991	P.263 ln 3 (i)
9	Federal Unemployment Tax	54,476	54,476	P.263 ln 4 (i)
10	State Unemployment Insurance	87,932	87,932	P.263 ln 18 (i)
11	Payroll Taxes	973,483	973,483	P.263 ln 5 (i)
12	Production Taxes			
13	State Severance Taxes	-	-	
14	Miscellaneous Taxes			
15	State Business & Occupation Tax	-	-	
16	State Public Service Commission Fees	2,672,152	2,672,152	P.263 ln 12 (i)
17	State Franchise Taxes	(217,336)	(217,936) 600 -	P.263 ln 33 (i) P.263.1 ln 24 (i)
18	State Lic/Registration Fee	25	25	P.263.1 ln 23 (i)
19	Misc. State and Local Tax	-	-	
20	Sales & Use	(482,616)	207 3,785 (486,608)	P.263 ln 15 (i) P.263 ln 16 (i) P.263 ln 17 (i)
21	Federal Excise Tax	2,623	2,623	P.263 ln 6 (i)
22	Michigan Single Business Tax	-	-	
23	Total Taxes by Allocable Basis (Total Company Amount Ties to FFI p.114, Ln 14,(c))	187,260,200	187,260,200	

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 2010 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 (2010) (P.206, In 58,(b)):	619,883,849
2	Transmission Plant @ End of Historic Period (2010) (P.207, In 58,(g)):	658,515,757
3		1,278,399,606
4	Average Balance of Transmission Investment	639,199,803
5	Annual Depreciation Expense, Historic TCOS, In 276	13,952,264
6	Composite Depreciation Rate	2.18%
7	Round to 2.18% to Reflect a Composite Life of 46 Years	2.18%

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	\$ 2,334,447	2.18%	\$ 50,891	\$ 4,241	11	\$ 46,651
10	February	\$ 2,339,779	2.18%	\$ 51,007	\$ 4,251	10	\$ 42,510
11	March	\$ 2,696,912	2.18%	\$ 58,793	\$ 4,899	9	\$ 44,091
12	April	\$ 2,384,186	2.18%	\$ 51,975	\$ 4,331	8	\$ 34,648
13	May	\$ 2,472,056	2.18%	\$ 53,891	\$ 4,491	7	\$ 31,437
14	June	\$ 2,679,293	2.18%	\$ 58,409	\$ 4,867	6	\$ 29,202
15	July	\$ 2,333,280	2.18%	\$ 50,866	\$ 4,239	5	\$ 21,195
16	August	\$ 913,651	2.18%	\$ 19,918	\$ 1,660	4	\$ 6,640
17	September	\$ 1,279,747	2.18%	\$ 27,898	\$ 2,325	3	\$ 6,975
18	October	\$ 1,061,150	2.18%	\$ 23,133	\$ 1,928	2	\$ 3,856
19	November	\$ 1,027,856	2.18%	\$ 22,407	\$ 1,867	1	\$ 1,867
20	December	\$ 3,215,822	2.18%	\$ 70,105	\$ 5,842	0	\$ -
21	Investment	\$ 24,738,180				Depreciation Expense	\$ 269,072

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 Major Zonal Projects		
26 000011617 TL/CSP/ROSS-HIGHLAND REBLD	\$1,397	Multiple Months
27		
28		
29		
30		
31		
32		
33	Subtotal	1,397
34 PJM Socialized/Beneficiary Allocated Regional Projects		
35 N/A	\$0	
36	Subtotal	\$0

AEP East Companies
 Cost of Service Formula Rate Using 2010 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)			
	%	Cost	Weighted cost
Long Term Debt	48.44%	5.47%	2.650%
Preferred Stock	0.00%	0.00%	0.000%
Common Stock	51.56%	11.49%	5.924%
		R =	8.574%

SUMMARY OF PROJECTED ANNUAL RTEP REVENUE REQUIREMENTS			
	Rev Require	W Incentives	Incentive Amounts
PROJECTED YEAR	2011	-	\$ -

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

Rate Base (Projected TCOS, In 78)	368,916,497
R (from A. above)	8.574%
Return (Rate Base x R)	31,629,713

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

Return (from B. above)	31,629,713
Effective Tax Rate (Projected TCOS, In 126)	38.21%
Income Tax Calculation (Return x CIT)	12,084,251
ITC Adjustment	(407,082)
Income Taxes	11,677,169

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)	140,111,503
T.E.A. & Lease Payments (Projected TCOS, Lns 105 & 106)	42,515,889
Return (Projected TCOS, In 134)	31,629,713
Income Taxes (Projected TCOS, In 133)	11,677,169
Annual Revenue Requirement, Less TEA Charges, Return and Taxes	54,288,731

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

Annual Revenue Requirement, Less TEA Charges, Return and Taxes	54,288,731
Return (from I.B. above)	31,629,713
Income Taxes (from I.C. above)	11,677,169
Annual Revenue Requirement, with Basis Point ROE increase	97,595,614
Depreciation (Projected TCOS, In 111)	13,572,439
Annual Rev. Req, w/ Basis Point ROE increase, less Depreciation	84,023,174

C. Determine FCR with hypothetical basis point ROE increase.

Net Transmission Plant (Projected TCOS, In 48)	406,801,539
Annual Revenue Requirement, with Basis Point ROE increase	97,595,614
FCR with Basis Point increase in ROE	23.99%
Annual Rev. Req, w/ Basis Point ROE increase, less Dep.	84,023,174
FCR with Basis Point ROE increase, less Depreciation	20.05%
FCR less Depreciation (Projected TCOS, In 9)	20.05%
Incremental FCR with Basis Point ROE increase, less Depreciation	0.60%

III. Calculation of Composite Depreciation Rate

Transmission Plant @ Beginning of Historic Period (2010) (P.206, In 58,(b)):	619,883,849
Transmission Plant @ End of Historic Period (2010) (P.207, In 58,(g)):	659,615,757
Subtotal	1,278,399,606
Average Transmission Plant Balance for 2010	639,199,803
Annual Depreciation Rate (Projected TCOS, In 111)	13,952,264
Composite Depreciation Rate	2.18%
Depreciable Life for Composite Depreciation Rate	45.81
Round to nearest whole year	46

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	2011
Investment Year	2008	ROE increase accepted by FERC (Basis Points)	-
Service Year (yyyy)	2008	FCR w/o incentives, less depreciation	20.05%
Service Month (1-12)		FCR w/incentives approved for these facilities, less dep.	20.05%
Useful life	46	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 through164)				
	%	Cost	Weighted cost	
Long Term Debt	50.36%	5.75%	2.894%	
Preferred Stock	0.00%	0.00%	0.000%	
Common Stock	49.64%	11.49%	5.704%	
		R =	8.598%	

SUMMARY OF TRUED-UP ANNUAL REVENUE REQUIREMENTS FOR RTEPPROJECTS			
TRUE-UP YEAR	2010	Rev Require	Incentive Amounts
As Projected in Prior Year WS J			\$ -
Actual after True-up		\$ -	\$ -
True-up of ARR For 2010		-	-

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

Rate Base (True-Up TCOS, In 78)	350,506,312
R (from A. above)	8.598%
Return (Rate Base x R)	30,138,274

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

Return (from B. above)	30,138,274
Effective Tax Rate (True-Up TCOS, In 126)	36.68%
Income Tax Calculation (Return x CIT)	11,055,264
ITC Adjustment	(395,975)
Income Taxes	10,659,289

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)	137,470,247
T.E.A. & Lease Payments (True-Up TCOS, lns 105 & 106)	42,515,889
Return (True-Up TCOS, In 134)	30,138,274
Income Taxes (True-Up TCOS, In 133)	10,659,289
Annual Revenue Requirement, Less TEA	54,156,795

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	54,156,795
Return (from I.B. above)	30,138,274
Income Taxes (from I.C. above)	10,659,289
Annual Revenue Requirement, with 0 Basis Point ROE increase	94,954,358
Depreciation (True-Up TCOS, In 111)	13,667,181
Annual Rev. Req, w/ 0 Basis Point ROE	81,287,178

increase, less Depreciation

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

Net Transmission Plant (True-Up TCOS, In 48)	393,286,378
Annual Revenue Requirement, with 0 Basis Point ROE increase	94,954,358
FCR with 0 Basis Point increase in ROE	24.14%

Annual Rev. Req, w / 0 Basis Point ROE increase, less Dep.	81,287,178
FCR with 0 Basis Point ROE increase, less Depreciation	20.67%
FCR less Depreciation (True-Up TCOS, In 9)	20.67%
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)):	619,883,849
Transmission Plant @ End of Historic Period () (P.207, In 58,(g)):	598,515,757
Subtotal	1,278,399,606
Average Transmission Plant Balance for	639,199,803
Annual Depreciation Rate (True-Up TCOS, In 111)	13,952,264
Composite Depreciation Rate	2.18%
Depreciable Life for Composite Depreciation Rate	45.81
Round to nearest whole year	46

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:

2010	Rev Require	W Incentives	Incentive Amounts
Prior Yr Projected	-	-	-
Prior Yr True-Up	-	-	-
True-Up Adjustment	-	-	-

Details		Current Year	2010
Investment			
Service Year (yyyy)	2008	ROE increase accepted by FERC (Basis Points)	-
Service Month (1-12)		FCR w/o incentives, less depreciation	20.67%
Useful life	46	FCR w/incentives approved for these facilities, less dep.	20.67%
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 2010 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	Long Term Debt (FF1.p. 256-257.h)				
2				-	
3					
4	Installment Purchase Contracts (FF1.p. 256-257.h, a)				
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	Floating Rate Unsecured Note Series A	150,000,000	0.702%	1,053,000	
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 F - Due 2035	250,000,000	5.850%	14,625,000	
18	Unsecured Medium Series G - Due 2018	350,000,000	6.050%	21,175,000	
19				-	
20				-	
21				-	
22				-	
23				-	
24				-	
25				-	
26	Sale/Leaseback				
27	<u>Issuance Discount, Premium, & 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		1,862,634	
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		743,541	
34	Amortization of Gain	FF1.p. 117.66.c		-	
35	Total Interest on Long Term Debt	1,442,745,000	5.47%	78,918,635	
36	Preferred Stock (FF1.p. 250-251)	Preferred Shares Outstanding			
37			0.00%	-	
38				-	
39				-	
40	Dividends on Preferred Stock	-		-	
41	Net Total Hedge Gains and Losses (WS M, Ln 35, (E))			-	
42	Total Projected Capital Structure Balance for 2011 (Projected TCOS, Ln 165)			2,978,161,258	
43	Financial Hedge Recovery Limit - Five Basis Points of Total Capital			0.0005	
44	Limit of Recoverable Amount			1,489,081	
45	Recoverable Hedge Amortization (Lesser of Ln 41 or Ln 44)			-	

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 12/31/2009 & 12/31/2010

(A)	(B)	(C)	(D)	(E)
Line		Balances @ 12/31/2010	Balances @ 12/31/2009	Average
Development of Average Balance of Common Equity				
1	Proprietary Capital (112.16.c&d)	1,486,215,163	1,359,835,152	1,423,025,158
2	Less Preferred Stock (Ln 55 Below)	0	0	-
3	Less Account 216.1 (112.12.c&d)	2,134,800	2,064,800	2,099,800
4	Less Account 219.1 (112.15.c&d)	(51,335,895)	(49,993,531)	(50,664,713)
5	Average Balance of Common Equity	1,535,416,258	1,407,763,883	1,471,590,071

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)	-	-	-
8	LT Advances from Assoc. Companies (112.20.c&d)	-	100,000,000	50,000,000
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	Total Average Debt	1,442,745,000	1,542,745,000	1,492,745,000

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 2010			
14	Interest on Long Term Debt (256-257.33.i)			83,196,386
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)			1,862,634
18	Amort of Loss on Reacquired Debt (117.64.c)			743,541
19	Less: Amort of Premium on Debt (117.65.c)			-
20	Less: Amort of Gain on Reacquired Debt (117.66.c)			-
21	Total Interest Expense (Ln 14 + Ln 17 + Ln 18 - Ln 19 - Ln 20)			85,802,561
22	Average Cost of Debt for 2010 (Ln 21/Ln 11)			5.75%

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 2010	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 2010 (True-UP TCOS, Ln 165)			2,964,335,071		
37 Financial Hedge Recovery Limit - Five Basis Points of Total Capital			0.0005		
38 Limit of Recoverable Amount			1,482,168		
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 2010 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 funtionalized based on the description of that asset. Sales of transmission assets will be direct assigned; sales of general assets will be functionalized on labor. Sales of plant held for future use related to generation or distribution will not be included in the formula.

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 2010	- =====		- =====	

AEP East Companies
Cost of Service Formula Rate Using 2010 FF1 Balances
Worksheet O - Calculation of Postemployment Benefits Other than Pensions Expenses Allocable to Transmission Service
COLUMBUS SOUTHERN POWER COMPANY

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

Allocation of PBOP Settlement Amount for 2010

Total Company Amount

Line#	Company	Actual Expense (Including AEPSC Billed OPEB)	Ratio of Company Actual to Total	Allocation of PBOP Recovery Allowance	Labor Allocator for 2010	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	13,207,032	26.27%	12,637,155	7.489%	989,110	946,430	42,680
2	CSP	7,759,634	15.44%	7,424,809	5.961%	462,523	442,566	19,958
3	I&M	13,602,157	27.06%	13,015,230	5.208%	708,440	677,872	30,569
4	KPCo	2,592,156	5.16%	2,480,306	9.956%	258,065	246,930	11,135
5	KNGP	386,298	0.77%	389,629	8.357%	32,284	30,891	1,393
6	OPCo	12,241,700	24.35%	11,713,476	9.182%	1,123,972	1,075,473	48,499
7	WPCo	480,113	0.96%	459,397	5.436%	26,101	24,975	1,126
8	Sum of Lines 1 to 7	50,269,090		48,100,000		3,600,497	3,445,137	155,360

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	20,529,721	9,778,864	16,755,046	3,346,838	482,787	16,248,955	616,268	67,758,479
10 Additional PBOP Ledger Entries (from Company Records)	(2,695,814)	-	534,099	(1)	1	(443,953)	1	
11 Medicare Subsidy	(5,735,375)	(2,596,761)	(4,476,103)	(954,918)	(128,004)	(4,530,395)	(163,291)	(18,584,847)
12 Net Company Expense (Ln 9 + Ln 10 + Ln 11)	12,098,532	7,182,103	12,813,042	2,391,919	354,784	11,274,607	452,978	46,567,965
13 PBOP Expenses From AEP Service Corporation (from Company Records)	1,108,500	577,531	789,115	200,237	31,514	967,093	27,135	3,701,125
14 Company PBOP Expense (Ln 12 + Ln 13)	13,207,032	7,759,634	13,602,157	2,592,156	386,298	12,241,700	480,113	50,269,090

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

	PLANT ACCT.	RATES Note 1
<i>TRANSMISSION PLANT</i>		
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.