Twelve Months Ended 2019

AEP East Companies
Transmission Cost of Service Formula Rate
Utilizing Actual/Projected FERC Form 1 Data

Ohio Power Company

Line No.			Total	Allocator			Transmission Amount
1	REVENUE REQUIREMENT (w/o incentives)	(ln 130)					$316,090,247
2	REVENUE CREDITS	(Worksheet E Ln 8) (Note A)	11,166,000	DA	1.00000	$	11,166,000
3	Facility Credits under PJM OATT Section 30.9	(Worksheet E Ln 9) (Note X)				$	4,028,356
4	REVENUE REQUIREMENT For All Company Facilities	(ln 1 less ln 2 plus ln 3)				$	308,952,603

MEMO: The Carrying Charge Calculations on lines 7 to 12 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 5 is included in the total on line 4.

Line No.			Total	Allocator			Transmission Amount
5	Revenue Requirement for PJM Schedule 12 Facilities (w/o incentives) (Worksheet J/K)		10,202,114	DA	1.00000	$	10,202,114
6	NET PLANT CARRYING CHARGE w/o intra-AEP charges or credits or ROE incentives (Note B)						
7	Annual Rate	((ln 1 - ln 95)/((ln 42) x 100))					18.61%
8	Monthly Rate	(ln 7 / 12)					1.55%
9	NET PLANT CARRYING CHARGE ON LINE 7 , w/o depreciation or ROE incentives (Note B)						
10	Annual Rate	((ln 1 - ln 95 - ln 100) /((ln 42) x 100))					15.02%
11	NET PLANT CARRYING CHARGE ON LINE 10, w/o Return, income taxes or ROE incentives (Note B)						
12	Annual Rate	((ln 1 - ln 95 - ln 100 - ln 125 - ln 126) /((ln 42) x 100))					7.51%
13	ADDITIONAL REVENUE REQUIREMENT for projects w/ incentive ROE's (Note B) (Worksheet J/K)						

Line No.			
14	**REVENUE REQUIREMENT FOR SCHEDULE 1A CHARGES**		
15	Total Load Dispatch & Scheduling (Account 561)	Line 75 Below	6,363,000
16	Less: Load Dispatch - Scheduling, System Control and Dispatch Services (321.88.b)		107,000
17	Less: Load Dispatch - Reliability, Planning & Standards Development Services (321.92.b)		1,000
18	Total 561 Internally Developed Costs	(Line 15 - Line 16 - Line 17)	6,255,000

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Line No.	(1) RATE BASE CALCULATION	(2) Data Sources (See "General Notes")	(3) TO Total NOTE C	(4) Allocator		(5) Total Transmission
	GROSS PLANT IN SERVICE					
19	Production	(Worksheet A ln 14.(b))	-	NA	0.00000	-
20	Less: Production ARO (Enter Negative)	(Worksheet A ln 14.(c))	-	NA	0.00000	-
21	Transmission	(Worksheet A ln 14.(d) & TCOS Ln 134)	2,633,166,462	DA		2,633,166,462
22	Less: Transmission ARO (Enter Negative)	(Worksheet A ln 14.(e))	(3,000)	TP	1.00000	(3,000)
23	Distribution	(Worksheet A ln 14.(f))	5,250,043,154	NA	0.00000	-
24	Less: Distribution ARO (Enter Negative)	(Worksheet A ln 14.(g))	-	NA	0.00000	-
25	General Plant	(Worksheet A ln 14.(h))	409,076,154	W/S	0.11590	47,410,477
26	Less: General Plant ARO (Enter Negative)	(Worksheet A ln 14.(i))	(613,000)	W/S	0.11590	(71,045)
27	Intangible Plant	(Worksheet A ln 14.(j))	176,079,462	W/S	0.11590	20,406,986
28	TOTAL GROSS PLANT	(sum lns 19 to 27)	8,467,749,231	**GP**	**0.318964**	2,700,909,880
				GTD=	**0.33402**	
29	ACCUMULATED DEPRECIATION AND AMORTIZATION					
30	Production	(Worksheet A ln 28.(b))	-	NA	0.00000	-
31	Less: Production ARO (Enter Negative)	(Worksheet A ln 28.(c))	-	NA	0.00000	-
32	Transmission	(Worksheet A ln 28.(d) & ln 43.(c))	949,049,077	**TP1=**	1.00000	949,049,077
33	Less: Transmission ARO (Enter Negative)	(Worksheet A ln 28.(e))	(3,000)	**TP1=**	1.00000	(3,000)
34	Distribution	(Worksheet A ln 28.(f))	1,709,614,308	NA	0.00000	-
35	Less: Distribution ARO (Enter Negative)	(Worksheet A ln 28.(g))	-	NA	0.00000	-
36	General Plant	(Worksheet A ln 28.(h))	110,843,385	W/S	0.11590	12,846,356
37	Less: General Plant ARO (Enter Negative)	(Worksheet A ln 28.(i))	(270,000)	W/S	0.11590	(31,292)
38	Intangible Plant	(Worksheet A ln 28.(j))	90,475,538	W/S	0.11590	10,485,794
39	TOTAL ACCUMULATED DEPRECIATION	(sum lns 30 to 38)	2,859,709,308			972,346,935
40	NET PLANT IN SERVICE					
41	Production	(ln 19 + ln 20 - ln 30 - ln 31)	-			-
42	Transmission	(ln 21 + ln 22 - ln 32 - ln 33)	1,684,117,385			1,684,117,385
43	Distribution	(ln 23 + ln 24 - ln 34 - ln 35)	3,540,428,846			-
44	General Plant	(ln 25 + ln 26 - ln 36 - ln 37)	297,889,769			34,524,369
45	Intangible Plant	(ln 27 - ln 38)	85,603,923			9,921,191
46	TOTAL NET PLANT IN SERVICE	(sum lns 41 to 45)	5,608,039,923	**NP**	**0.308229**	1,728,562,945
47	DEFERRED TAX ADJUSTMENTS TO RATE BASE	(Note D)				
48	Account No. 281.1 (enter negative)	(Worksheet B, ln 2 & ln 5.E)	-	NA		-
49	Account No. 282.1 (enter negative)	(Worksheet B, ln 7 & ln 10.E)	(793,911,984)	DA		(393,108,867)
50	Account No. 283.1 (enter negative)	(Worksheet B, ln 12 & ln 15.E)	(156,541,524)	DA		(24,621,283)
51	Account No. 190.1	(Worksheet B, ln 17 & ln 20.E)	217,829,457	DA		12,412,635
52	Account No. 255 (enter negative)	(Worksheet B, ln 24 & ln 25.E)	21,899	DA		(11,952)
53	TOTAL ADJUSTMENTS	(sum lns 48 to 52)	(732,602,152)			(405,329,468)
54	PLANT HELD FOR FUTURE USE	(Worksheet A ln 44.(e) & ln 45.(e))	5,932,000	DA		1,704,000
55	REGULATORY ASSETS	(Worksheet A ln 51.(e))	-	DA		-
56	UNFUNDED RESERVES (ENTER NEGATIVE) (NOTE Y)	(Worksheet A ln 54.(e))	(253,000)	W/S	0.11590	(29,322)
57	WORKING CAPITAL	(Note E)				
58	Cash Working Capital	(1/8 * ln 78)	3,900,000			3,900,000
59	Transmission Materials & Supplies	(Worksheet C, ln 2.(F))	4,268,000	TP	1.00000	4,268,000
60	A&G Materials & Supplies	(Worksheet C, ln 3.(F))	-	W/S	0.11590	-
61	Stores Expense	(Worksheet C, ln 4.(F))	-	GP	0.31896	-
62	Prepayments (Account 165) - Labor Allocated	(Worksheet C, ln 8.G)	187,275,557	W/S	0.11590	21,704,574
63	Prepayments (Account 165) - Gross Plant	(Worksheet C, ln 8.F)	1,976,995	GP	0.31896	630,591
64	Prepayments (Account 165) - Transmission Only	(Worksheet C, ln 8.E)	(213,939)	DA	1.00000	(213,939)
65	Prepayments (Account 165) - Unallocable	(Worksheet C, ln 8.D)	(176,245,112)	NA	0.00000	-
66	TOTAL WORKING CAPITAL	(sum lns 58 to 65)	20,961,501			30,289,225
67	IPP CONTRIBUTIONS FOR CONSTRUCTION	(Note F) (Worksheet D, ln 8.B)	-	DA	1.00000	-
68	RATE BASE (sum lns 46, 53, 54, 55, 56, 66, 67)		4,902,078,272			1,355,197,381

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Line No.	(1) EXPENSE, TAXES, RETURN & REVENUE REQUIREMENTS CALCULATION	(2) Data Sources (See "General Notes")	(3) TO Total	(4) Allocator		(5) Total Transmission
	OPERATION & MAINTENANCE EXPENSE					
69	Production	321.80.b	902,664,000			
70	Distribution	322.156.b	156,047,000			
71	Customer Related Expense	322 & 323.164,171,178.b	230,335,000			
72	Regional Marketing Expenses	322.131.b				
73	Transmission	321.112.b	386,487,000			
74	TOTAL O&M EXPENSES	(sum lns 69 to 73)	1,675,533,000			
75	Less: Total Account 561	(Note G) (Worksheet F, ln 14.C)	6,363,000			
76	Less: Account 565	(Note H) 321.96.b	348,924,000			
77	Less: Regulatory Deferrals & Amortizations	(Note I) (Worksheet F, ln 4.C)	-			
78	Total O&M Allocable to Transmission	(lns 73 - 75 - 76 - 77)	31,200,000	TP	1.00000	31,200,000
79	Administrative and General	323.197.b (Notes J and M)	64,643,000			
80	Less: Acct. 924, Property Insurance	323.185.b	1,795,000			
81	Acct. 9260039 PBOP Expense	PBOP Worksheet O Line 9 & 10, (Note K)	(7,014,204)			
82	Acct. 9260057 PBOP Medicare Subsidy	PBOP Worksheet O Line 11, (Note K)	-			
83	PBOP Expense Billed From AEPSC	PBOP Worksheet O Line 13, (Note K)	(690,642)			
84	Acct. 928, Reg. Com. Exp.	323.189.b	1,024,000			
85	Acct. 930.1, Gen. Advert. Exp.	323.191.b	229,000			
86	Acct. 930.2, Misc. Gen. Exp.	323.192.b	(763,000)			
87	Balance of A & G	(ln 79 - sum ln 80 to ln 86)	70,062,846	W/S	0.11590	8,120,036
88	Plus: Acct. 924, Property Insurance	(ln 80)	1,795,000	GP	0.31896	572,541
89	Acct. 928 - Transmission Specific	Worksheet F ln 20.(E) (Note L)	81,238	TP	1.00000	81,238
90	Acct 930.1 - Only safety related ads -Direct	Worksheet F ln 37.(E) (Note L)	-	TP	1.00000	-
91	Acct 930.2 - Misc Gen. Exp. - Trans	Worksheet F ln 43.(E) (Note L)	488,000	DA	1.00000	488,000
92	Settlement Approved PBOP Recovery	PBOP Worksheet O, Col. C (Note M)	(32,623,461)	W/S	0.11590	(3,780,944)
93	A & G Subtotal	(sum lns 87 to 92)	39,803,623			5,480,871
94	O & M EXPENSE SUBTOTAL	(ln 78 + ln 93)	71,003,623			36,680,871
95	Plus: Transmission Lease Payments To Affiliates in Acct 565 (Company Records) (Note H)		2,704,000	DA	1.00000	2,704,000
96	TOTAL O & M EXPENSE	(ln 94 + ln 95)	73,707,623			39,384,871
97	DEPRECIATION AND AMORTIZATION EXPENSE					
98	Production	336.2-6.f	-	NA	0.00000	-
99	Distribution	336.8.f	185,612,000	NA	0.00000	-
100	Transmission	336.7.f	60,448,000	TP1	1.00000	60,448,000
101	General	336.10.f	9,907,000	W/S	0.11590	1,148,186
102	Intangible	336.1.f	32,415,000	W/S	0.11590	3,756,784
103	TOTAL DEPRECIATION AND AMORTIZATI0N	(Ln 98+99+ 100+101+102)	288,382,000			65,352,970
104	TAXES OTHER THAN INCOME	(Note N)				
105	Labor Related					
106	Payroll	Worksheet H ln 24.(D)	6,427,000	W/S	0.11590	744,867
107	Plant Related					
108	Property	Worksheet H-1 ln 3.(C) & 3.(G)	266,948,000	DA		82,946,493
109	Gross Receipts/Sales & Use	Worksheet H ln 24.(F)	141,116,000	NA	0.00000	-
110	Other	Worksheet H ln 24.(E)	3,701,000	GP	0.31896	1,180,487
111	TOTAL OTHER TAXES	(sum lns 106 to 110)	418,192,000			84,871,846
112	INCOME TAXES	(Note O)				
113	T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =		21.84%			
114	EIT=(T/(1-T)) * (1-(WCLTD/WACC)) =		19.72%			
115	where WCLTD=(ln 154) and WACC = (ln 157)					
116	and FIT, SIT & p are as given in Note O.					
117	GRCF=1 / (1 - T) = (from ln 113)		1.2795			
118	Amortized Investment Tax Credit (enter negative)	(FF1 p.114, ln 19.c)	(1,000)			
119	Excess Deferred Income Tax	(Note U)	(24,608,973)	DA		(5,220,442)
120	Tax Effect of Permanent and Flow-Through Differences	(Note U)	2,555,424	DA		1,815,564
121	Income Tax Calculation	(ln 114 * ln 126)	77,940,499			21,546,935
122	ITC adjustment	(ln 117 * ln 118)	(1,279)	GP	0.31896	(408)
123	Excess Deferred Income Tax	(ln 117 * ln 119)	(31,486,369)			(6,679,383)
124	Tax Effect of Permanent and Flow-Through Differences	(ln 117 * ln 120)	3,269,581			2,322,954
125	TOTAL INCOME TAXES	(sum lns 121 to 124)	49,722,431			17,190,097
126	RETURN ON RATE BASE (Rate Base*WACC)	(ln 68 * ln 157)	395,330,163			109,290,462
127	INTEREST ON IPP CONTRIBUTION FOR CONST. (Note F) (Worksheet D, ln 2.(B))		-	DA	1.00000	-
128	(Gains) / Losses on Sales of Plant Held for Future Use (Worksheet N, ln 4, Cols. ((F) & (H))		-			-
129	Tax Impact on Net Loss / (Gain) on Sales of Plant Held for Future Use (ln 128 * ln114)		-			-
130	TOTAL REVENUE REQUIREMENT (sum lns 96, 103, 111, 125, 126, 127, 128, 129)		1,225,334,216			316,090,247

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SUPPORTING CALCULATIONS

ln No.								
	TRANSMISSION PLANT INCLUDED IN PJM TARIFF							
131	Total transmission plant	(ln 21)						2,633,166,462
132	Less transmission plant excluded from PJM Tariff (Worksheet A, ln 42, Col. (d)) (Note P)							-
133	Less transmission plant included in OATT Ancillary Services (Worksheet A, ln 42, Col. (b)) (Note Q)							-
134	Transmission plant included in PJM Tariff	(ln 131 - ln 132 - ln 133)						2,633,166,462
135	Percent of transmission plant in PJM Tariff	(ln 134 / ln 131)					**TP=**	**1.00000**
				Payroll Billed from				
136	WAGES & SALARY ALLOCATOR (W/S)	(Note R)	Direct Payroll	AEP Service Corp.	Total			
137	Production	354.20.b	31,304	96,119	127,423	NA	0.00000	-
138	Transmission	354.21.b	389,201	11,077,796	11,466,997	TP	1.00000	11,466,997
139	Regional Market Expenses	354.22.b	0	0	-	NA	0.00000	-
140	Distribution	354.23.b	47,066,173	8,658,493	55,724,666	NA	0.00000	-
141	Other (Excludes A&G)	354.24,25,26.b	16,987,857	14,634,796	31,622,653	NA	0.00000	-
142	Total	(sum lns 137 to 141)	64,474,535	34,467,204	98,941,739			11,466,997
143	Transmission related amount						**W/S=**	**0.11590**
144	WEIGHTED AVERAGE COST OF CAPITAL (WACC)							$
145	Long Term Interest	(Worksheet M, ln. 37, col. (d))						109,341,000
146	Preferred Dividends	(Worksheet M, ln. 71)						-
147	Development of Common Stock:							
148	Proprietary Capital	(Worksheet M, ln. 14, col. (b))						2,531,012,923
149	Less: Preferred Stock	(Worksheet M, ln. 14, col. (c))						-
150	Less: Account 216.1	(Worksheet M, ln. 14, col. (d))						-
151	Less: Account 219	(Worksheet M, ln. 14, col. (e))						714,615
152	Common Stock	(ln 148 - ln 149 - ln 150 - ln 151)						2,530,298,308
					Capital Structure Percentages		Cost	
153				$	Actual	Cap Limit	(Note S)	Weighted
154	Long Term Debt (Note T) Worksheet M, ln 28, col. (g), ln 38, col. (d))			2,072,900,154	45.03%	45.03%	5.27%	0.0238
155	Preferred Stock (ln 149)			-	0.00%	0.00%	-	0.0000
156	Common Stock (ln 152)			2,530,298,308	54.97%	54.97%	10.35%	0.0569
157	Total (Sum lns 154 to 156)			4,603,198,462			**WACC=**	**0.0806**
158	Capital Structure Equity Limit (Note Z)	55%						

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Letter	Notes
	General Notes: a) References to data from Worksheets are indicated as: Worksheet X, Line#.Column.X
A	Revenue credits include: 1) Forfeited Discounts. 2) Miscellaneous Service Revenues. 3) Rental revenues earned on assets included in the rate base. 4) Revenues for associated business projects provided by employees whose labor and overhead costs are in the transmission cost of service. 5) Other electric revenues. 6) Revenues for grandfathered PTP contracts included in the load divisor. 7) If AEP East companies have any directly assigned transmission facilities, the revenue credits in the AEP East formula rate shall include all revenues associated with those directly assigned transmission facilities, irrespective of whether the loads of the customer are included in the formula rate divisor; provided however, such addition to revenue credits shall not be reflected if the costs of such directly assigned transmission facilities are not included in the transmission plant balances on which the formula rate ATRR is based. 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. Interest will be calculated based on Worksheet Q and any over under recovery will be filed and posted as part of the informational filing.
C	Transmission Plant Balances in this study are projected or actual average of 13-month balances.
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 flowthrough 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 the calculation of ADIT in the annual projection will be performed in accordance with IRS regulation Section1.167(l)-l(h)(6)(ii). 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. Detailed balances for the projected or actual period, distinguished between utility and non-utility balances, will be filed and posted as part of the information filing.
E	Cash Working Capital assigned to transmission is one-eighth of O&M allocated to transmission, as shown on line 78. It excludes: 1) Load Scheduling & Dispatch Charges in account 561 that are collected in the OATT Ancillary Services Revenue, as shown on line 75. 2) Costs of Transmission of Electricity by Others, as described in Note H. 3) The impact of state regulatory deferrals and amortizations, as shown on line 77 4) All A&G Expenses, as shown on line 93.
F	Consistent with Paragraph 657 of Order 2003-A, the amount on line 67 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 127.
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 16 & 17 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 78. To the extent such service is incurred to provide the PJM service at issue, e.g. lease payments to affiliates, such cost is added back on line 95 to determine the total O&M collected in the formula. The amounts on line 95 is also excluded in the calculation of the FCR percentage calculated on lines 6 through 12. The addbacks on line 95 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 line 95 is the Ohio Power Company general ledger.
I	Removes the impact of state regulatory deferrals or their amortization from Transmission 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 81 through 83 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 recorded in FERC Accounts 928 (Regulatory Commission Expense), 930.1 (Safety Related Advertising) and 930.2 (Miscellaneouse General Expenses) that are not directly related to or properly allocable to transmission service will be removed from the TCOS. If AEP includes any expenses booked to these accounts in future ATRR updates, AEP must provide supporting information demonstrating that the underlying activities are directly related to providing transmission service. Account 930.2 includes the expenses incurred by the transmission function for Associated Business Development revenues given as a credit to the TCOS on Worksheet E.
M	See note K above. Per the settlement in Docket ER08-1329, recoverable PBOP expense is based on an annual total for the operating companies that is ratioed to them based on the total of actual annual PBOP costs, including charges from the AEP Service Corportation. The calculation of the recoverable amount for each company is shown on Worksheet O.
N	Includes only FICA, unemployment, highway, property and other assessments charged in the current year. Gross receipts, sales & use and taxes related to income are excluded.
O	The currently effective income tax rate, where FIT is the Federal income tax rate; SIT is the State income tax rate, and p = the percentage of federal income tax deductible for state income taxes. See Worksheet G for the development of the Company's composite SIT. A utility that elected to utilize amortization of tax credits against taxable income, rather than book tax credits to Account No. 255 and reduce rate base, must reduce its income tax expense by the amount of the Amortized Investment Tax Credit (Form 1, 266.8.f) (ln 118) multiplied by (1/1-T) . If the applicable tax rates are zero enter 0. Inputs Required: FIT = 21.00% SIT= 1.07% (State Income Tax Rate or Composite SIT. Worksheet G)) p = 0.00% (percent of federal income tax deductible for state purposes) The formula rate shall reflect the applicable state and federal statutory tax rates in effect during the period the calculated estimated unit charges are applicable. If the statutory tax rates change during such period, the effective tax rates used in the formula shall be weighted by the number of days the pre-change rate and post-change rate each is in effect.
P	Removes plant excluded from the OATT because it does not meet the PJM's definition of Transmission Facilities or is otherwise ineligible to be recovered under the OATT.
Q	Removes transmission plant (e.g. step-up transformers) included in the development of OATT ancillary service rates and not already removed for reasons indicated in Note P.
R	Includes functional wages & salaries billed by AEP Service Corporation for support of the operating company.
S	Long Term Debt cost rate = Long-Term Interest (ln 145) / Long-Term Debt (ln 154). Preferred Stock cost rate = preferred dividends (ln 146) / preferred outstanding (ln 155). Common Stock cost rate (ROE) = 10.35%, per the Settlement in FERC Docket No. EL17-13. It includes an additional 50 basis points for PJM RTO Membership. The amount of eligible hedging gains or losses included in total interest expense is limited to five basis points of the capital structure. Details and calculations of the weighted average cost of captial are shown on Worksheet M. Eligible Hedging Gains and Losses are computed on Worksheet M.The unamortized balance of eligible hedge gains/losses and related ADIT amounts shall not flow through the formula rate.
T	The Long Term Debt balance for I&M includes the accumulated balance of principle and related interest for Spent Nuclear Fuel Disposal Costs collected prior to April 7, 1983. This total balance of $265,249,280 at 12/31/12 is not included in the balance in line 154 above. The cost rates for long-term debt shall include interest expense and related periodic expenses (such as remarketing and letter of credit fees) as recorded in FERC Account 427 or 430, amortization of issuance costs (including insurance) and discounts as recorded in FERC Account 428, issuance premiums as recorded in FERC Account 429 and losses or gains on reacquired debt as recorded in FERC Accounts 428.1 or 429.1, respectively. The cost rates for preferred stock (if applicable) shall include the dividends.
U	Excess / (Deficit) Deferred Income Taxes will be amortized over the average remaining life of the assets to which it relates, unless the Commission requires a different amortization period. The Tax Effect of Permanent Differences captures the differences in the income taxes due under the Federal and State tax calculations that are not the result of a timing difference, including but not limited to depreciation related to capitalized AFUDC equity and meals and entertainment deductions. The Tax Effect of Flow-Through differences captures current tax expense related to timing differences on items for which tax deductions were used to reduce customer rates through the use of flow-through accounting in a prior period. Transmission balances for the projected or actual period, will be filed and posted as part of the informational filing.
V	Cash investment in prepaid pension and benefits recorded in FERC Account 165 is permitted to be included in the formula. A labor expense allocation factor will be used to allocate total company costs. All other prepayments recorded in FERC Account 165 are directly assigned to the transmission function, allocated or excludable balances detailed on Worksheet C.
W	The formula rate shall allocate property tax expense based on the as filed net plant cost allocation method detailed on Worksheet H.
X	Under Section 30.9 of the PJM OATT, a network customer that owns existing transmission facilities that are integrated with the Transmission Provider's Transmission System may be eligible to receive consideration either through a billing credit or some other mechanism. Calculation of any credit under this subsection, pursuant to approval by FERC for inclusion in this formula rate for collection on behalf of the network customer, shall be addressed in either the Network Customer's Service Agreement or any other agreement between the parties.
Y	The cost of service will make a rate base adjustment to remove unfunded reserves associated with contingent liabilites recorded to Accounts 228.1-228.4 from rate base.
Z	Per the settlement in EL17-13, equity is limited to 55% in of the Company's capital structure. If the percentage of actual equity exceeds the cap, the excess is included as long term debt in the capital structure.

AEP East Companies
Cost of Service Formula Rate Using Actual/Projected FF1 Balances
Worksheet A Rate Base
Ohio Power Company

Line No	Month (a)	Production (b)	Production ARO (c)	Transmission (d)	Transmission ARO (e)	Distribution (f)	Distribution ARO (g)	General (h)	General ARO (i)	Intangible (j)
		Gross Plant In Service								
	(Note A)	FF1, page 205 Col.(g) & pg. 204 Col. (b), ln 46	FF1, page 205&204, Col.(g)&(b), lns 15,24,34,44	FF1, page 207 Col.(g) & pg. 206 Col. (b), ln 58	Acct. 359.1 FF1, page 207 Col.(g) & pg. 206 Col. (b), ln 57	FF1, page 207 Col.(g) & pg. 206 Col. (b), ln 75	FF1, page 207 Col.(g) & pg. 206 Col. (b), ln 74	FF1, page 207 Col.(g) & pg. 206 Col. (b), ln 99	Acct. 399.1 FF1, page 207 Col.(g) & pg. 206 Col. (b), ln 98	FF1, page 205 Col.(g) & pg. 204 Col. (b), ln 5
1	December Prior to Rate Year	-	-	2,580,386,000	3,000	5,062,525,000		380,537,000	613,000	163,136,000
2	January	-	-	2,585,202,000	3,000	5,094,747,000		381,009,000	613,000	170,272,000
3	February	-	-	2,587,467,000	3,000	5,120,123,000		381,563,000	613,000	175,762,000
4	March	-	-	2,590,821,000	3,000	5,161,595,000		393,383,000	613,000	178,938,000
5	April	-	-	2,599,466,000	3,000	5,183,116,000		394,021,000	613,000	181,938,000
6	May	-	-	2,617,554,000	3,000	5,208,685,000		394,661,000	613,000	184,990,000
7	June	-	-	2,636,661,000	3,000	5,254,208,000		412,160,000	613,000	166,109,000
8	July	-	-	2,643,042,000	3,000	5,281,363,000		413,254,000	613,000	169,296,000
9	August	-	-	2,650,243,000	3,000	5,310,323,000		414,422,000	613,000	172,464,000
10	September	-	-	2,659,915,000	3,000	5,338,452,000		415,589,000	613,000	175,633,000
11	October	-	-	2,671,288,000	3,000	5,372,927,000		416,267,000	613,000	179,261,000
12	November	-	-	2,678,821,000	3,000	5,410,878,000		416,947,000	613,000	183,353,000
13	December of Rate Year	-	-	2,730,298,000	3,000	5,451,619,000		504,177,000	613,000	187,881,000
14	Average of the 13 Monthly Balances	-	-	2,633,166,462	3,000	5,250,043,154	-	409,076,154	613,000	176,079,462

Line No	Month (a)	Production (b)	Production ARO (c)	Transmission (d)	Transmission ARO (e)	Distribution (f)	Distribution ARO (g)	General (h)	General ARO (i)	Intangible (j)
		Accumulated Depreciation								
	(Note A)	FF1, page 219, lns 20-24, Col. (b)	Company Records (Included in total in Column (b))	FF1, page 219, ln 25, Col. (b)	Company Records (Included in total in Column (d))	FF1, page 219, ln 26, Col. (b)	Company Records (Included in total in Column (f))	FF1, page 219, ln 28, Col. (b)	Company Records (Included in total in Column (h))	FF1, page 200, ln 21, Col. (b)
15	December Prior to Rate Year	-	-	936,953,000	3,000	1,661,835,000		108,993,000	270,000	86,178,000
16	January	-	-	938,856,000	3,000	1,669,472,000		109,272,000	270,000	88,714,000
17	February	-	-	940,769,000	3,000	1,677,197,000		109,552,000	270,000	91,361,000
18	March	-	-	942,687,000	3,000	1,685,035,000		109,833,000	270,000	94,094,000
19	April	-	-	944,611,000	3,000	1,692,913,000		110,141,000	270,000	96,876,000
20	May	-	-	947,132,000	3,000	1,700,895,000		110,450,000	270,000	99,704,000
21	June	-	-	949,109,000	3,000	1,708,983,000		110,760,000	270,000	80,589,000
22	July	-	-	951,125,000	3,000	1,717,149,000		111,108,000	270,000	83,132,000
23	August	-	-	953,153,000	3,000	1,725,391,000		111,460,000	270,000	85,723,000
24	September	-	-	955,196,000	3,000	1,733,741,000		111,813,000	270,000	88,363,000
25	October	-	-	957,259,000	3,000	1,742,188,000		112,169,000	270,000	91,051,000
26	November	-	-	959,344,000	3,000	1,750,752,000		112,527,000	270,000	93,795,000
27	December of Rate Year	-	-	961,444,000	3,000	1,759,435,000		112,886,000	270,000	96,602,000
28	Average of the 13 Monthly Balances	-	-	949,049,077	3,000	1,709,614,308	-	110,843,385	270,000	90,475,538

Line No	Month (a) (Note A)	OATT Ancillary Services (GSU) Plant In Service (b) Company Records (included in total in column (d) of gross plant above)	OATT Ancillary Services (GSU) Accumulated Depreciation (c) Company Records (included in total in column (b) of accumulated depreciation above)	Excluded Plant - Plant In Service (d) Company Records	Excluded Plant - Accumulated Depreciation (e) Company Records
29	December Prior to Rate Year				
30	January				
31	February				
32	March				
33	April				
34	May				
35	June				
36	July				
37	August				
38	September				
39	October				
40	November				
41	December of Rate Year				
42	Average of the 13 Monthly Balances	-	-	-	-

43	Transmission Accum Depreciation net of GSU		949,049,077		

	Plant Held For Future Use (a)	Source of Data (b)	Balance @ December 31, 2019 (c)	Balance @ December 31, 2018 (d)	Average Balance for 2019 (e)
44	**Plant Held For Future Use**	FF1, page 214, ln 47, Col. (d)	5,932,000	5,932,000	5,932,000
45	**Transmission Plant Held For Future Use (Included in total on line 44)**	Company Records - Note 1	-	3,408,000	1,704,000

Regulatory Assets and Liabilities Approved for Recovery In Ratebase

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

46					-
47					-
48					-
49					-
50					-
51	Total Regulatory Deferrals Included in Ratebase		-	-	-

Unfunded Reserves Summary (Company Records)

52	Description	Account			
53a	Accum Prv I/D Worker's Com		253,000	253,000	253,000
53b					-
54		Total	253,000	253,000	253,000

NOTE 1: On this worksheet, "Company Records" refers to AEP's property accounting ledger.
NOTE 2: The ratebase should not include the unamortized balance of hedging gains or losses.

AEP East Companies
Cost of Service Formula Rate Using Actual/Projected FF1 Balances
Worksheet B Supporting ADIT and ITC Balances
Ohio Power Company

Line Number	(A) Description	(B) Source	(C) Balance @ December 31, 2019	(D) Balance @ December 31, 2018	(E) Average Balance for 2019
1	**Account 281**				
2	Year End Utility Deferrals	FF1, p. 272 - 273, ln 8, Col. (k)	-	-	-
3	Less: ARO Related Deferrals	WS B-1 - Actual Stmt. AF Ln. 4 (Note 1)	-	-	-
4	Less: Other Excluded Deferrals	WS B-1 - Actual Stmt. AF Ln. 3 (Note 1)	-	-	-
5	Transmission Related Deferrals	Ln 2 - ln 3 - ln 4	-	-	-
6	**Account 282**				
7	Year End Utility Deferrals	FF1, p. 274 - 275, ln 5, Col. (k)	809,189,899	778,634,068	793,911,984
8	Less: ARO Related Deferrals	WS B-1 - Actual Stmt. AF Ln. 7 (Note 1)	580,593	580,593	580,593
9	Less: Other Excluded Deferrals	WS B-1 - Actual Stmt. AF Ln. 6 (Note 1)	413,234,515	387,210,532	400,222,523
10	Transmission Related Deferrals	Ln 7 - ln 8 - ln 9	395,374,791	390,842,944	393,108,867
11	**Account 283**				
12	Year End Utility Deferrals	FF1, p. 276 - 277, ln 9, Col. (k)	158,189,435	154,893,613	156,541,524
13	Less: ARO Related Deferrals	WS B-1 - Actual Stmt. AF Ln. 13 (Note 1)	-	-	-
14	Less: Other Excluded Deferrals	WS B-1 - Actual Stmt. AF Ln. 12 (Note 1)	133,412,171	130,428,311	131,920,241
15	Transmission Related Deferrals	Ln 12 - ln 13 - ln 14	24,777,264	24,465,301	24,621,283
16	**Account 190**				
17	Year End Utility Deferrals	FF1, p. 234, ln 8, Col. (c)	217,829,457	217,829,457	217,829,457
18	Less: ARO Related Deferrals	WS B-2 - Actual Stmt. AG Ln. 4 (Note 1)	497,910	497,910	497,910
19	Less: Other Excluded Deferrals	WS B-2 - Actual Stmt. AG Ln. 3 (Note 1)	204,918,912	204,918,912	204,918,912
20	Transmission Related Deferrals	Ln 17 - ln 18 - ln 19	12,412,635	12,412,635	12,412,635
21	**Account 255**				
22	Year End ITC Balances	FF1, p. 266-267, ln 8, Col. (h)	(3,000)	2,000	(500)
23	Less: Balances Not Qualified for Ratebase	Company Records - Note 1	21,399	21,399	21,399
24	ITC Balances Includeable Ratebase	Ln 22 - ln 23	(24,399)	(19,399)	(21,899)
25	Transmission Related Deferrals	WS B-1 - Actual Stmt. AF Ln. 20 (Note 1)	11,952	11,952	11,952

NOTE 1 On this worksheet, "Company Records" refers to AEP's tax forecast and accounting ledger. The PTRR will use projected ending balances and reflect proration required by IRS Letter Rule Section I.I67(I)-I(h)(6)(ii). Line item detail of actual deferred tax items will be included on Worksheets B-1 and B-2.

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

Ohio Power Company
SPECIFIED DEFERRED CREDITS - Actual Cycle Only
PERIOD ENDED DECEMBER 31, 2019

(DEBIT) CREDIT

	COLUMN A	COLUMN B	COLUMN C	COLUMN D	COLUMN E	COLUMN F	COLUMN G	COLUMN H	COLUMN I	COLUMN J	COLUMN K	COLUMN L	COLUMN M	COLUMN N	COLUMN O
		PER BOOKS		NON-APPLICABLE/NON-UTILITY		AVERAGE	FUNCTIONALIZATION AVERAGE			FUNCTIONALIZATION 12/31/2018			FUNCTIONALIZATION 12/31/2019		
	ACCUMULATED DEFERRED FIT ITEMS	BALANCE AS OF 12-31-2018	BALANCE AS OF 12-31-2019	BALANCE AS OF 12-31-2018	BALANCE AS OF 12-31-2019	ELECTRIC UTILITY (B+C+D+E)/2	GENERATION	TRANSMISSION	DISTRIBUTION	GENERATION	TRANSMISSION	DISTRIBUTION	GENERATION	TRANSMISSION	DISTRIBUTION
1.00	ACCOUNT 281:														
2.01															
2.02		0	0			0	0	0	0						
2.03															
2.04		0	0	0	0	0									
2.05		0	0	0	0	0									
2.06		0	0	0	0	0									
3	TOTAL ACCOUNT 281	0	0	0	0	0	0	0	0	0	0	0	0	0	0
4	ACCOUNT 281 - ARO-Related Deferrals	0	0	0	0	0	0	0	0	0	0	0	0	0	0
5	ACCOUNT 282:														
5.01		0	0			0	0	0	0						
5.02		0	0			0	0	0	0						
5.03		0	0			0	0	0	0						
5.04		0	0			0	0	0	0						
5.05		0	0			0	0	0	0						
5.06		0	0			0	0	0	0						
5.07		0	0			0	0	0	0						
5.08		0	0			0	0	0	0						
5.09		0	0			0	0	0	0						
5.10		0	0			0	0	0	0						
5.38		0	0			0	0	0	0						
5.39				0	0	0									
5.40				0	0	0									
5.41				0	0	0									
6	TOTAL ACOUNT 282	0	0	0	0	0	0	0	0	0	0	0	0	0	0
7	ACCOUNT 282 - ARO-Related Deferals	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8	ACCOUNT 283:														
9.01		0	0			0	0	0	0						
9.02		0	0			0	0	0	0						
9.03		0	0			0	0	0	0						
9.04		0	0			0	0	0	0						
9.05		0	0			0	0	0	0						
9.06		0	0			0	0	0	0						
9.07		0	0			0	0	0	0						
9.08		0	0			0	0	0	0						
9.94				0	0	0									
9.95				0	0	0									
9.96				0	0	0									
9.97				0	0	0									
9.98				0	0	0									
9.99				0	0	0									
10		0	0	0	0	0	0	0	0	0	0	0	0	0	0
11	DEFD STATE INCOME TAXES	0	0			0	0	0	0						
11.01				0	0	0									
12	TOTAL ACCOUNT 283	0	0	0	0	0	0	0	0	0	0	0	0	0	0
13	ACCOUNT 283 - ARO-Related Deferals	0	0	0	0	0	0	0	0	0	0	0	0	0	0
14	JURISDICTIONAL AMOUNTS FUNCTIONALIZED														
15	TOTAL COMPANY AMOUNTS FUNCTIONALIZED														
16	REFUNCTIONALIZED BASED ON JURISDICTIONAL PLANT														
17	NOTE: POST 1970 ACCUMULATED DEFERRED														
18	INV TAX CRED. (JDITC) IN A/C 255														
18.01		0	0			0	0	0	0						
18.02		0	0			0	0	0	0						
19															
20	TOTAL ACCOUNT 255	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Ohio Power Company
ACCUMULATED DEFERRED INCOME TAX IN ACCOUNT 190 - Actual Cycle Only
PERIOD ENDED DECEMBER 31, 2019

DEBIT (CREDIT)

	COLUMN A	COLUMN B	COLUMN C	COLUMN D	COLUMN E	COLUMN F	COLUMN G	COLUMN H	COLUMN I	COLUMN J	COLUMN K	COLUMN L	COLUMN M	COLUMN N	COLUMN O
		PER BOOKS		NON-APPLICABLE/NON-UTILITY		AVERAGE ELECTRIC UTILITY	FUNCTIONALIZATION AVERAGE			FUNCTIONALIZATION 12/31/2018			FUNCTIONALIZATION 12/31/2019		
	ACCUMULATED DEFERRED FIT ITEMS	BALANCE AS OF 12-31-2018	BALANCE AS OF 12-31-2019	BALANCE AS OF 12-31-2018	BALANCE AS OF 12-31-2019	(B+C+D+E)/2	GENERATION	TRANSMISSION	DISTRIBUTION	GENERATION	TRANSMISSION	DISTRIBUTION	GENERATION	TRANSMISSION	DISTRIBUTION
1	ACCOUNT 190:														
2.01		0	0			0	0	0	0						
2.02		0	0			0	0	0	0						
2.03		0	0			0	0	0	0						
2.04		0	0			0	0	0	0						
2.05		0	0			0	0	0	0						
2.06		0	0			0	0	0	0						
2.07		0	0			0	0	0	0						
2.08		0	0			0	0	0	0						
2.09		0	0			0	0	0	0						
2.10		0	0			0	0	0	0						
2.79		0	0			0	0	0	0						
2.80				0	0	0									
2.81				0	0	0									
2.82				0	0	0									
2.83				0	0	0									
2.84				0	0	0									
2.85				0	0	0									
2.86				0	0	0									
2.87				0	0	0									
2.88				0	0	0									
2.89				0	0	0									
2.90				0	0	0	0	0	0						
2.91		0	0			0	0	0	0						
3	TOTAL ACCOUNT 190	0	0	0	0	0	0	0	0	0	0	0	0	0	0
4	ACCOUNT 190 - ARO-Related Deferals	0	0	0	0	0	0	0	0	0	0	0	0	0	0

AEP East Companies
Cost of Service Formula Rate Using Actual/Projected FF1 Balances
Worksheet C Supporting Working Capital Rate Base Adjustments
Ohio Power Company

Materials & Supplies

Line Number	(A)	(B)	(C) Source	(D) Balance @ December 31, 2019	(E) Balance @ December 31, 2018	(F) Average Balance for 2019
1						
2		Transmission Materials & Supplies	FF1, p. 227, ln 8, Col. (c) & (b)	4,268,000	4,268,000	4,268,000
3		General Materials & Supplies	FF1, p. 227, ln 11, Col. (c) & (b)			-
4		Stores Expense (Undistributed) - Account 163	FF1, p. 227, ln 16, Col. (c) & (b)			-

Prepayment Balance Summary (Note 1)

5		Average of YE Balance	Excludable Balances	100% Transmission Related	Transmission Plant Related	Transmission Labor Related	Total Included in Ratebase (E)+(F)+(G)
6	Totals as of December 31, 2019	13,097,000	(180,426,172)	(219,014)	2,023,895	191,718,292	193,523,172
7	Totals as of December 31, 2018	12,489,999	(172,064,052)	(208,864)	1,930,094	182,832,822	184,554,052
8	**Average Balance**	12,793,500	(176,245,112)	(213,939)	1,976,995	187,275,557	189,038,612

Prepayments Account 165 - Balance @ 12/31/2019

9	Acc. No.	Description	2019 YE Balance	Excludable Balances	100% Transmission Related	Transmission Plant Related	Transmission Labor Related	Total Included in Ratebase (E)+(F)+(G)	Explanation
10	1650001	Prepaid Insurance	1,095,921	-		1,095,921		1,095,921	Plant Related Insurance Policies
11	1650003	Prepaid Rents	0	-				-	
12	1650004	Prepaid Interest	0	-				-	
13	1650005	Prepaid Employee Benefits	0	-			-	-	Health Savings
14	1650006	Other Prepayments	3,493,272	3,493,272				-	Distribution
15	1650009	Prepaid Carry Cost-Factored AR	389,584	389,584				-	AR Factoring - Retail Only
16	1650010	Prepaid Pension Benefits	162,709,802				162,709,802	162,709,802	Prepaid Pension Expense
17	165001219	Prepaid Taxes	123,493	123,493				-	Prepaid Taxes-Distribution
18	1650013	Gavin JMG ST Prepaid Exp - Aff	0	-			-	-	
19	1650014	FAS 158 Qual Contra Asset	(162,709,802)	(162,709,802)			-	-	FAS 158 Liability
20	1650016	FAS 112 ASSETS	0	-		-		-	
21	1650017	Prepayments - Coal	0	-			-	-	
22	1650019	Prepaid Pension Expense - CG&E	61,574	-	61,574		-	61,574	Prepaid Pension Expense
23	1650020	Prepaid Pension Expense - DP&L	(280,588)	-	(280,588)			(280,588)	Prepaid Pension Expense
24	1650021	Prepaid Insurance - EIS	927,974	-		927,974	-	927,974	Energy EIS Services
25	1650023	Prepaid Lease	73,037	73,037			-	-	Distribution Lease
26	1650035	PRW Without Med-D Benefits	29,008,490				29,008,490	29,008,490	Prepaid Pension Expense
27	1650030	Other Prepayments -Long Term	7,212,733	7,212,733			-	-	Smart Grid prepaid equipment
28	1650037	FAS158 Contra-PRW Exc Med-D	(29,008,490)	(29,008,490)					FAS 158 Liability
29									
30				-	-			-	
		Subtotal - Form 1, p 111.57.c	13,097,000	(180,426,172)	(219,014)	2,023,895	191,718,292	193,523,172	

Prepayments Account 165 - Balance @ 12/31/ 2018

31	Acc. No.	Description	2018 YE Balance	Excludable Balances	100% Transmission Related	Transmission Plant Related	Transmission Labor Related	Total Included in Ratebase (E)+(F)+(G)	Explanation
32	1650001	Prepaid Insurance	1,045,129	-		1,045,129		1,045,129	Plant Related Insurance Policies
33	1650003	Prepaid Rents	0	-				-	
34	1650004	Prepaid Interest	0	-				-	
35	1650005	Prepaid Employee Benefits	0	-			-	-	Health Savings
36	1650006	Other Prepayments	3,331,372	3,331,372				-	Distribution
37	1650009	Prepaid Carry Cost-Factored AR	371,528	371,528				-	AR Factoring - Retail Only
38	1650010	Prepaid Pension Benefits	155,168,773				155,168,773	155,168,773	Prepaid Pension Expense
39	165001218	Prepaid Taxes	117,770	117,770				-	Prepaid Taxes-Distribution
40	1650013	Gavin JMG ST Prepaid Exp - Aff	0	-			-	-	
41	1650014	FAS 158 Qual Contra Asset	(155,168,773)	(155,168,773)			-	-	FAS 158 Liability
42	1650016	FAS 112 ASSETS	0	-		-		-	
43	1650017	Prepayments - Coal	0	-			-	-	
44	1650019	Prepaid Pension Expense - CG&E	58,720	-	58,720		-	58,720	Prepaid Pension Expense
45	1650020	Prepaid Pension Expense - DP&L	(267,584)	-	(267,584)			(267,584)	Prepaid Pension Expense
46	1650021	Prepaid Insurance - EIS	884,965	-		884,965	-	884,965	Energy EIS Services
47	1650023	Prepaid Lease	69,652	69,652			-	-	Distribution Lease
48	1650035	PRW Without Med-D Benefits	27,664,048				27,664,048	27,664,048	Prepaid Pension Expense
49	1650030	Other Prepayments -Long Term	6,878,448	6,878,448			-	-	Smart Grid prepaid equipment
50	1650037	FAS158 Contra-PRW Exc Med-D	(27,664,048)	(27,664,048)					FAS 158 Liability
51									
52				-	-			-	
		Subtotal - Form 1, p 111.57.d	12,489,999	(172,064,052)	(208,864)	1,930,094	182,832,822	184,554,052	

Note 1: Prepayment Balance will not include: (i) federal and state income tax payments made to offset additional tax liabilities resulting (or expected to result) from prior federal or state audits or from the filing of one or more amended income tax returns; (ii) outstanding income tax refunds due to the company resulting (or expected to result) from prior federal or state audits or from the filing of one or more amended income tax returns; or (iii) prepayments of federal or state income taxes which are attributable to income earned during periods prior to January 1 of the year depicted in the Balance Sheet (as described in USofA Account 236).

AEP East Companies
Cost of Service Formula Rate Using Actual/Projected FF1 Balances
Worksheet D Supporting IPP Credits
Ohio Power Company

Line Number	(A) Description	(B) 2019
1	Net Funds from IPP Customers 12/31/2018 (2019 FORM 1, P269)	0
2	Interest Accrual (Company Records - Note 1)	0
3	Revenue Credits to Generators (Company Records - Note 1)	
4	Other Adjustments	
5	Accounting Adjustment (Company Records - Note 1)	
6		-
7	Net Funds from IPP Customers 12/31/2019 (2019 FORM 1, P269)	-
8	Average Balance for Year as Indicated in Column B ((ln 1 + ln 7)/2)	-

Note 1 On this worksheet Company Records refers to Ohio Power Company's general ledger.

AEP East Companies
Cost of Service Formula Rate Using Actual/Projected FF1 Balances
Worksheet E Supporting Revenue Credits
Ohio Power Company

Line Number	Description	Total Company	Non-Transmission	Transmission
1	**Account 450, Forfeited Discounts (FF1 p.300.16.(b); Company Records - Note 1)**	3,500,000	3,500,000	
2	**Account 451,Miscellaneous Service Revenues (FF1 p.300.17.(b); Company Records - Note 1)**	7,500,000	7,381,000	119,000
3	**Account 454, Rent from Electric Property (FF1 p.300.19.(b); Company Records - Note 1)**	40,578,000	29,865,000	10,713,000
4	**Account 4560015, Associated Business Development - (Company Records - Notes 1, 2)**	4,105,000	3,771,000	334,000
5	**Account 456 - Other Electric Revenues - (Company Records - Notes 1,2)**	71,233,000	71,233,000	
5a	**Account 457.1, Regional Control Service Revenues (FF1 p.300.23.(b); Company Records - Note 1)**		-	
5b	**Account 457.2, Miscellaneous Revenues (FF1p.300.24.(b); Company Records - Note 1)**		-	
6	**Subtotal - Other Operating Revenues (Company Total equals (FF1 p. 300.26.(b))**	126,916,000	115,750,000	11,166,000
7	**Accounts 4470004 & 5, Revenues from Grandfathered Transmission Contracts - (Company Records - Note 1)**		-	
8	**Total Other Operating Revenues To Reduce Revenue Requirement**	126,916,000	115,750,000	11,166,000

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

Note 2 The total of line 4 and line 5 will equal total Account 456 as listed on FF1 p.300.21-22.(b)

9	**Facility Credits under PJM OATT Section 30.9**			4,028,356

AEP East Companies
Cost of Service Formula Rate Using Actual/Projected FF1 Balances
Worksheet F Supporting Allocation of Specific O&M or A&G Expenses
Ohio Power Company

	(A)	(B)	(C)	(D)	(E)	(F)
Line Number	**Item No.**	**Description**	**2019 Expense**	**100% Non-Transmission**	**100% Transmission Specific**	**Explanation**
		Regulatory O&M Deferrals & Amortizations				
1	5660005					
2						
3						
4		**Total**	0			
		Detail of Account 561 Per FERC Form 1				
5						
6	FF1 p 321.85.b	561.1 - Load Dispatch - Reliability	61,000			
7	FF1 p 321.86.b	561.2 - Load Dispatch - Monitor & Operate Trans System	4,759,000			
8	FF1 p 321.87.b	561.3 - Load Dispatch - Trans Service & Scheduling				
9	FF1 p 321.88.b	561.4 - Scheduling, System Control & Dispatch	107,000			
10	FF1 p 321.89.b	561.5 - Reliability, Planning and Standards Development	1,435,000			
11	FF1 p 321.90.b	561.6 - Transmission Service Studies				
12	FF1 p 321.91.b	561.7 - Generation Interconnection Studies				
13	FF1 p 321.92.b	561.8 - Reliability, Planning and Standards Development Services	1,000			
14		**Total of Account 561**	6,363,000			
		Account 928				
15	9280000	Regulatory Commission Exp	942,762	942,762	-	
16	9280005	Regulatory Commission Exp - FERC	81,238	-	81,238	
17				-	-	
18				-		
19						
20		**Total (FERC Form 1 p.323.189.b)**	1,024,000	942,762	81,238	
		Account 930.1				
21	9301000	General Advertising Expenses	229,000	229,000	-	
22				-	-	
23				-	-	
24				-	-	
25				-	-	
26				-	-	
27				-	-	
28				-	-	
29						
30						
31				-		
32				-	-	
33				-	-	
34				-	-	
35				-	-	
36				-	-	
37		**Total (FERC Form 1 p.323.191.b)**	229,000	229,000	-	
		Account 930.2				
38	9302000	Misc General Expenses	(2,716,000)	(2,716,000)		
39	9302003	Corporate & Fiscal Expenses	-	-		
40	9302004	Research, Develop&Demonstr Exp	-	-		
41	9302006	Assoc Business Development Materials Sold	-	-	-	
42	9302007	Assoc Business Development Exp	1,953,000	1,465,000	488,000	
43		**Total (FERC Form 1 p.323.192.b)**	(763,000)	(1,251,000)	488,000	

AEP East Companies
Cost of Service Formula Rate Using Actual/Projected FF1 Balances
Worksheet G Supporting - Development of Composite State Income Tax Rate
Ohio Power Company

West Virginia Corporate Income Tax	6.5000%	
Apportionment Factor - Note 2	0.4267%	
Effective State Tax Rate		0.03%
Illinois Corporation Income Tax	9.5000%	
Apportionment Factor - Note 2	0.3238%	
Effective State Tax Rate		0.03%
Michigan Business Income Tax	6.0000%	
Apportionment Factor - Note 2	0.0148%	
Effective State Tax Rate		0.00%
Kentucky Business Income Tax	5.0000%	
Apportionment Factor - Note 2	0.0430%	
Effective State Tax Rate		0.00%
Ohio Municipal Net Income Tax	1.0169%	
Apportionment Factor - Note 2	98.8100%	
Effective State Tax Rate		1.00%
Ohio Franchise Tax Rate	0.0000%	
Phase-out Factor Note 1	0.0000%	
Apportionment Factor - Note 2	0.0000%	
Effective State Tax Rate		0.00%
Total Effective State Income Tax Rate		1.0664%

Note 1 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 Actual/Projected FF1 Balances
Worksheet H Supporting Taxes Other than Income
Ohio Power Company

Line No.	(A) Account	(B) Total Company NOTE 1	(C) Property	(D) Labor	(E) Other	(F) Non-Allocable
1	Revenue Taxes					
2	Gross Receipts Tax	141,116,000				141,116,000
3	Real Estate and Personal Property Taxes					
4	Real and Personal Property - Ohio	265,919,000	265,919,000			
5	Real and Personal Property - Other Jurisdictions	998,000	998,000			
6	Real and Personal Property - Tennessee	-	-			
7	Real and Personal Property - Other Jurisdictions	31,000	31,000			
8	Payroll Taxes					
9	Federal Insurance Contribution (FICA)	6,269,000		6,269,000		
10	Federal Unemployment Tax	38,000		38,000		
11	State Unemployment Insurance	120,000		120,000		
12	Production Taxes					
13	State Severance Taxes	-				-
14	Miscellaneous Taxes					
15	State Business & Occupation Tax	-				-
16	State Public Service Commission Fees	3,701,000			3,701,000	
17	State Franchise Taxes	-			-	
18	State Lic/Registration Fee	-			-	
19	Misc. State and Local Tax	-			-	
20	Sales & Use	-				-
21	Federal Excise Tax	-				-
22	Michigan Single Business Tax	-				-
23						
24	Total Taxes by Allocable Basis	418,192,000	266,948,000	6,427,000	3,701,000	141,116,000
	(Total Company Amount Ties to FFI p.114, Ln 14,(c))					

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

Functional Property Tax Allocation

Line		Production	Transmission	Distribution	General	Total
25	Functionalized Net Plant (TCOS, Lns 41 thru 46)	-	1,684,117,385	3,540,428,846	297,889,769	5,522,436,000
	OHIO JURISDICTION					
26	Percentage of Plant in OHIO JURISDICTION	0.00%	94.77%	100.00%	98.93%	
27	Net Plant in OHIO JURISDICTION (Ln 25 * Ln 26)	-	1,596,038,045	3,540,428,846	294,702,349	5,431,169,240
28	Less: Net Value of Exempted Generation Plant	-				
29	Taxable Property Basis (Ln 27 - Ln 28)	-	1,596,038,045	3,540,428,846	294,702,349	5,431,169,240
30	Relative Valuation Factor	24%	85%	85%	24%	
31	Weighted Net Plant (Ln 29 * Ln 30)	-	1,356,632,339	3,009,364,519	70,728,564	
32	General Plant Allocator (Ln 31 / (Total - General Plant))	0.00%	31.07%	68.93%	-100.00%	
33	Functionalized General Plant (Ln 32 * General Plant)	-	21,977,262	48,751,302	(70,728,564)	-
34	Weighted OHIO JURISDICTION Plant (Ln 31 + 33)	-	1,378,609,601	3,058,115,821	(0)	4,436,725,422
35	Functional Percentage (Ln 34/Total Ln 34)	0.00%	31.07%	68.93%		
	WEST VA JURISDICTION					
36	Net Plant in WEST VA JURISDICTION (Ln 25 - Ln 27)	-	88,079,339	-	3,187,421	91,266,760
37	Less: Net Value of Exempted Generation Plant	-				
38	Taxable Property Basis (Ln 36 - Ln 37)	-	88,079,339	-	3,187,421	91,266,760
39	Relative Valuation Factor	100%	100%	100%	100%	
40	Weighted Net Plant (Ln 38 * Ln 39)	-	88,079,339	-	3,187,421	
41	General Plant Allocator (Ln 40 / (Total - General Plant))	0.00%	100.00%	0.00%	-100.00%	
42	Functionalized General Plant (Ln 41 * General Plant)	-	3,187,421	-	(3,187,421)	-
43	Weighted WEST VA JURISDICTION Plant (Ln 40 + 42)	-	91,266,760	-	(0)	91,266,760
44	Functional Percentage (Ln 43/Total Ln 43)	0.00%	100.00%	0.00%		

AEP East Companies
Cost of Service Formula Rate Using Actual/Projected FF1 Balances
Worksheet H-1 Form 1 Source Reference of Company Amounts on WS H
Ohio 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	141,116,000		
			141,116,000	

Line No.	(A) Real Estate and Personal Propety Tax Detail Annual Tax Expenses by Type (Note 1)	(B) Tax Year	(C) Total Company	(D) FERC FORM 1 Tie-Back	(E) FERC FORM 1 Reference	(F) Tax Year Factor (Note 2)	(G) Transmission Function (Note 2)
3	Real Estate and Personal Property Taxes Total (Ln 4 + Ln 5 + Ln 6 + Ln 7)		**266,948,000**				**82,946,493**
4	Real and Personal Property - Ohio		265,919,000				82,628,166
				265,919,000		31.07%	82,628,166
							-
							-
							-
							-
5	Real and Personal Property - W VA		998,000				318,326
				998,000		31.90%	318,326
							-
							-
							-
							-
							-
							-
							-
							-
6	Real and Personal Property - Tennessee		-				-
							-
							-
							-
							-
							-
			31,000				-
7	Real and Personal Property - Other Jurisdictions			31,000			-
							-
							-

Line No.	(A) Annual Tax Expenses by Type (Note 1)	(B) Total Company	(C) FERC FORM 1 Tie-Back	(D) FERC FORM 1 Reference
8	Payroll Taxes			
9	Federal Insurance Contribution (FICA)	6,269,000		
			6,269,000	
10	Federal Unemployment Tax	38,000		
			38,000	
11	State Unemployment Insurance	120,000		
			120,000	
12	Production Taxes	-		
13	State Severance Taxes			
14	Miscellaneous Taxes			
15	State Business & Occupation Tax	-		
16	State Public Service Commission Fees	3,701,000		
			3,701,000	
17	State Franchise Taxes	-		
18	State Lic/Registration Fee	-		
19	Misc. State and Local Tax	-		
20	Sales & Use	-		
21	Federal Excise Tax	-		
22	Michigan Single Business Tax	-		
23	Total Taxes by Allocable Basis (Total Company Amount Ties to FFI p.114, Ln 14,(c))	418,192,000	418,192,000	

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.(c) of the Ferc Form 1.

Note 2: The transmission functional amounts for any Real Estate and Property taxes listed on pages 263 of the FERC Form 1 will be allocated using the transmission functional allocator calculated for each state in Worksheet H of the applicable year that the taxes were assesed. Real and Personal Property - Other Jurisdictions will be allocated using the Gross Plant Allocator from the applicable year.

AEP East Companies
Cost of Service Formula Rate Using 2019 FF1 Balances
Worksheet I RESERVED FOR FUTURE USE
Ohio Power Company

AEP East Companies
Cost of Service Formula Rate Using 2019 FF1 Balances
Worksheet J Supporting Calculation of PROJECTED PJM RTEP Project Revenue Requirement Billed to Benefiting Zones
Ohio Power Company

Page 1 of 22

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 (TCOS, ln 156)			10.35%
Project ROE Incentive Adder			
ROE with additional basis point incentive			10.35%

Determine R (cost of long term debt, cost of preferred stock and equity percentage is from the TCOS, lns 154 through156)

	%	Cost	Weighted cost
Long Term Debt	45.03%	5.27%	2.375%
Preferred Stock	0.00%	0.00%	0.000%
Common Stock	54.97%	10.35%	5.689%
		R =	8.065%

SUMMARY OF PROJECTED ANNUAL RTEP REVENUE REQUIREMENTS

	Rev Require	W Incentives	Incentive Amounts
2019	10,202,114	10,202,114	$ -

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

Rate Base (TCOS, ln 68)	1,355,197,381
R (from A. above)	8.065%
Return (Rate Base x R)	109,290,462

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

Return (from B. above)	109,290,462
Effective Tax Rate (TCOS, ln 114)	19.72%
Income Tax Calculation (Return x CIT)	21,546,935
ITC Adjustment	(408)
Excess Deferred Income Tax	(6,679,383)
Tax Affect of Permanent Differences	2,322,954
Income Taxes	17,190,097

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 (TCOS, ln 1)
Lease Payments (TCOS, Ln 95)
Return (TCOS, ln 126)
Income Taxes (TCOS, ln 125)
Annual Revenue Requirement, Less Lease Payments, Return and Taxes

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

Annual Revenue Requirement, Less Lease Payments, Return and Taxes
Return (from I.B. above)
Income Taxes (from I.C. above)
Annual Revenue Requirement, with Basis Point ROE increase
Depreciation (TCOS, ln 100)
Annual Rev. Req, w/ Basis Point ROE increase, less Depreciation

C. Determine FCR with hypothetical basis point ROE increase.

Net Transmission Plant (TCOS, ln 42)
Annual Revenue Requirement, with Basis Point ROE increase
FCR with Basis Point increase in ROE

Annual Rev. Req, w / Basis Point ROE increase, less Dep.
FCR with Basis Point ROE increase, less Depreciation
FCR less Depreciation (TCOS, ln 10)
Incremental FCR with Basis Point ROE increase, less Depreciation

III. Calculation of Composite Depreciation Rate

Average Transmission Plant Balance for 2019 (TCOS, ln 21)
Annual Depreciation and Amortization Expense (TCOS, ln 100)
Composite Depreciation Rate
Depreciable Life for Composite Depreciation Rate
Round to nearest whole year

OPCo 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.

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

	766,759
	766,759
	-

Details		
Investment	5,559,037	Current Year
Service Year (yyyy)	2009	ROE increase accepted by FERC (Basis Points)
Service Month (1-12)	3	FCR w/o incentives, less depreciation
Useful life	44	FCR w/incentives approved for these facilities, less dep.
CIAC (Yes or No)	No	Annual Depreciation Expense

CUMULATIVE HISTORY OF PROJECTED ANNUAL REVENUE REQUIREMENTS:

Investment Year	Beginning Balance	Depreciation Expense	Ending Balance		RTEP Projected Rev. Req't.From Prior Year Template with Incentives **		
2009	5,559,037	94,756	5,464,281		$ 894,796		
2010	5,464,281	126,342	5,337,939		$ 1,094,271		
2011	5,337,939	126,342	5,211,597		$ 1,210,680		
2012	5,211,597	126,342	5,085,255		$ 1,057,666		
2013	5,085,255	126,342	4,958,914		$ 1,051,933		
2014	4,958,914	126,342	4,832,572		$ 1,050,369		
2015	4,832,572	126,342	4,706,230		$ 1,028,335		
2016	4,706,230	126,342	4,579,888		$ 989,594		
2017	4,579,888	126,342	4,453,547		$ 996,311		
2018	4,453,547	126,342	4,327,205		$ 790,538		
2019	4,327,205	126,342	4,200,863				
2020	4,200,863	126,342	4,074,521				
2021	4,074,521	126,342	3,948,180				
2022	3,948,180	126,342	3,821,838				
2023	3,821,838	126,342	3,695,496				
2024	3,695,496	126,342	3,569,154				
2025	3,569,154	126,342	3,442,813				
2026	3,442,813	126,342	3,316,471				
2027	3,316,471	126,342	3,190,129				
2028	3,190,129	126,342	3,063,787				
2029	3,063,787	126,342	2,937,446				
2030	2,937,446	126,342	2,811,104				
2031	2,811,104	126,342	2,684,762				
2032	2,684,762	126,342	2,558,420				
2033	2,558,420	126,342	2,432,079				
2034	2,432,079	126,342	2,305,737				
2035	2,305,737	126,342	2,179,395				
2036	2,179,395	126,342	2,053,053				
2037	2,053,053	126,342	1,926,712				
2038	1,926,712	126,342	1,800,370				
2039	1,800,370	126,342	1,674,028				
2040	1,674,028	126,342	1,547,686				
2041	1,547,686	126,342	1,421,345				
2042	1,421,345	126,342	1,295,003				
2043	1,295,003	126,342	1,168,661				
2044	1,168,661	126,342	1,042,319				
2045	1,042,319	126,342	915,978				
2046	915,978	126,342	789,636				
2047	789,636	126,342	663,294				
2048	663,294	126,342	536,952				
2049	536,952	126,342	410,611				
2050	410,611	126,342	284,269				
2051	284,269	126,342	157,927				
2052	157,927	126,342	31,585				
2053	31,585	31,585	-				
2054	-	-	-				
2055	-	-	-				
2056	-	-	-				
2057	-	-	-				
2058	-	-	-				
2059	-	-	-				
2060	-	-	-				
2061	-	-	-				
2062	-	-	-				
2063	-	-	-				
2064	-	-	-				
2065	-	-	-				
2066	-	-	-				
2067	-	-	-				
2068	-	-	-				
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.

OPCo 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.

	982,301
	982,301
	-

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

Details		
Investment	6,529,259	Current Year
Service Year (yyyy)	2012	ROE increase accepted by FERC (Basis Points)
Service Month (1-12)	11	FCR w/o incentives, less depreciation
Useful life	44	FCR w/incentives approved for these facilities, less dep.
CIAC (Yes or No)	No	Annual Depreciation Expense

CUMULATIVE HISTORY OF PROJECTED ANNUAL REVENUE REQUIREMENTS:

Investment Year	Beginning Balance	Depreciation Expense	Ending Balance		RTEP Projected Rev. Req't.From Prior Year Template with Incentives **		
2012	6,529,259	12,366	6,516,893		$ 832,082		
2013	6,516,893	148,392	6,368,501		$ 1,210,587		
2014	6,368,501	148,392	6,220,108		$ 1,247,628		
2015	6,220,108	148,392	6,071,716		$ 1,279,512		
2016	6,071,716	148,392	5,923,324		$ 1,233,365		
2017	5,923,324	148,392	5,774,932		$ 1,245,646		
2018	5,774,932	148,392	5,626,539		$ 1,010,825		
2019	5,626,539	148,392	5,478,147				
2020	5,478,147	148,392	5,329,755				
2021	5,329,755	148,392	5,181,363				
2022	5,181,363	148,392	5,032,970				
2023	5,032,970	148,392	4,884,578				
2024	4,884,578	148,392	4,736,186				
2025	4,736,186	148,392	4,587,794				
2026	4,587,794	148,392	4,439,401				
2027	4,439,401	148,392	4,291,009				
2028	4,291,009	148,392	4,142,617				
2029	4,142,617	148,392	3,994,225				
2030	3,994,225	148,392	3,845,832				
2031	3,845,832	148,392	3,697,440				
2032	3,697,440	148,392	3,549,048				
2033	3,549,048	148,392	3,400,656				
2034	3,400,656	148,392	3,252,263				
2035	3,252,263	148,392	3,103,871				
2036	3,103,871	148,392	2,955,479				
2037	2,955,479	148,392	2,807,087				
2038	2,807,087	148,392	2,658,694				
2039	2,658,694	148,392	2,510,302				
2040	2,510,302	148,392	2,361,910				
2041	2,361,910	148,392	2,213,518				
2042	2,213,518	148,392	2,065,125				
2043	2,065,125	148,392	1,916,733				
2044	1,916,733	148,392	1,768,341				
2045	1,768,341	148,392	1,619,949				
2046	1,619,949	148,392	1,471,556				
2047	1,471,556	148,392	1,323,164				
2048	1,323,164	148,392	1,174,772				
2049	1,174,772	148,392	1,026,380				
2050	1,026,380	148,392	877,987				
2051	877,987	148,392	729,595				
2052	729,595	148,392	581,203				
2053	581,203	148,392	432,811				
2054	432,811	148,392	284,418				
2055	284,418	148,392	136,026				
2056	136,026	136,026	-				
2057	-	-	-				
2058	-	-	-				
2059	-	-	-				
2060	-	-	-				
2061	-	-	-				
2062	-	-	-				
2063	-	-	-				
2064	-	-	-				
2065	-	-	-				
2066	-	-	-				
2067	-	-	-				
2068	-	-	-				
2069	-	-	-				
2070	-	-	-				
2071	-	-	-				
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.

OPCo 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.

Project Description: **RTEP ID: b0570 (Reconductor EAST LIMA-STERLING 138 KV L**

142,952
142,952
-

Details		
Investment	937,776	Current Year
Service Year (yyyy)	2013	ROE increase accepted by FERC (Basis Points)
Service Month (1-12)	6	FCR w/o incentives, less depreciation
Useful life	44	FCR w/incentives approved for these facilities, less dep.
CIAC (Yes or No)	No	Annual Depreciation Expense

CUMULATIVE HISTORY OF PROJECTED ANNUAL REVENUE REQUIREMENTS:

Investment Year	Beginning Balance	Depreciation Expense	Ending Balance		RTEP Projected Rev. Req't.From Prior Year Template with Incentives **		
2013	937,776	10,657	927,119		$ 219,263		
2014	927,119	21,313	905,806		$ 203,042		
2015	905,806	21,313	884,493		$ 228,159		
2016	884,493	21,313	863,180		$ 81,330		
2017	863,180	21,313	841,867		$ 222,274		
2018	841,867	21,313	820,554		$ 147,062		
2019	820,554	21,313	799,241				
2020	799,241	21,313	777,928				
2021	777,928	21,313	756,615				
2022	756,615	21,313	735,302				
2023	735,302	21,313	713,989				
2024	713,989	21,313	692,675				
2025	692,675	21,313	671,362				
2026	671,362	21,313	650,049				
2027	650,049	21,313	628,736				
2028	628,736	21,313	607,423				
2029	607,423	21,313	586,110				
2030	586,110	21,313	564,797				
2031	564,797	21,313	543,484				
2032	543,484	21,313	522,171				
2033	522,171	21,313	500,858				
2034	500,858	21,313	479,545				
2035	479,545	21,313	458,231				
2036	458,231	21,313	436,918				
2037	436,918	21,313	415,605				
2038	415,605	21,313	394,292				
2039	394,292	21,313	372,979				
2040	372,979	21,313	351,666				
2041	351,666	21,313	330,353				
2042	330,353	21,313	309,040				
2043	309,040	21,313	287,727				
2044	287,727	21,313	266,414				
2045	266,414	21,313	245,101				
2046	245,101	21,313	223,787				
2047	223,787	21,313	202,474				
2048	202,474	21,313	181,161				
2049	181,161	21,313	159,848				
2050	159,848	21,313	138,535				
2051	138,535	21,313	117,222				
2052	117,222	21,313	95,909				
2053	95,909	21,313	74,596				
2054	74,596	21,313	53,283				
2055	53,283	21,313	31,970				
2056	31,970	21,313	10,657				
2057	10,657	10,657	-				
2058	-	-	-				
2059	-	-	-				
2060	-	-	-				
2061	-	-	-				
2062	-	-	-				
2063	-	-	-				
2064	-	-	-				
2065	-	-	-				
2066	-	-	-				
2067	-	-	-				
2068	-	-	-				
2069	-	-	-				
2070	-	-	-				
2071	-	-	-				
2072	-	-	-				
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.

OPCo 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.

	877,873
	877,873
	-

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

Details		
Investment	5,705,686	Current Year
Service Year (yyyy)	2013	ROE increase accepted by FERC (Basis Points)
Service Month (1-12)	11	FCR w/o incentives, less depreciation
Useful life	44	FCR w/incentives approved for these facilities, less dep.
CIAC (Yes or No)	No	Annual Depreciation Expense

CUMULATIVE HISTORY OF PROJECTED ANNUAL REVENUE REQUIREMENTS:

Investment Year	Beginning Balance	Depreciation Expense	Ending Balance		RTEP Projected Rev. Req't.From Prior Year Template with Incentives **		
2013	5,705,686	10,806	5,694,880		$ 528,784		
2014	5,694,880	129,675	5,565,205		$ 1,017,894		
2015	5,565,205	129,675	5,435,530		$ 953,651		
2016	5,435,530	129,675	5,305,856		$ 919,468		
2017	5,305,856	129,675	5,176,181		$ 929,340		
2018	5,176,181	129,675	5,046,506		$ 902,942		
2019	5,046,506	129,675	4,916,832				
2020	4,916,832	129,675	4,787,157				
2021	4,787,157	129,675	4,657,482				
2022	4,657,482	129,675	4,527,808				
2023	4,527,808	129,675	4,398,133				
2024	4,398,133	129,675	4,268,458				
2025	4,268,458	129,675	4,138,784				
2026	4,138,784	129,675	4,009,109				
2027	4,009,109	129,675	3,879,434				
2028	3,879,434	129,675	3,749,760				
2029	3,749,760	129,675	3,620,085				
2030	3,620,085	129,675	3,490,410				
2031	3,490,410	129,675	3,360,736				
2032	3,360,736	129,675	3,231,061				
2033	3,231,061	129,675	3,101,386				
2034	3,101,386	129,675	2,971,711				
2035	2,971,711	129,675	2,842,037				
2036	2,842,037	129,675	2,712,362				
2037	2,712,362	129,675	2,582,687				
2038	2,582,687	129,675	2,453,013				
2039	2,453,013	129,675	2,323,338				
2040	2,323,338	129,675	2,193,663				
2041	2,193,663	129,675	2,063,989				
2042	2,063,989	129,675	1,934,314				
2043	1,934,314	129,675	1,804,639				
2044	1,804,639	129,675	1,674,965				
2045	1,674,965	129,675	1,545,290				
2046	1,545,290	129,675	1,415,615				
2047	1,415,615	129,675	1,285,941				
2048	1,285,941	129,675	1,156,266				
2049	1,156,266	129,675	1,026,591				
2050	1,026,591	129,675	896,917				
2051	896,917	129,675	767,242				
2052	767,242	129,675	637,567				
2053	637,567	129,675	507,893				
2054	507,893	129,675	378,218				
2055	378,218	129,675	248,543				
2056	248,543	129,675	118,868				
2057	118,868	118,868	-				
2058	-	-	-				
2059	-	-	-				
2060	-	-	-				
2061	-	-	-				
2062	-	-	-				
2063	-	-	-				
2064	-	-	-				
2065	-	-	-				
2066	-	-	-				
2067	-	-	-				
2068	-	-	-				
2069	-	-	-				
2070	-	-	-				
2071	-	-	-				
2072	-	-	-				
Project Totals							

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

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.

OPCo 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.

321,999
321,999
-

Project Description: **RTEP ID: b1034.6 (138kV circuit breakers at South Canton Stat**

Details		
Investment	2,088,951	Current Year
Service Year (yyyy)	2013	ROE increase accepted by FERC (Basis Points)
Service Month (1-12)	12	FCR w/o incentives, less depreciation
Useful life	44	FCR w/incentives approved for these facilities, less dep.
CIAC (Yes or No)	No	Annual Depreciation Expense

CUMULATIVE HISTORY OF PROJECTED ANNUAL REVENUE REQUIREMENTS:

Investment Year	Beginning Balance	Depreciation Expense	Ending Balance		RTEP Projected Rev. Req't.From Prior Year Template with Incentives **		
2013	2,088,951	-	2,088,951		$ 424,916		
2014	2,088,951	47,476	2,041,475		$ 372,954		
2015	2,041,475	47,476	1,993,999		$ 375,622		
2016	1,993,999	47,476	1,946,523		$ 363,235		
2017	1,946,523	47,476	1,899,046		$ 367,158		
2018	1,899,046	47,476	1,851,570		$ 331,181		
2019	1,851,570	47,476	1,804,094				
2020	1,804,094	47,476	1,756,618				
2021	1,756,618	47,476	1,709,142				
2022	1,709,142	47,476	1,661,666				
2023	1,661,666	47,476	1,614,189				
2024	1,614,189	47,476	1,566,713				
2025	1,566,713	47,476	1,519,237				
2026	1,519,237	47,476	1,471,761				
2027	1,471,761	47,476	1,424,285				
2028	1,424,285	47,476	1,376,809				
2029	1,376,809	47,476	1,329,332				
2030	1,329,332	47,476	1,281,856				
2031	1,281,856	47,476	1,234,380				
2032	1,234,380	47,476	1,186,904				
2033	1,186,904	47,476	1,139,428				
2034	1,139,428	47,476	1,091,952				
2035	1,091,952	47,476	1,044,476				
2036	1,044,476	47,476	996,999				
2037	996,999	47,476	949,523				
2038	949,523	47,476	902,047				
2039	902,047	47,476	854,571				
2040	854,571	47,476	807,095				
2041	807,095	47,476	759,619				
2042	759,619	47,476	712,142				
2043	712,142	47,476	664,666				
2044	664,666	47,476	617,190				
2045	617,190	47,476	569,714				
2046	569,714	47,476	522,238				
2047	522,238	47,476	474,762				
2048	474,762	47,476	427,285				
2049	427,285	47,476	379,809				
2050	379,809	47,476	332,333				
2051	332,333	47,476	284,857				
2052	284,857	47,476	237,381				
2053	237,381	47,476	189,905				
2054	189,905	47,476	142,428				
2055	142,428	47,476	94,952				
2056	94,952	47,476	47,476				
2057	47,476	47,476	-				
2058	-	-	-				
2059	-	-	-				
2060	-	-	-				
2061	-	-	-				
2062	-	-	-				
2063	-	-	-				
2064	-	-	-				
2065	-	-	-				
2066	-	-	-				
2067	-	-	-				
2068	-	-	-				
2069	-	-	-				
2070	-	-	-				
2071	-	-	-				
2072	-	-	-				
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.

OPCo 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.

	25,082
	25,082
	-

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

Details		
Investment	154,181	Current Year
Service Year (yyyy)	2016	ROE increase accepted by FERC (Basis Points)
Service Month (1-12)	6	FCR w/o incentives, less depreciation
Useful life	44	FCR w/incentives approved for these facilities, less dep.
CIAC (Yes or No)	No	Annual Depreciation Expense

CUMULATIVE HISTORY OF PROJECTED ANNUAL REVENUE REQUIREMENTS:

Investment Year	Beginning Balance	Depreciation Expense	Ending Balance		RTEP Projected Rev. Req't.From Prior Year Template with Incentives **		
2016	154,181	1,752	152,429		$ 42,109		
2017	152,429	3,504	148,925		$ 41,186		
2018	148,925	3,504	145,421		$ (7,120)		
2019	145,421	3,504	141,917				
2020	141,917	3,504	138,412				
2021	138,412	3,504	134,908				
2022	134,908	3,504	131,404				
2023	131,404	3,504	127,900				
2024	127,900	3,504	124,396				
2025	124,396	3,504	120,892				
2026	120,892	3,504	117,388				
2027	117,388	3,504	113,884				
2028	113,884	3,504	110,380				
2029	110,380	3,504	106,875				
2030	106,875	3,504	103,371				
2031	103,371	3,504	99,867				
2032	99,867	3,504	96,363				
2033	96,363	3,504	92,859				
2034	92,859	3,504	89,355				
2035	89,355	3,504	85,851				
2036	85,851	3,504	82,347				
2037	82,347	3,504	78,843				
2038	78,843	3,504	75,338				
2039	75,338	3,504	71,834				
2040	71,834	3,504	68,330				
2041	68,330	3,504	64,826				
2042	64,826	3,504	61,322				
2043	61,322	3,504	57,818				
2044	57,818	3,504	54,314				
2045	54,314	3,504	50,810				
2046	50,810	3,504	47,306				
2047	47,306	3,504	43,801				
2048	43,801	3,504	40,297				
2049	40,297	3,504	36,793				
2050	36,793	3,504	33,289				
2051	33,289	3,504	29,785				
2052	29,785	3,504	26,281				
2053	26,281	3,504	22,777				
2054	22,777	3,504	19,273				
2055	19,273	3,504	15,769				
2056	15,769	3,504	12,264				
2057	12,264	3,504	8,760				
2058	8,760	3,504	5,256				
2059	5,256	3,504	1,752				
2060	-	-	-				
2061	-	-	-				
2062	-	-	-				
2063	-	-	-				
2064	-	-	-				
2065	-	-	-				
2066	-	-	-				
2067	-	-	-				
2068	-	-	-				
2069	-	-	-				
2070	-	-	-				
2071	-	-	-				
2072	-	-	-				
2073	-	-	-				
2074	-	-	-				
2075	-	-	-				
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.

OPCo 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. — **682,446**

682,446

Project Description: **RTEP ID: b2021 (Add 345/138 kV Transformers at Sporn, Kanawha River, and Muskingum River stations)** — **-**

Details		
Investment	4,443,730	Current Year
Service Year (yyyy)	2013	ROE increase accepted by FERC (Basis Points)
Service Month (1-12)	10	FCR w/o incentives, less depreciation
Useful life	44	FCR w/incentives approved for these facilities, less dep.
CIAC (Yes or No)	No	Annual Depreciation Expense

CUMULATIVE HISTORY OF PROJECTED ANNUAL REVENUE REQUIREMENTS:

Investment Year	Beginning Balance	Depreciation Expense	Ending Balance		RTEP Projected Rev. Req't.From Prior Year Template with Incentives **		
2013	4,443,730	16,832	4,426,898		$ 0		
2014	4,426,898	100,994	4,325,904		$ 7,389,592		
2015	4,325,904	100,994	4,224,910		$ 583,939		
2016	4,224,910	100,994	4,123,916		$ 662,503		
2017	4,123,916	100,994	4,022,922		$ 750,034		
2018	4,022,922	100,994	3,921,928		$ 633,061		
2019	3,921,928	100,994	3,820,935				
2020	3,820,935	100,994	3,719,941				
2021	3,719,941	100,994	3,618,947				
2022	3,618,947	100,994	3,517,953				
2023	3,517,953	100,994	3,416,959				
2024	3,416,959	100,994	3,315,965				
2025	3,315,965	100,994	3,214,971				
2026	3,214,971	100,994	3,113,977				
2027	3,113,977	100,994	3,012,984				
2028	3,012,984	100,994	2,911,990				
2029	2,911,990	100,994	2,810,996				
2030	2,810,996	100,994	2,710,002				
2031	2,710,002	100,994	2,609,008				
2032	2,609,008	100,994	2,508,014				
2033	2,508,014	100,994	2,407,020				
2034	2,407,020	100,994	2,306,027				
2035	2,306,027	100,994	2,205,033				
2036	2,205,033	100,994	2,104,039				
2037	2,104,039	100,994	2,003,045				
2038	2,003,045	100,994	1,902,051				
2039	1,902,051	100,994	1,801,057				
2040	1,801,057	100,994	1,700,063				
2041	1,700,063	100,994	1,599,070				
2042	1,599,070	100,994	1,498,076				
2043	1,498,076	100,994	1,397,082				
2044	1,397,082	100,994	1,296,088				
2045	1,296,088	100,994	1,195,094				
2046	1,195,094	100,994	1,094,100				
2047	1,094,100	100,994	993,106				
2048	993,106	100,994	892,112				
2049	892,112	100,994	791,119				
2050	791,119	100,994	690,125				
2051	690,125	100,994	589,131				
2052	589,131	100,994	488,137				
2053	488,137	100,994	387,143				
2054	387,143	100,994	286,149				
2055	286,149	100,994	185,155				
2056	185,155	100,994	84,162				
2057	84,162	84,162	-				
2058	-	-	-				
2059	-	-	-				
2060	-	-	-				
2061	-	-	-				
2062	-	-	-				
2063	-	-	-				
2064	-	-	-				
2065	-	-	-				
2066	-	-	-				
2067	-	-	-				
2068	-	-	-				
2069	-	-	-				
2070	-	-	-				
2071	-	-	-				
2072	-	-	-				
Project Totals							

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

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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.

OPCo 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.

Project Description: **RTEP ID: b2032 (Rebuild 138 kV Elliott Tap-Poston line)**

	17,870
	17,870
	-

Details		
Investment	118,332	Current Year
Service Year (yyyy)	2013	ROE increase accepted by FERC (Basis Points)
Service Month (1-12)	1	FCR w/o incentives, less depreciation
Useful life	44	FCR w/incentives approved for these facilities, less dep.
CIAC (Yes or No)	No	Annual Depreciation Expense

CUMULATIVE HISTORY OF PROJECTED ANNUAL REVENUE REQUIREMENTS:

Investment Year	Beginning Balance	Depreciation Expense	Ending Balance		RTEP Projected Rev. Req't.From Prior Year Template with Incentives **		
2013	118,332	2,465	115,867		$ -		
2014	115,867	2,689	113,177		$ 25,862		
2015	113,177	2,689	110,488		$ 17,942		
2016	110,488	2,689	107,799		$ 22,706		
2017	107,799	2,689	105,109		$ 22,935		
2018	105,109	2,689	102,420		$ 18,387		
2019	102,420	2,689	99,731				
2020	99,731	2,689	97,041				
2021	97,041	2,689	94,352				
2022	94,352	2,689	91,662				
2023	91,662	2,689	88,973				
2024	88,973	2,689	86,284				
2025	86,284	2,689	83,594				
2026	83,594	2,689	80,905				
2027	80,905	2,689	78,216				
2028	78,216	2,689	75,526				
2029	75,526	2,689	72,837				
2030	72,837	2,689	70,148				
2031	70,148	2,689	67,458				
2032	67,458	2,689	64,769				
2033	64,769	2,689	62,079				
2034	62,079	2,689	59,390				
2035	59,390	2,689	56,701				
2036	56,701	2,689	54,011				
2037	54,011	2,689	51,322				
2038	51,322	2,689	48,633				
2039	48,633	2,689	45,943				
2040	45,943	2,689	43,254				
2041	43,254	2,689	40,565				
2042	40,565	2,689	37,875				
2043	37,875	2,689	35,186				
2044	35,186	2,689	32,496				
2045	32,496	2,689	29,807				
2046	29,807	2,689	27,118				
2047	27,118	2,689	24,428				
2048	24,428	2,689	21,739				
2049	21,739	2,689	19,050				
2050	19,050	2,689	16,360				
2051	16,360	2,689	13,671				
2052	13,671	2,689	10,982				
2053	10,982	2,689	8,292				
2054	8,292	2,689	5,603				
2055	5,603	2,689	2,913				
2056	2,913	2,689	224				
2057	224	224	-				
2058	-	-	-				
2059	-	-	-				
2060	-	-	-				
2061	-	-	-				
2062	-	-	-				
2063	-	-	-				
2064	-	-	-				
2065	-	-	-				
2066	-	-	-				
2067	-	-	-				
2068	-	-	-				
2069	-	-	-				
2070	-	-	-				
2071	-	-	-				
2072	-	-	-				

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.

OPCo 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.

	548,044
	548,044
	-

Project Description: RTEP ID: b1034.2 (Loop the existing South Canton - Wayview 1

Details		
Investment	3,459,640	Current Year
Service Year (yyyy)	2015	ROE increase accepted by FERC (Basis Points)
Service Month (1-12)	3	FCR w/o incentives, less depreciation
Useful life	44	FCR w/incentives approved for these facilities, less dep.
CIAC (Yes or No)	No	Annual Depreciation Expense

CUMULATIVE HISTORY OF PROJECTED ANNUAL REVENUE REQUIREMENTS:

Investment Year	Beginning Balance	Depreciation Expense	Ending Balance		RTEP Projected Rev. Req't.From Prior Year Template with Incentives **		
2015	3,459,640	58,971	3,400,669		$ 652,736		
2016	3,400,669	78,628	3,322,041		$ 666,514		
2017	3,322,041	78,628	3,243,413		$ 674,329		
2018	3,243,413	78,628	3,164,784		$ 563,359		
2019	3,164,784	78,628	3,086,156				
2020	3,086,156	78,628	3,007,528				
2021	3,007,528	78,628	2,928,900				
2022	2,928,900	78,628	2,850,272				
2023	2,850,272	78,628	2,771,643				
2024	2,771,643	78,628	2,693,015				
2025	2,693,015	78,628	2,614,387				
2026	2,614,387	78,628	2,535,759				
2027	2,535,759	78,628	2,457,131				
2028	2,457,131	78,628	2,378,503				
2029	2,378,503	78,628	2,299,874				
2030	2,299,874	78,628	2,221,246				
2031	2,221,246	78,628	2,142,618				
2032	2,142,618	78,628	2,063,990				
2033	2,063,990	78,628	1,985,362				
2034	1,985,362	78,628	1,906,733				
2035	1,906,733	78,628	1,828,105				
2036	1,828,105	78,628	1,749,477				
2037	1,749,477	78,628	1,670,849				
2038	1,670,849	78,628	1,592,221				
2039	1,592,221	78,628	1,513,593				
2040	1,513,593	78,628	1,434,964				
2041	1,434,964	78,628	1,356,336				
2042	1,356,336	78,628	1,277,708				
2043	1,277,708	78,628	1,199,080				
2044	1,199,080	78,628	1,120,452				
2045	1,120,452	78,628	1,041,823				
2046	1,041,823	78,628	963,195				
2047	963,195	78,628	884,567				
2048	884,567	78,628	805,939				
2049	805,939	78,628	727,311				
2050	727,311	78,628	648,683				
2051	648,683	78,628	570,054				
2052	570,054	78,628	491,426				
2053	491,426	78,628	412,798				
2054	412,798	78,628	334,170				
2055	334,170	78,628	255,542				
2056	255,542	78,628	176,913				
2057	176,913	78,628	98,285				
2058	98,285	78,628	19,657				
2059	19,657	19,657	-				
2060	-	-	-				
2061	-	-	-				
2062	-	-	-				
2063	-	-	-				
2064	-	-	-				
2065	-	-	-				
2066	-	-	-				
2067	-	-	-				
2068	-	-	-				
2069	-	-	-				
2070	-	-	-				
2071	-	-	-				
2072	-	-	-				
2073	-	-	-				
2074	-	-	-				
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.

OPCo 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.

Project Description: **RTEP ID: b1034.7 (Replace all obsolete 138kV circuit breakers**

	685,825
	685,825
	-

Details		
Investment	4,474,020	Current Year
Service Year (yyyy)	2013	ROE increase accepted by FERC (Basis Points)
Service Month (1-12)	9	FCR w/o incentives, less depreciation
Useful life	44	FCR w/incentives approved for these facilities, less dep.
CIAC (Yes or No)	No	Annual Depreciation Expense

CUMULATIVE HISTORY OF PROJECTED ANNUAL REVENUE REQUIREMENTS:

Investment Year	Beginning Balance	Depreciation Expense	Ending Balance		RTEP Projected Rev. Req't.From Prior Year Template with Incentives **		
2013	4,474,020	25,421	4,448,599		$ 0		
2014	4,448,599	101,682	4,346,917		$ 95,797		
2015	4,346,917	101,682	4,245,235		$ 660,744		
2016	4,245,235	101,682	4,143,553		$ 821,901		
2017	4,143,553	101,682	4,041,870		$ 828,442		
2018	4,041,870	101,682	3,940,188		$ 652,807		
2019	3,940,188	101,682	3,838,506				
2020	3,838,506	101,682	3,736,824				
2021	3,736,824	101,682	3,635,141				
2022	3,635,141	101,682	3,533,459				
2023	3,533,459	101,682	3,431,777				
2024	3,431,777	101,682	3,330,094				
2025	3,330,094	101,682	3,228,412				
2026	3,228,412	101,682	3,126,730				
2027	3,126,730	101,682	3,025,048				
2028	3,025,048	101,682	2,923,365				
2029	2,923,365	101,682	2,821,683				
2030	2,821,683	101,682	2,720,001				
2031	2,720,001	101,682	2,618,319				
2032	2,618,319	101,682	2,516,636				
2033	2,516,636	101,682	2,414,954				
2034	2,414,954	101,682	2,313,272				
2035	2,313,272	101,682	2,211,589				
2036	2,211,589	101,682	2,109,907				
2037	2,109,907	101,682	2,008,225				
2038	2,008,225	101,682	1,906,543				
2039	1,906,543	101,682	1,804,860				
2040	1,804,860	101,682	1,703,178				
2041	1,703,178	101,682	1,601,496				
2042	1,601,496	101,682	1,499,814				
2043	1,499,814	101,682	1,398,131				
2044	1,398,131	101,682	1,296,449				
2045	1,296,449	101,682	1,194,767				
2046	1,194,767	101,682	1,093,084				
2047	1,093,084	101,682	991,402				
2048	991,402	101,682	889,720				
2049	889,720	101,682	788,038				
2050	788,038	101,682	686,355				
2051	686,355	101,682	584,673				
2052	584,673	101,682	482,991				
2053	482,991	101,682	381,309				
2054	381,309	101,682	279,626				
2055	279,626	101,682	177,944				
2056	177,944	101,682	76,262				
2057	76,262	76,262	-				
2058	-	-	-				
2059	-	-	-				
2060	-	-	-				
2061	-	-	-				
2062	-	-	-				
2063	-	-	-				
2064	-	-	-				
2065	-	-	-				
2066	-	-	-				
2067	-	-	-				
2068	-	-	-				
2069	-	-	-				
2070	-	-	-				
2071	-	-	-				
2072	-	-	-				
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.

OPCo 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. -

-

Project Description: **RTEP ID: b1970 (Reconductor 13 miles of Kammer-West Bellaire 345 kV line)** -

Details		
Investment	-	Current Year
Service Year (yyyy)	2014	ROE increase accepted by FERC (Basis Points)
Service Month (1-12)	12	FCR w/o incentives, less depreciation
Useful life	44	FCR w/incentives approved for these facilities, less dep.
CIAC (Yes or No)	No	Annual Depreciation Expense

CUMULATIVE HISTORY OF PROJECTED ANNUAL REVENUE REQUIREMENTS:

Investment Year	Beginning Balance	Depreciation Expense	Ending Balance		RTEP Projected Rev. Req't.From Prior Year Template with Incentives **		
2014	-	-	-		$ 99,055		
2015	-	-	-		$ 178,664		
2016	-	-	-		$ 174,005		
2017	-	-	-		$ 174,014		
2018	-	-	-		$ 137,768		
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	-	-	-				
2068	-	-	-				
2069	-	-	-				
2070	-	-	-				
2071	-	-	-				
2072	-	-	-				
2073	-	-	-				
Project Totals							

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

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.

OPCo 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.

	1,133,749
	1,133,749
	-

Project Description: **RTEP ID: b2018 (Loop Conesville-Bixby 345 kV circuit into Ohi**

Details		
Investment	7,169,898	Current Year
Service Year (yyyy)	2015	ROE increase accepted by FERC (Basis Points)
Service Month (1-12)	2	FCR w/o incentives, less depreciation
Useful life	44	FCR w/incentives approved for these facilities, less dep.
CIAC (Yes or No)	No	Annual Depreciation Expense

CUMULATIVE HISTORY OF PROJECTED ANNUAL REVENUE REQUIREMENTS:

Investment Year	Beginning Balance	Depreciation Expense	Ending Balance		RTEP Projected Rev. Req't.From Prior Year Template with Incentives **		
2015	7,169,898	135,794	7,034,104		$ 250,071		
2016	7,034,104	162,952	6,871,152		$ 77,068		
2017	6,871,152	162,952	6,708,200		$ 123,326		
2018	6,708,200	162,952	6,545,248		$ 1,165,473		
2019	6,545,248	162,952	6,382,296				
2020	6,382,296	162,952	6,219,343				
2021	6,219,343	162,952	6,056,391				
2022	6,056,391	162,952	5,893,439				
2023	5,893,439	162,952	5,730,487				
2024	5,730,487	162,952	5,567,534				
2025	5,567,534	162,952	5,404,582				
2026	5,404,582	162,952	5,241,630				
2027	5,241,630	162,952	5,078,678				
2028	5,078,678	162,952	4,915,726				
2029	4,915,726	162,952	4,752,773				
2030	4,752,773	162,952	4,589,821				
2031	4,589,821	162,952	4,426,869				
2032	4,426,869	162,952	4,263,917				
2033	4,263,917	162,952	4,100,964				
2034	4,100,964	162,952	3,938,012				
2035	3,938,012	162,952	3,775,060				
2036	3,775,060	162,952	3,612,108				
2037	3,612,108	162,952	3,449,155				
2038	3,449,155	162,952	3,286,203				
2039	3,286,203	162,952	3,123,251				
2040	3,123,251	162,952	2,960,299				
2041	2,960,299	162,952	2,797,347				
2042	2,797,347	162,952	2,634,394				
2043	2,634,394	162,952	2,471,442				
2044	2,471,442	162,952	2,308,490				
2045	2,308,490	162,952	2,145,538				
2046	2,145,538	162,952	1,982,585				
2047	1,982,585	162,952	1,819,633				
2048	1,819,633	162,952	1,656,681				
2049	1,656,681	162,952	1,493,729				
2050	1,493,729	162,952	1,330,777				
2051	1,330,777	162,952	1,167,824				
2052	1,167,824	162,952	1,004,872				
2053	1,004,872	162,952	841,920				
2054	841,920	162,952	678,968				
2055	678,968	162,952	516,015				
2056	516,015	162,952	353,063				
2057	353,063	162,952	190,111				
2058	190,111	162,952	27,159				
2059	27,159	27,159	-				
2060	-	-	-				
2061	-	-	-				
2062	-	-	-				
2063	-	-	-				
2064	-	-	-				
2065	-	-	-				
2066	-	-	-				
2067	-	-	-				
2068	-	-	-				
2069	-	-	-				
2070	-	-	-				
2071	-	-	-				
2072	-	-	-				
2073	-	-	-				
2074	-	-	-				
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.

OPCo 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.

	193,445
	193,445
	-

Project Description: RTEP ID: b1032.4 (Loop the existing South Canton - Wayview 138kV circuit in-and-out of West Canton)

Details		
Investment	1,214,619	Current Year
Service Year (yyyy)	2015	ROE increase accepted by FERC (Basis Points)
Service Month (1-12)	6	FCR w/o incentives, less depreciation
Useful life	44	FCR w/incentives approved for these facilities, less dep.
CIAC (Yes or No)	No	Annual Depreciation Expense

CUMULATIVE HISTORY OF PROJECTED ANNUAL REVENUE REQUIREMENTS:

Investment Year	Beginning Balance	Depreciation Expense	Ending Balance		RTEP Projected Rev. Req't.From Prior Year Template with Incentives **		
2015	1,214,619	13,802	1,200,817		$ 247,850		
2016	1,200,817	27,605	1,173,212		$ 216,823		
2017	1,173,212	27,605	1,145,607		$ 219,628		
2018	1,145,607	27,605	1,118,002		$ 198,829		
2019	1,118,002	27,605	1,090,397				
2020	1,090,397	27,605	1,062,792				
2021	1,062,792	27,605	1,035,187				
2022	1,035,187	27,605	1,007,582				
2023	1,007,582	27,605	979,977				
2024	979,977	27,605	952,372				
2025	952,372	27,605	924,767				
2026	924,767	27,605	897,162				
2027	897,162	27,605	869,557				
2028	869,557	27,605	841,952				
2029	841,952	27,605	814,347				
2030	814,347	27,605	786,742				
2031	786,742	27,605	759,137				
2032	759,137	27,605	731,532				
2033	731,532	27,605	703,927				
2034	703,927	27,605	676,322				
2035	676,322	27,605	648,717				
2036	648,717	27,605	621,112				
2037	621,112	27,605	593,507				
2038	593,507	27,605	565,902				
2039	565,902	27,605	538,297				
2040	538,297	27,605	510,692				
2041	510,692	27,605	483,087				
2042	483,087	27,605	455,482				
2043	455,482	27,605	427,877				
2044	427,877	27,605	400,272				
2045	400,272	27,605	372,667				
2046	372,667	27,605	345,062				
2047	345,062	27,605	317,457				
2048	317,457	27,605	289,852				
2049	289,852	27,605	262,247				
2050	262,247	27,605	234,642				
2051	234,642	27,605	207,037				
2052	207,037	27,605	179,432				
2053	179,432	27,605	151,827				
2054	151,827	27,605	124,222				
2055	124,222	27,605	96,617				
2056	96,617	27,605	69,012				
2057	69,012	27,605	41,407				
2058	41,407	27,605	13,802				
2059	13,802	13,802	-				
2060	-	-	-				
2061	-	-	-				
2062	-	-	-				
2063	-	-	-				
2064	-	-	-				
2065	-	-	-				
2066	-	-	-				
2067	-	-	-				
2068	-	-	-				
2069	-	-	-				
2070	-	-	-				
2071	-	-	-				
2072	-	-	-				
2073	-	-	-				
2074	-	-	-				
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.

OPCo 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. — **492,430**

492,430

Project Description: **RTEP ID: b1666 (Build an 8 breaker 138 kV station tapping both circuits of the Fostoria-East Lima 138 kV** — **-**

Details		
Investment	3,059,126	Current Year
Service Year (yyyy)	2015	ROE increase accepted by FERC (Basis Points)
Service Month (1-12)	12	FCR w/o incentives, less depreciation
Useful life	44	FCR w/incentives approved for these facilities, less dep.
CIAC (Yes or No)	No	Annual Depreciation Expense

CUMULATIVE HISTORY OF PROJECTED ANNUAL REVENUE REQUIREMENTS:

Investment Year	Beginning Balance	Depreciation Expense	Ending Balance	RTEP Projected Rev. Req't.From Prior Year Template with Incentives **
2015	3,059,126	-	3,059,126	$ 559,098
2016	3,059,126	69,526	2,989,600	$ 620,362
2017	2,989,600	69,526	2,920,075	$ 646,844
2018	2,920,075	69,526	2,850,549	$ 506,029
2019	2,850,549	69,526	2,781,024	
2020	2,781,024	69,526	2,711,498	
2021	2,711,498	69,526	2,641,972	
2022	2,641,972	69,526	2,572,447	
2023	2,572,447	69,526	2,502,921	
2024	2,502,921	69,526	2,433,396	
2025	2,433,396	69,526	2,363,870	
2026	2,363,870	69,526	2,294,345	
2027	2,294,345	69,526	2,224,819	
2028	2,224,819	69,526	2,155,293	
2029	2,155,293	69,526	2,085,768	
2030	2,085,768	69,526	2,016,242	
2031	2,016,242	69,526	1,946,717	
2032	1,946,717	69,526	1,877,191	
2033	1,877,191	69,526	1,807,665	
2034	1,807,665	69,526	1,738,140	
2035	1,738,140	69,526	1,668,614	
2036	1,668,614	69,526	1,599,089	
2037	1,599,089	69,526	1,529,563	
2038	1,529,563	69,526	1,460,037	
2039	1,460,037	69,526	1,390,512	
2040	1,390,512	69,526	1,320,986	
2041	1,320,986	69,526	1,251,461	
2042	1,251,461	69,526	1,181,935	
2043	1,181,935	69,526	1,112,409	
2044	1,112,409	69,526	1,042,884	
2045	1,042,884	69,526	973,358	
2046	973,358	69,526	903,833	
2047	903,833	69,526	834,307	
2048	834,307	69,526	764,782	
2049	764,782	69,526	695,256	
2050	695,256	69,526	625,730	
2051	625,730	69,526	556,205	
2052	556,205	69,526	486,679	
2053	486,679	69,526	417,154	
2054	417,154	69,526	347,628	
2055	347,628	69,526	278,102	
2056	278,102	69,526	208,577	
2057	208,577	69,526	139,051	
2058	139,051	69,526	69,526	
2059	69,526	69,526	0	
2060	0	0	-	
2061	-	-	-	
2062	-	-	-	
2063	-	-	-	
2064	-	-	-	
2065	-	-	-	
2066	-	-	-	
2067	-	-	-	
2068	-	-	-	
2069	-	-	-	
2070	-	-	-	
2071	-	-	-	
2072	-	-	-	
2073	-	-	-	
2074	-	-	-	
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.

OPCo 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.

Project Description: **RTEP ID: b1957 (Terminate Transformer #2 at SW Lima in new**

	349,175
	349,175
	-

Details		
Investment	2,169,182	Current Year
Service Year (yyyy)	2015	ROE increase accepted by FERC (Basis Points)
Service Month (1-12)	12	FCR w/o incentives, less depreciation
Useful life	44	FCR w/incentives approved for these facilities, less dep.
CIAC (Yes or No)	No	Annual Depreciation Expense

CUMULATIVE HISTORY OF PROJECTED ANNUAL REVENUE REQUIREMENTS:

Investment Year	Beginning Balance	Depreciation Expense	Ending Balance		RTEP Projected Rev. Req't.From Prior Year Template with Incentives **		
2015	2,169,182	-	2,169,182		$ 265,269		
2016	2,169,182	49,300	2,119,882		$ 405,050		
2017	2,119,882	49,300	2,070,583		$ 419,228		
2018	2,070,583	49,300	2,021,283		$ 326,706		
2019	2,021,283	49,300	1,971,984				
2020	1,971,984	49,300	1,922,684				
2021	1,922,684	49,300	1,873,384				
2022	1,873,384	49,300	1,824,085				
2023	1,824,085	49,300	1,774,785				
2024	1,774,785	49,300	1,725,486				
2025	1,725,486	49,300	1,676,186				
2026	1,676,186	49,300	1,626,887				
2027	1,626,887	49,300	1,577,587				
2028	1,577,587	49,300	1,528,287				
2029	1,528,287	49,300	1,478,988				
2030	1,478,988	49,300	1,429,688				
2031	1,429,688	49,300	1,380,389				
2032	1,380,389	49,300	1,331,089				
2033	1,331,089	49,300	1,281,789				
2034	1,281,789	49,300	1,232,490				
2035	1,232,490	49,300	1,183,190				
2036	1,183,190	49,300	1,133,891				
2037	1,133,891	49,300	1,084,591				
2038	1,084,591	49,300	1,035,291				
2039	1,035,291	49,300	985,992				
2040	985,992	49,300	936,692				
2041	936,692	49,300	887,393				
2042	887,393	49,300	838,093				
2043	838,093	49,300	788,793				
2044	788,793	49,300	739,494				
2045	739,494	49,300	690,194				
2046	690,194	49,300	640,895				
2047	640,895	49,300	591,595				
2048	591,595	49,300	542,296				
2049	542,296	49,300	492,996				
2050	492,996	49,300	443,696				
2051	443,696	49,300	394,397				
2052	394,397	49,300	345,097				
2053	345,097	49,300	295,798				
2054	295,798	49,300	246,498				
2055	246,498	49,300	197,198				
2056	197,198	49,300	147,899				
2057	147,899	49,300	98,599				
2058	98,599	49,300	49,300				
2059	49,300	49,300	0				
2060	0	0	-				
2061	-	-	-				
2062	-	-	-				
2063	-	-	-				
2064	-	-	-				
2065	-	-	-				
2066	-	-	-				
2067	-	-	-				
2068	-	-	-				
2069	-	-	-				
2070	-	-	-				
2071	-	-	-				
2072	-	-	-				
2073	-	-	-				
2074	-	-	-				
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.

OPCo 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. **99,924**
99,924
-

Project Description: **RTEP ID: b1962 (Add four 765 kV breakers at Kammer)**

Details			
Investment	620,757	Current Year	
Service Year (yyyy)	2,015	ROE increase accepted by FERC (Basis Points)	
Service Month (1-12)	12	FCR w/o incentives, less depreciation	
Useful life	44	FCR w/incentives approved for these facilities, less dep.	
CIAC (Yes or No)	No	Annual Depreciation Expense	

CUMULATIVE HISTORY OF PROJECTED ANNUAL REVENUE REQUIREMENTS:

Investment Year	Beginning Balance	Depreciation Expense	Ending Balance		RTEP Projected Rev. Req't.From Prior Year Template with Incentives **		
2015	620,757	-	620,757		$ 63,382		
2016	620,757	14,108	606,649		$ -		
2017	606,649	14,108	592,541		$ 28,232		
2018	592,541	14,108	578,433				
2019	578,433	14,108	564,325				
2020	564,325	14,108	550,216				
2021	550,216	14,108	536,108				
2022	536,108	14,108	522,000				
2023	522,000	14,108	507,892				
2024	507,892	14,108	493,784				
2025	493,784	14,108	479,676				
2026	479,676	14,108	465,568				
2027	465,568	14,108	451,460				
2028	451,460	14,108	437,352				
2029	437,352	14,108	423,243				
2030	423,243	14,108	409,135				
2031	409,135	14,108	395,027				
2032	395,027	14,108	380,919				
2033	380,919	14,108	366,811				
2034	366,811	14,108	352,703				
2035	352,703	14,108	338,595				
2036	338,595	14,108	324,487				
2037	324,487	14,108	310,379				
2038	310,379	14,108	296,270				
2039	296,270	14,108	282,162				
2040	282,162	14,108	268,054				
2041	268,054	14,108	253,946				
2042	253,946	14,108	239,838				
2043	239,838	14,108	225,730				
2044	225,730	14,108	211,622				
2045	211,622	14,108	197,514				
2046	197,514	14,108	183,405				
2047	183,405	14,108	169,297				
2048	169,297	14,108	155,189				
2049	155,189	14,108	141,081				
2050	141,081	14,108	126,973				
2051	126,973	14,108	112,865				
2052	112,865	14,108	98,757				
2053	98,757	14,108	84,649				
2054	84,649	14,108	70,541				
2055	70,541	14,108	56,432				
2056	56,432	14,108	42,324				
2057	42,324	14,108	28,216				
2058	28,216	14,108	14,108				
2059	14,108	14,108	-				
2060	-	-	-				
2061	-	-	-				
2062	-	-	-				
2063	-	-	-				
2064	-	-	-				
2065	-	-	-				
2066	-	-	-				
2067	-	-	-				
2068	-	-	-				
2069	-	-	-				
2070	-	-	-				
2071	-	-	-				
2072	-	-	-				
2073	-	-	-				
2074	-	-	-				
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.

OPCo 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.

	1,103,114
	1,103,114
	-

Project Description: **RTEP ID: b2019 (Establish Burger 345/138 kV station)**

Details		
Investment	6,852,888	Current Year
Service Year (yyyy)	2015	ROE increase accepted by FERC (Basis Points)
Service Month (1-12)	12	FCR w/o incentives, less depreciation
Useful life	44	FCR w/incentives approved for these facilities, less dep.
CIAC (Yes or No)	No	Annual Depreciation Expense

CUMULATIVE HISTORY OF PROJECTED ANNUAL REVENUE REQUIREMENTS:

Investment Year	Beginning Balance	Depreciation Expense	Ending Balance		RTEP Projected Rev. Req't.From Prior Year Template with Incentives **		
2015	6,852,888	-	6,852,888		$ 1,039,339		
2016	6,852,888	155,747	6,697,141		$ 1,387,490		
2017	6,697,141	155,747	6,541,393		$ 1,411,523		
2018	6,541,393	155,747	6,385,646		$ 1,133,578		
2019	6,385,646	155,747	6,229,898				
2020	6,229,898	155,747	6,074,151				
2021	6,074,151	155,747	5,918,403				
2022	5,918,403	155,747	5,762,656				
2023	5,762,656	155,747	5,606,908				
2024	5,606,908	155,747	5,451,161				
2025	5,451,161	155,747	5,295,413				
2026	5,295,413	155,747	5,139,666				
2027	5,139,666	155,747	4,983,919				
2028	4,983,919	155,747	4,828,171				
2029	4,828,171	155,747	4,672,424				
2030	4,672,424	155,747	4,516,676				
2031	4,516,676	155,747	4,360,929				
2032	4,360,929	155,747	4,205,181				
2033	4,205,181	155,747	4,049,434				
2034	4,049,434	155,747	3,893,686				
2035	3,893,686	155,747	3,737,939				
2036	3,737,939	155,747	3,582,191				
2037	3,582,191	155,747	3,426,444				
2038	3,426,444	155,747	3,270,697				
2039	3,270,697	155,747	3,114,949				
2040	3,114,949	155,747	2,959,202				
2041	2,959,202	155,747	2,803,454				
2042	2,803,454	155,747	2,647,707				
2043	2,647,707	155,747	2,491,959				
2044	2,491,959	155,747	2,336,212				
2045	2,336,212	155,747	2,180,464				
2046	2,180,464	155,747	2,024,717				
2047	2,024,717	155,747	1,868,969				
2048	1,868,969	155,747	1,713,222				
2049	1,713,222	155,747	1,557,475				
2050	1,557,475	155,747	1,401,727				
2051	1,401,727	155,747	1,245,980				
2052	1,245,980	155,747	1,090,232				
2053	1,090,232	155,747	934,485				
2054	934,485	155,747	778,737				
2055	778,737	155,747	622,990				
2056	622,990	155,747	467,242				
2057	467,242	155,747	311,495				
2058	311,495	155,747	155,747				
2059	155,747	155,747	0				
2060	0	0	-				
2061	-	-	-				
2062	-	-	-				
2063	-	-	-				
2064	-	-	-				
2065	-	-	-				
2066	-	-	-				
2067	-	-	-				
2068	-	-	-				
2069	-	-	-				
2070	-	-	-				
2071	-	-	-				
2072	-	-	-				
2073	-	-	-				
2074	-	-	-				
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.

OPCo 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. **948,328**

948,328

Project Description: **RTEP ID: b2017 (Reconductor or rebuild Sporn - Waterford - Muskingum River 345 kV line)** -

Details		
Investment	5,965,093	Current Year
Service Year (yyyy)	2015	ROE increase accepted by FERC (Basis Points)
Service Month (1-12)	5	FCR w/o incentives, less depreciation
Useful life	44	FCR w/incentives approved for these facilities, less dep.
CIAC (Yes or No)	No	Annual Depreciation Expense

CUMULATIVE HISTORY OF PROJECTED ANNUAL REVENUE REQUIREMENTS:

Investment Year	Beginning Balance	Depreciation Expense	Ending Balance		RTEP Projected Rev. Req't.From Prior Year Template with Incentives **		
2015	5,965,093	79,083	5,886,010		$ 805,154		
2016	5,886,010	135,570	5,750,440		$ 1,159,062		
2017	5,750,440	135,570	5,614,870		$ 1,177,370		
2018	5,614,870	135,570	5,479,299		$ 974,758		
2019	5,479,299	135,570	5,343,729				
2020	5,343,729	135,570	5,208,159				
2021	5,208,159	135,570	5,072,589				
2022	5,072,589	135,570	4,937,018				
2023	4,937,018	135,570	4,801,448				
2024	4,801,448	135,570	4,665,878				
2025	4,665,878	135,570	4,530,307				
2026	4,530,307	135,570	4,394,737				
2027	4,394,737	135,570	4,259,167				
2028	4,259,167	135,570	4,123,596				
2029	4,123,596	135,570	3,988,026				
2030	3,988,026	135,570	3,852,456				
2031	3,852,456	135,570	3,716,886				
2032	3,716,886	135,570	3,581,315				
2033	3,581,315	135,570	3,445,745				
2034	3,445,745	135,570	3,310,175				
2035	3,310,175	135,570	3,174,604				
2036	3,174,604	135,570	3,039,034				
2037	3,039,034	135,570	2,903,464				
2038	2,903,464	135,570	2,767,894				
2039	2,767,894	135,570	2,632,323				
2040	2,632,323	135,570	2,496,753				
2041	2,496,753	135,570	2,361,183				
2042	2,361,183	135,570	2,225,612				
2043	2,225,612	135,570	2,090,042				
2044	2,090,042	135,570	1,954,472				
2045	1,954,472	135,570	1,818,901				
2046	1,818,901	135,570	1,683,331				
2047	1,683,331	135,570	1,547,761				
2048	1,547,761	135,570	1,412,191				
2049	1,412,191	135,570	1,276,620				
2050	1,276,620	135,570	1,141,050				
2051	1,141,050	135,570	1,005,480				
2052	1,005,480	135,570	869,909				
2053	869,909	135,570	734,339				
2054	734,339	135,570	598,769				
2055	598,769	135,570	463,199				
2056	463,199	135,570	327,628				
2057	327,628	135,570	192,058				
2058	192,058	135,570	56,488				
2059	56,488	56,488	-				
2060	-	-	-				
2061	-	-	-				
2062	-	-	-				
2063	-	-	-				
2064	-	-	-				
2065	-	-	-				
2066	-	-	-				
2067	-	-	-				
2068	-	-	-				
2069	-	-	-				
2070	-	-	-				
2071	-	-	-				
2072	-	-	-				
2073	-	-	-				
2074	-	-	-				
Project Totals							

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OPCo 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. -
-

Project Description: **RTEP ID: b1032.3 (Convert Ross - Circleville 69kV to 138kV)** -

Details			
Investment	-	Current Year	
Service Year (yyyy)	2015	ROE increase accepted by FERC (Basis Points)	
Service Month (1-12)	6	FCR w/o incentives, less depreciation	
Useful life	44	FCR w/incentives approved for these facilities, less dep.	
CIAC (Yes or No)	No	Annual Depreciation Expense	

CUMULATIVE HISTORY OF PROJECTED ANNUAL REVENUE REQUIREMENTS:

Investment Year	Beginning Balance	Depreciation Expense	Ending Balance		RTEP Projected Rev. Req't.From Prior Year Template with Incentives **		
2015	-	-	-		$ -		
2016	-	-	-		$ 935,319		
2017	-	-	-		$ 1,024,649		
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	-	-	-				
2068	-	-	-				
2069	-	-	-				
2070	-	-	-				
2071	-	-	-				
2072	-	-	-				
2073	-	-	-				
2074	-	-	-				
Project Totals							

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OPCo Worksheet J - ATRR PROJECTED Calculation for PJM Projects Charged to Benefiting Zones Page 20 of 22

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. **2,185**

2,185

Project Description: **RTEP ID: b1032.2 (Two 138kV outlets to Delano and Camp She** -

Details			
Investment	12,892	Current Year	
Service Year (yyyy)	2018	ROE increase accepted by FERC (Basis Points)	
Service Month (1-12)	6	FCR w/o incentives, less depreciation	
Useful life	44	FCR w/incentives approved for these facilities, less dep.	
CIAC (Yes or No)	No	Annual Depreciation Expense	

CUMULATIVE HISTORY OF PROJECTED ANNUAL REVENUE REQUIREMENTS:

Investment Year	Beginning Balance	Depreciation Expense	Ending Balance		RTEP Projected Rev. Req't.From Prior Year Template with Incentives **		
2018	12,892	147	12,746		$ 836,737		
2019	12,746	293	12,453				
2020	12,453	293	12,160				
2021	12,160	293	11,867				
2022	11,867	293	11,574				
2023	11,574	293	11,281				
2024	11,281	293	10,988				
2025	10,988	293	10,695				
2026	10,695	293	10,402				
2027	10,402	293	10,109				
2028	10,109	293	9,816				
2029	9,816	293	9,523				
2030	9,523	293	9,230				
2031	9,230	293	8,937				
2032	8,937	293	8,644				
2033	8,644	293	8,351				
2034	8,351	293	8,058				
2035	8,058	293	7,765				
2036	7,765	293	7,472				
2037	7,472	293	7,179				
2038	7,179	293	6,886				
2039	6,886	293	6,593				
2040	6,593	293	6,300				
2041	6,300	293	6,007				
2042	6,007	293	5,714				
2043	5,714	293	5,421				
2044	5,421	293	5,128				
2045	5,128	293	4,835				
2046	4,835	293	4,542				
2047	4,542	293	4,249				
2048	4,249	293	3,956				
2049	3,956	293	3,663				
2050	3,663	293	3,370				
2051	3,370	293	3,077				
2052	3,077	293	2,784				
2053	2,784	293	2,491				
2054	2,491	293	2,198				
2055	2,198	293	1,905				
2056	1,905	293	1,612				
2057	1,612	293	1,319				
2058	1,319	293	1,026				
2059	1,026	293	733				
2060	733	293	440				
2061	440	293	147				
2062	147	147	-				
2063	-	-	-				
2064	-	-	-				
2065	-	-	-				
2066	-	-	-				
2067	-	-	-				
2068	-	-	-				
2069	-	-	-				
2070	-	-	-				
2071	-	-	-				
2072	-	-	-				
2073	-	-	-				
2074	-	-	-				
2075	-	-	-				
2076	-	-	-				
2077	-	-	-				
Project Totals							

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OPCo 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.

Project Description: **RTEP ID: b1818 (Expand Allen w/ 345/138 kV xfmr. and cut in d**

Details			
Investment	242,015	Current Year	39,370
Service Year (yyyy)	2016	ROE increase accepted by FERC (Basis Points)	
Service Month (1-12)	6	FCR w/o incentives, less depreciation	39,370
Useful life	44	FCR w/incentives approved for these facilities, less dep.	-
CIAC (Yes or No)	No	Annual Depreciation Expense	

CUMULATIVE HISTORY OF PROJECTED ANNUAL REVENUE REQUIREMENTS:

Investment Year	Beginning Balance	Depreciation Expense	Ending Balance		RTEP Projected Rev. Req't.From Prior Year Template with Incentives **		
2016	242,015	2,750	239,265		$ -		
2017	239,265	5,500	233,764		$ 51,695		
2018	233,764	5,500	228,264		$ 40,449		
2019	228,264	5,500	222,764				
2020	222,764	5,500	217,263				
2021	217,263	5,500	211,763				
2022	211,763	5,500	206,263				
2023	206,263	5,500	200,762				
2024	200,762	5,500	195,262				
2025	195,262	5,500	189,762				
2026	189,762	5,500	184,261				
2027	184,261	5,500	178,761				
2028	178,761	5,500	173,261				
2029	173,261	5,500	167,760				
2030	167,760	5,500	162,260				
2031	162,260	5,500	156,760				
2032	156,760	5,500	151,259				
2033	151,259	5,500	145,759				
2034	145,759	5,500	140,259				
2035	140,259	5,500	134,758				
2036	134,758	5,500	129,258				
2037	129,258	5,500	123,758				
2038	123,758	5,500	118,257				
2039	118,257	5,500	112,757				
2040	112,757	5,500	107,257				
2041	107,257	5,500	101,756				
2042	101,756	5,500	96,256				
2043	96,256	5,500	90,756				
2044	90,756	5,500	85,255				
2045	85,255	5,500	79,755				
2046	79,755	5,500	74,255				
2047	74,255	5,500	68,754				
2048	68,754	5,500	63,254				
2049	63,254	5,500	57,754				
2050	57,754	5,500	52,253				
2051	52,253	5,500	46,753				
2052	46,753	5,500	41,253				
2053	41,253	5,500	35,752				
2054	35,752	5,500	30,252				
2055	30,252	5,500	24,752				
2056	24,752	5,500	19,251				
2057	19,251	5,500	13,751				
2058	13,751	5,500	8,251				
2059	8,251	5,500	2,750				
2060	2,750	2,750	-				
2061	-	-	-				
2062	-	-	-				
2063	-	-	-				
2064	-	-	-				
2065	-	-	-				
2066	-	-	-				
2067	-	-	-				
2068	-	-	-				
2069	-	-	-				
2070	-	-	-				
2071	-	-	-				
2072	-	-	-				
2073	-	-	-				
2074	-	-	-				
2075	-	-	-				
Project Totals							

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OPCo 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.

	1,349
	1,349
	-

Project Description: **RTEP ID: b1870 (Replace the Ohio Central transformer #1 450 MVA for 675 MVA transformer)**

Details		
Investment	8,640	Current Year
Service Year (yyyy)	2014	ROE increase accepted by FERC (Basis Points)
Service Month (1-12)	7	FCR w/o incentives, less depreciation
Useful life	44	FCR w/incentives approved for these facilities, less dep.
CIAC (Yes or No)	No	Annual Depreciation Expense

CUMULATIVE HISTORY OF PROJECTED ANNUAL REVENUE REQUIREMENTS:

Investment Year	Beginning Balance	Depreciation Expense	Ending Balance		RTEP Projected Rev. Req't.From Prior Year Template with Incentives **		
2014	8,640	82	8,558		$ -		
2015	8,558	196	8,362		$ -		
2016	8,362	196	8,165				
2017	8,165	196	7,969				
2018	7,969	196	7,773		$ 1,387		
2019	7,773	196	7,576				
2020	7,576	196	7,380				
2021	7,380	196	7,184				
2022	7,184	196	6,987				
2023	6,987	196	6,791				
2024	6,791	196	6,595				
2025	6,595	196	6,398				
2026	6,398	196	6,202				
2027	6,202	196	6,005				
2028	6,005	196	5,809				
2029	5,809	196	5,613				
2030	5,613	196	5,416				
2031	5,416	196	5,220				
2032	5,220	196	5,024				
2033	5,024	196	4,827				
2034	4,827	196	4,631				
2035	4,631	196	4,435				
2036	4,435	196	4,238				
2037	4,238	196	4,042				
2038	4,042	196	3,845				
2039	3,845	196	3,649				
2040	3,649	196	3,453				
2041	3,453	196	3,256				
2042	3,256	196	3,060				
2043	3,060	196	2,864				
2044	2,864	196	2,667				
2045	2,667	196	2,471				
2046	2,471	196	2,275				
2047	2,275	196	2,078				
2048	2,078	196	1,882				
2049	1,882	196	1,685				
2050	1,685	196	1,489				
2051	1,489	196	1,293				
2052	1,293	196	1,096				
2053	1,096	196	900				
2054	900	196	704				
2055	704	196	507				
2056	507	196	311				
2057	311	196	115				
2058	115	115	-				
2059	-	-	-				
2060	-	-	-				
2061	-	-	-				
2062	-	-	-				
2063	-	-	-				
2064	-	-	-				
2065	-	-	-				
2066	-	-	-				
2067	-	-	-				
2068	-	-	-				
2069	-	-	-				
2070	-	-	-				
2071	-	-	-				
2072	-	-	-				
2073	-	-	-				
Project Totals							

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OPCo 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.

	787,895
	787,895
Project Description: RTEP ID: b2833 (Reconductor the Maddox Creek - East Lima 345 kV circuit)	-

Details		
Investment	4,956,908	Current Year
Service Year (yyyy)	2019	ROE increase accepted by FERC (Basis Points)
Service Month (1-12)	7	FCR w/o incentives, less depreciation
Useful life	44	FCR w/incentives approved for these facilities, less dep.
CIAC (Yes or No)	No	Annual Depreciation Expense

CUMULATIVE HISTORY OF PROJECTED ANNUAL REVENUE REQUIREMENTS:

Investment Year	Beginning Balance	Depreciation Expense	Ending Balance		RTEP Projected Rev. Req't.From Prior Year Template with Incentives **		
2019	4,956,908	46,940	4,909,968				
2020	4,909,968	112,657	4,797,311				
2021	4,797,311	112,657	4,684,654				
2022	4,684,654	112,657	4,571,997				
2023	4,571,997	112,657	4,459,340				
2024	4,459,340	112,657	4,346,683				
2025	4,346,683	112,657	4,234,026				
2026	4,234,026	112,657	4,121,369				
2027	4,121,369	112,657	4,008,712				
2028	4,008,712	112,657	3,896,055				
2029	3,896,055	112,657	3,783,398				
2030	3,783,398	112,657	3,670,741				
2031	3,670,741	112,657	3,558,084				
2032	3,558,084	112,657	3,445,427				
2033	3,445,427	112,657	3,332,770				
2034	3,332,770	112,657	3,220,113				
2035	3,220,113	112,657	3,107,456				
2036	3,107,456	112,657	2,994,799				
2037	2,994,799	112,657	2,882,142				
2038	2,882,142	112,657	2,769,485				
2039	2,769,485	112,657	2,656,828				
2040	2,656,828	112,657	2,544,171				
2041	2,544,171	112,657	2,431,514				
2042	2,431,514	112,657	2,318,857				
2043	2,318,857	112,657	2,206,200				
2044	2,206,200	112,657	2,093,543				
2045	2,093,543	112,657	1,980,886				
2046	1,980,886	112,657	1,868,229				
2047	1,868,229	112,657	1,755,572				
2048	1,755,572	112,657	1,642,915				
2049	1,642,915	112,657	1,530,258				
2050	1,530,258	112,657	1,417,601				
2051	1,417,601	112,657	1,304,944				
2052	1,304,944	112,657	1,192,287				
2053	1,192,287	112,657	1,079,630				
2054	1,079,630	112,657	966,973				
2055	966,973	112,657	854,316				
2056	854,316	112,657	741,659				
2057	741,659	112,657	629,002				
2058	629,002	112,657	516,345				
2059	516,345	112,657	403,688				
2060	403,688	112,657	291,031				
2061	291,031	112,657	178,374				
2062	178,374	112,657	65,717				
2063	65,717	65,717	-				
2064	-	-	-				
2065	-	-	-				
2066	-	-	-				
2067	-	-	-				
2068	-	-	-				
2069	-	-	-				
2070	-	-	-				
2071	-	-	-				
2072	-	-	-				
2073	-	-	-				
2074	-	-	-				
2075	-	-	-				
2076	-	-	-				
2077	-	-	-				
2078	-	-	-				
Project Totals							

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AEP East Companies
Cost of Service Formula Rate Using 2019 FF1 Balances
Worksheet L Reserved for Future Use
Ohio Power Company

AEP East Companies
Cost of Service Formula Rate Using Actual/Projected FF1 Balances
Worksheet M Supporting Calculation of Capital Structure and Weighted Average Cost of Capital
Ohio Power Company

		Average Balance of Common Equity				
Line No	Month (a)	Proprietary Capital (b)	Less: Preferred Stock (c)	Less Undistributed Sub Earnings (Acct 216.1) (d)	Less AOCI (Acct 219.1) (e)	Average Balance of Common Equity (f)=(b)-(c)-(d)-(e)
	(Note A)	(FF1 112.16)	(FF1 250-251)	(FF1 112.12)	(FF1 112.15)	
1	December Prior to Rate Year	2,431,969,000			1,169,000	2,430,800,000
2	January	2,462,992,000			1,094,000	2,461,898,000
3	February	2,460,877,000			1,018,000	2,459,859,000
4	March	2,529,439,000			942,000	2,528,497,000
5	April	2,548,199,000			866,000	2,547,333,000
6	May	2,521,890,000			790,000	2,521,100,000
7	June	2,542,025,000			715,000	2,541,310,000
8	July	2,570,844,000			639,000	2,570,205,000
9	August	2,548,594,000			563,000	2,548,031,000
10	September	2,566,076,000			487,000	2,565,589,000
11	October	2,584,095,000			411,000	2,583,684,000
12	November	2,554,993,000			336,000	2,554,657,000
13	December of Rate Year	2,581,175,000			260,000	2,580,915,000
14	Average of the 13 Monthly Balances	2,531,012,923	-	-	714,615	2,530,298,308

		Average Balance of Long Term Debt					
Line No	Month (a)	Acct 221 Bonds (b)	Less: Acct 222 Reacquired Bonds (c)	Acct 223 LT Advances from Assoc. Companies (d)	Acct 224 Senior Unsecured Notes (e)	Less: Fair Value Hedges (f)	Gross Proceeds Outstanding Long-Term Debt (g)=(b)-(c)+(d)+(e)-(f)
	(Note A)	(FF1 112.18)	(FF1 112.19)	(FF1 112.20)	(FF1 112.21)	FF1, page 257, Col. (h) - Note 1	
15	December Prior to Rate Year	(345,400,000)		-	2,028,724,000		1,683,324,000
16	January	(345,400,000)		-	2,028,724,000		1,683,324,000
17	February	(345,400,000)		-	2,028,724,000		1,683,324,000
18	March	(345,400,000)		-	2,528,724,000		2,183,324,000
19	April	(345,400,000)		-	2,528,724,000		2,183,324,000
20	May	(345,400,000)		-	2,528,724,000		2,183,324,000
21	June	(345,400,000)		-	2,528,724,000		2,183,324,000
22	July	(345,400,000)		-	2,528,724,000		2,183,324,000
23	August	(345,400,000)		-	2,528,724,000		2,183,324,000
24	September	(345,400,000)		-	2,528,724,000		2,183,324,000
25	October	(345,400,000)		-	2,528,724,000		2,183,324,000
26	November	(345,400,000)		-	2,528,724,000		2,183,324,000
27	December of Rate Year	(345,400,000)		32,245,000	2,560,969,000		2,247,814,000
28	Average of the 13 Monthly Balances	(345,400,000)	-	2,480,385	2,415,819,769	-	2,072,900,154

NOTE 1: 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. (Page 257 Column H of the FF1)

Development of Cost of Long Term Debt Based on Average Outstanding Balance

	(a)	(b)	(c)	(d)	(e)	(f)	(g)
29	**Annual Interest Expense for 2019**						
30	Interest on Long Term Debt - Accts 221 - 224 (256-257.33.i)			107,778,000			
31	Less: Total Hedge Gain/Expense Accumulated from p 256-257, col. (i) of FERC Form 1 included in Ln 30 and shown in 50 below.			(1,679,213)			
32	Plus: Allowed Hedge Recovery From Ln 55 below.			(1,679,213)			
33	Amort of Debt Discount & Expense - Acct 428 (117.63.c)			962,000			
34	Amort of Loss on Reacquired Debt - Acct 428.1 (117.64.c)			601,000			
35	Less: Amort of Premium on Debt - Acct 429 (117.65.c)						
36	Less: Amort of Gain on Reacquired Debt - Acct 429.1 (117.66.c)						
37	**Total Interest Expense (Ln 30 - 31 + 33 + 34 - 35 - 36)**			109,341,000			
38	**Average Cost of Debt for 2019 (Ln 37/ ln 28 (g))**			**5.27%**			

CALCULATION OF RECOVERABLE HEDGE GAINS/LOSSES

39 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 2019	Less Excludable Amounts (See NOTE on Line 39)	Net Includable Hedge Amount	Remaining Unamortized Balance	Amortization Period Beginning	Amortization Period Ending
40		-		-	0		
41	SUN Cash Flow Hedge - 5.375%	(1,679,213)		(1,679,213)	(2,868,654)	September-09	September-19
42				-			
43				-			
44				-			
45				-			
46				-			
47				-			
48				-			
49					(2,868,654)		
50	Total Hedge Amortization	(1,679,213)	-				

51	Hedge Gain or Loss Prior to Application of Recovery Limit (Sum of Lines 40 to 48)	(1,679,213)
52	Total Average Capital Structure Balance for 2019 (TCOS, Ln 157)	4,603,198,462
53	Financial Hedge Recovery Limit - Five Basis Points of Total Capital	0.0005
54	Limit of Recoverable Amount	2,301,599
55	**Recoverable Hedge Amortization (Lesser of Ln 51 or Ln 54)**	**(1,679,213)**

Development of Cost of Preferred Stock

	Preferred Stock			**Average**	
56	4.125% Series - 100 - Dividend Rate (p. 250-251)	4.125%	4.125%		
57	4.125% Series - 100 - Par Value (p. 250-251)	$ 100.00	$ 100.00		
58	4.125% Series - 100 - Shares O/S (p.250-251)	-	-		
59	4.125% Series - 100 - Monetary Value (Ln 57 * Ln 58)	-	-	-	
60	4.125% Series - 100 - Dividend Amount (Ln 56 * Ln 59)	-	-	-	
61	4.12% Series - 100 - Dividend Rate (p. 250-251)	4.120%	4.120%		
62	4.12% Series - 100 - Par Value (p. 250-251)	$ 100.00	$ 100.00		
63	4.12% Series - 100 - Shares O/S (p.250-251)	-	-		
64	4.12% Series - 100 - Monetary Value (Ln 62 * Ln 63)	-	-	-	
65	4.12% Series - 100 - Dividend Amount (Ln 61 * Ln 64)	-	-	-	
66	4.56% Series - 100 - Dividend Rate (p. 250-251)	4.560%	4.560%		
67	4.56% Series - 100 - Par Value (p. 250-251)	$ 100.00	$ 100.00		
68	4.56% Series - 100 - Shares O/S (p.250-251)	-	-		
69	4.56% Series - 100 - Monetary Value (Ln 67 * Ln 68)	-	-	-	
70	4.56% Series - 100 - Dividend Amount (Ln 66 * Ln 69)	-	-	-	
71	**Balance of Preferred Stock (Lns 59, 64, 69)**	-	-	-	Year End Total Agrees to FF1 p.112, Ln 3, col (c) & (d)
72	**Dividends on Preferred Stock (Lns 60, 65, 70)**	-	-	-	
73	**Average Cost of Preferred Stock (Ln 72/71)**	0.00%	0.00%	**0.00%**	

AEP East Companies
Cost of Service Formula Rate Using Actual/Projected FF1 Balances
Worksheet N - Gains (Losses) on Sales of Plant Held For Future Use
Ohio Power Company

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

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 2019		-		-	

AEP East Companies
Cost of Service Formula Rate Using Actual/Projected FF1 Balances
Worksheet O - Calculation of Postemployment Benefits Other than Pensions Expenses Allocable to Transmission Service
Ohio Power Company

1 Total AEP East Operating Company PBOP Settlement Amount (127,041,505)

Allocation of PBOP Settlement Amount for 2019

Line#	Company	Actual Expense (Including AEPSC Billed OPEB)	Total Company Amount Ratio of Company Actual to Total	Allocation of PBOB Recovery Allowance	Labor Allocator for 2019	Actual Expense	Allowable Expense	One Year Functional Expense (Over)/Under
		(A) (Line 14)	(B)=(A)/Total (A)	(C)=(B) * -127041505	(D)	(E)=(A) * (D)	(F)=(C) * (D)	(G)=(E) - (F)
2	APCo	(10,786,934)	35.95%	(45,673,479)	8.520%	(919,002)	(3,891,191)	2,972,189
3	I&M	(8,341,369)	27.80%	(35,318,595)	3.886%	(324,112)	(1,372,337)	1,048,225
4	KPCo	(2,497,070)	8.32%	(10,572,965)	7.403%	(184,863)	(782,737)	597,874
5	KNGP	(238,736)	0.80%	(1,010,844)	10.505%	(25,079)	(106,188)	81,109
6	OPCo	(7,704,846)	25.68%	(32,623,461)	11.590%	(892,964)	(3,780,944)	2,887,979
7	WPCo	(435,072)	1.45%	(1,842,161)	2.524%	(10,981)	(46,495)	35,514
8	**Sum of Lines 2 to 7**	(30,004,027)		(127,041,505)		(2,357,001)	(9,979,892)	7,622,891

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

		APCo	I&M	KPCo	KNGSPT	OPCo	WPCo	AEP East Total
9	Direct Charged PBOP Expense per Actuarial Report	(10,200,682)	(7,960,375)	(2,383,555)	(210,469)	(6,946,810)	(266,258)	(27,968,149)
10	Additional PBOP Ledger Entries (from Company Records)	222,743	181,345	119,014	(2,018)	(67,394)	(141,891)	
11	Medicare Subsidy							-
12	Net Company Expense (Ln 9 + Ln 10 + Ln 11)	(9,977,939)	(7,779,030)	(2,264,541) -	(212,487)	(7,014,204)	(408,149)	(27,656,349)
13	PBOP Expenses From AEP Service Corporation (from Company Records)	(808,995)	(562,339)	(232,529)	(26,249)	(690,642)	(26,923)	(2,347,678)
14	Company PBOP Expense (Ln 12 + Ln 13)	(10,786,934)	(8,341,369)	(2,497,070)	(238,736)	(7,704,846)	(435,072)	(30,004,027)

For the rate year 2017 and adjusted every four years thereafter, using the annual actuarial report produced for that year, filed as part of the informational filing, Worksheet O will be used to adjust PBOP costs for the next four years (i.e. 2017, 2018, 2019, 2020). If the annual actuarial report projects PBOP costs during the next four years, taken together with the then current cumulative PBOP cost/allowance position, will, absent a change in the PBOP allowance, cause the AEP Companies to over or under collect their cumulative PBOP costs by more than 20% of the projected next four year's total cost, the PBOP allowance shall be adjusted. Worksheet O will be used in the process of updating the PBOP allowance determining (a) the level of cumulative over or under collections during the period since the PBOP allowance was last set, including carrying costs based on the weighted average cost of capital ("WACC") each year from the actual formula rate; (b) the cumulative net present value of projected PBOP costs during the next four years, as estimated by the then current actuarial report, assuming a discount rate equal to the actual formula rate weighted average cost of capital for the prior calendar year; and (c) the cumulative net present value of continued collections over the next four years based on the then effective PBOP allowance, assuming a discount rate equal to the prior year WACC. If the absolute value of (a)+(b)-(c) exceeds 20% of (b), then the PBOP allowance used in the formula rate calculation shall be changed to the value that will cause the projected result (a)+(b)-(c) to equal zero. If the projected over or under collection during the next four years will be less than 20% of (b), then the PBOP allowacance will continue in effect for the next four years at the then effective rate. If it is determined through this procedure AEP Companies will over-recover or under-recover actual PBOP expenses by more than 20% over the subsequent four-year period, AEP shall make a filing under FPA Section 205 to change the PBOP expense stated in the formula rate shown on Worksheet O. No other changes to the formula rate may be included in that filing.

AEP EAST COMPANIES
Worksheet - P CALCULATION OF
TOTAL WEIGHTED AVERAGE DEPRECIATION RATES
FOR TRANSMISSION PLANT PROPERTY ACCOUNT
EFFECTIVE AS OF 6/1/2015
FOR MULTIPLE JURISDICTION COMPANIES
APPALACHIAN POWER COMPANY

		VIRGINIA			WEST VIRGINIA			FERC WHOLESALE			FERC KINGSPORT			COMPANY
		(1)			*(2)*			*(3)*			*(4)*			
	PLANT ACCT.	*VA SCC RATES*	*ALLOCATION FACTOR (5)*	*WTD AVG. DEPREC. RATE*	*PSC OF WV APPROVED RATES*	*ALLOCATION FACTOR (5)*	*WTD AVG. DEPREC. RATE*	*FERC RATES*	*ALLOCATION FACTOR (5)*	*WTD AVG. DEPREC. RATE*	*FERC RATES*	*ALLOCATION FACTOR (5)*	*WTD AVG. DEPREC. RATE*	*WTD AVG. DEPREC. RATE*
TRANSMISSION PLANT														
Land Rights - Va.	350.1	0.66%	1.000000	0.66%										0.66%
Energy Storage Equip	351.0				6.67%	1.000000	6.67%							6.67%
Structures & Improvements	352.0	1.55%	0.469583	0.73%	1.52%	0.437847	0.67%	2.19%	0.036426	0.08%	2.19%	0.056144	0.12%	1.60%
Station Equipment	353.0	1.95%	0.469583	0.92%	1.68%	0.437847	0.74%	2.19%	0.036426	0.08%	2.19%	0.056144	0.12%	1.86%
Towers & Fixtures	354.0	1.14%	0.469583	0.54%	1.54%	0.437847	0.67%	2.19%	0.036426	0.08%	2.19%	0.056144	0.12%	1.41%
Poles & Fixtures	355.0	2.77%	0.469583	1.30%	2.64%	0.437847	1.16%	2.19%	0.036426	0.08%	2.19%	0.056144	0.12%	2.66%
Overhead Conductor	356.0	1.01%	0.469583	0.47%	1.19%	0.437847	0.52%	2.19%	0.036426	0.08%	2.19%	0.056144	0.12%	1.19%
Underground Conduit	357.0	1.23%	0.469583	0.58%	1.45%	0.437847	0.63%	2.19%	0.036426	0.08%	2.19%	0.056144	0.12%	1.41%
Underground Conductors	358.0	3.18%	0.469583	1.49%	7.23%	0.437847	3.17%	2.19%	0.036426	0.08%	2.19%	0.056144	0.12%	4.86%

(1) As approved in VA Case No. PUE 2011-00037 on Nov. 30, 2011.
Depreciation rates were made effective on January 1, 2012.

(2) Approved by PSC of WV Order dated May 26, 2015 in
Case No. 14-1151-E-D effective June 1, 2015.

(3) Approved by FERC March 2, 1990 in Docket ER90-132.

(4) Approved by FERC March 2, 1990 in Docket ER90-133.

(5) Transmission allocation factors are changed annually in January based on
September factors as per the PJM tariff approved in FERC Docket ER08-1329
Attachment H-14B, Part II, pg. 15 of 21.

(6) Energy Storage Equipment is a new account established per FERC Order 784.

GENERAL NOTES:

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

AEP EAST COMPANIES
Worksheet - P CALCULATION OF
TOTAL WEIGHTED AVERAGE DEPRECIATION RATES
FOR TRANSMISSION PLANT PROPERTY ACCOUNT
EFFECTIVE AS OF October 31, 2018
FOR MULTIPLE JURISDICTION COMPANIES
INDIANA MICHIGAN POWER COMPANY

		INDIANA			MICHIGAN			FERC WHOLESALE			COMPANY
		(1)			(2)			(3)			
	PLANT ACCT.	*IURC RATES*	*ALLOCATION FACTOR (4)*	*WTD AVG. DEPREC. RATE*	*MPSC APPROVED RATES*	*ALLOCATION FACTOR (4)*	*WTD AVG. DEPREC. RATE*	*FERC RATES*	*ALLOCATION FACTOR (4)*	*WTD AVG. DEPREC. RATE*	*WTD AVG. DEPREC. RATE*
TRANSMISSION PLANT											
Land Improvements	350.1	1.4800%	0.652103	0.9651%	1.4400%	0.144206	0.2077%	1.4400%	0.203691	0.2933%	1.47%
Structures & Improvements	352.0	1.5500%	0.652103	1.0108%	1.5000%	0.144206	0.2163%	1.5000%	0.203691	0.3055%	1.53%
Station Equipment	353.0	1.8600%	0.652103	1.2129%	1.8400%	0.144206	0.2653%	1.8400%	0.203691	0.3748%	1.85%
Towers & Fixtures	354.0	1.6900%	0.652103	1.1021%	1.5700%	0.144206	0.2264%	1.5700%	0.203691	0.3198%	1.65%
Poles & Fixtures	355.0	2.8500%	0.652103	1.8585%	2.8300%	0.144206	0.4081%	2.8300%	0.203691	0.5764%	2.84%
Overhead Conductors	356.0	1.9700%	0.652103	1.2846%	1.8900%	0.144206	0.2725%	1.8900%	0.203691	0.3850%	1.94%
Underground Conduit	357.0	1.8600%	0.652103	1.2129%	1.7700%	0.144206	0.2552%	1.7700%	0.203691	0.3605%	1.83%
Underground Conductors	358.0	1.7000%	0.652103	1.1086%	1.6600%	0.144206	0.2394%	1.6600%	0.203691	0.3381%	1.69%
Trails & Roads	359.0	1.5000%	0.652103	0.9782%	1.4800%	0.144206	0.2134%	1.4800%	0.203691	0.3015%	1.49%

(1) As approved in Indiana Case No. 44967.
(2) As approved in MICHIGAN Case No. U18370.
(3) FERC wholesale formula rate agreements specify that the depreciation rates in the formula rates change upon approval of MPSC rates in the Michigan jurisdiction.
(4) The rates approved for each jurisdiction are updated when approved by that commission. These demand-based allocation factors for all jurisdictions are updated when new rates are approved in one of the jurisdictions. These allocation factors reflect I&M's 12 monthly Coincident Peaks during test year of the most recent rate case.

GENERAL NOTES:

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

AEP EAST COMPANIES
PJM FORMULA RATE
WORKSHEET P - TRANSMISSION DEPRECIATION RATES
EFFECTIVE AS OF 09/1/2016
FOR SINGLE JURISDICTION COMPANIES
KINGSPORT POWER COMPANY

	PLANT ACCT.	RATES Note 1
TRANSMISSION PLANT		
Structures & Improvements	352.0	1.04%
Station Equipment	353.0	1.49%
Towers & Fixtures	354.0	0.12%
Poles & Fixtures	355.0	2.14%
Overhead Conductors	356.0	0.77%
Underground Conduit	357.0	Note 2
Underground Conductors	358.0	Note 2
Composite Transmission Depreciation Rate		**1.46%**
GENERAL PLANT		
Structures & Improvements	390.0	1.71%
Office Furniture & Equipment	391.0	2.82%
Stores Equipment	393.0	2.22%
Tools Shop & Garage Equipmen	394.0	3.12%
Laboratory Equipment	395.0	3.17%
Communication Equipment	397.0	3.32%
Miscellaneous Equipment	398.0	4.92%
Total General Plant		3.25%

Reference:

Note 1: Rates Approved In Tennessee Regulatory Authority Docket No. 16-00001.
K
Note 2: Kingsport Power Company does not have investment in plant accounts 357 or 358. Therefore, there are no depreciation rates approved for these plant accounts.

General Note

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

AEP EAST COMPANIES
PJM FORMULA RATE
WORKSHEET P - TRANSMISSION DEPRECIATION RATES
EFFECTIVE AS OF 07/1/2015
FOR SINGLE JURISDICTION COMPANIES
KENTUCKY POWER COMPANY

	PLANT ACCT.	RATES Note 1
TRANSMISSION PLANT		
Land Rights	350.1	1.44%
Structures & Improvements	352.0	2.08%
Station Equipment	353.0	2.15%
Towers & Fixtures	354.0	2.61%
Poles & Fixtures	355.0	3.95%
Overhead Conductors	356.0	2.91%
Underground Conduit	357.0	2.99%
Underground Conductors	358.0	2.62%

Reference:

Note 1: Rates Approved in KPSC Case No. 2014-00396.

General Note

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

AEP EAST COMPANIES
PJM FORMULA RATE
WORKSHEET P - TRANSMISSION DEPRECIATION RATES
EFFECTIVE AS OF 1/1/2012
FOR SINGLE JURISDICTION COMPANIES
OHIO POWER COMPANY

	PLANT ACCT.	RATES Note 1
TRANSMISSION PLANT		
Structures & Improvements	352.0	2.02%
Station Equipment	353.0	2.29%
Twrs and Fixtures Above 69 KV	354.0	1.88%
Twrs and Fixtures Below 69 KV	354.0	1.88%
Poles and Fixtures Above 69 KV	355.0	3.52%
Poles and Fixtures Below 69 KV	355.0	3.52%
Overhead Conductor & Devices Above	356.0	1.91%
Overhead Conductor & Devices MSP	356.0	1.91%
Overhead Conductor & Devices 138K	356.0	1.91%
Overhead Conductor & Devices 69KV	356.0	1.91%
Overhead Conductor & Devices CLR	356.0	1.91%
Underground Conduit	357.0	2.26%
Underground Conductors	358.0	3.27%

Reference:

Note 1: These are the weighted average of the depreciation rates in effect for Columbus Southern Power and Ohio Power prior to the merger of Columbus Southern into Ohio Power.

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

AEP EAST COMPANIES
PJM FORMULA RATE
WORKSHEET P - TRANSMISSION DEPRECIATION RATES
EFFECTIVE AS OF 06/1/2015
FOR SINGLE JURISDICTION COMPANIES
WHEELING POWER COMPANY

	PLANT ACCT.	RATES Note 1
TRANSMISSION PLANT		
Structures & Improvements	352.0	0.69%
Station Equipment	353.0	1.70%
Towers & Fixtures	354.0	0.04%
Poles & Fixtures	355.0	2.65%
Overhead Conductors	356.0	1.12%
Underground Conduit	357.0	2.00%
Underground Conductors	358.0	5.00%
Trails & Roads	359.0	-

Note 1: Rates Approved in WV Public Service Commission Case No. 14-1151-E-D.

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

AEP East Companies
Cost of Service Formula Rate Using Actual/Projected FF1 Balances
Worksheet Q - True-up With Interest

Reconciliation Revenue Requirement For Year 2017 Available May 25, 2018		2017 Forecasted Revenue Requirement For Year 2017		True-up Adjustment - Over (Under) Recovery
$309,506,704	-	$318,183,331	=	$8,676,627

Interest Rate on Amount of Refunds or Surcharges from 35.19a		Over (Under) Recovery Plus Interest	Average Monthly Interest Rate	Months	Calculated Interest	Amortization	Surcharge (Refund) Owed
			0.3420%				

An over or under collection will be recovered prorata over 2017, held for 2018 and returned prorate over 2019

Calculation of Interest					Monthly		
January	Year 2017	723,052	0.3420%	12	(29,674)		(752,726)
February	Year 2017	723,052	0.3420%	11	(27,201)		(750,253)
March	Year 2017	723,052	0.3420%	10	(24,728)		(747,781)
April	Year 2017	723,052	0.3420%	9	(22,256)		(745,308)
May	Year 2017	723,052	0.3420%	8	(19,783)		(742,835)
June	Year 2017	723,052	0.3420%	7	(17,310)		(740,362)
July	Year 2017	723,052	0.3420%	6	(14,837)		(737,889)
August	Year 2017	723,052	0.3420%	5	(12,364)		(735,416)
September	Year 2017	723,052	0.3420%	4	(9,891)		(732,944)
October	Year 2017	723,052	0.3420%	3	(7,419)		(730,471)
November	Year 2017	723,052	0.3420%	2	(4,946)		(727,998)
December	Year 2017	723,052	0.3420%	1	(2,473)		(725,525)
					(192,881)		(8,869,508)
					Annual		
January through December	Year 2018	(8,869,508)	0.3420%	12	(364,005)		(9,233,513)
Over (Under) Recovery Plus Interest Amortized and Recovered Over 12 Months					Monthly		
January	Year 2019	9,233,513	0.3420%		(31,579)	786,672	(8,478,420)
February	Year 2019	8,478,420	0.3420%		(28,996)	786,672	(7,720,745)
March	Year 2019	7,720,745	0.3420%		(26,405)	786,672	(6,960,478)
April	Year 2019	6,960,478	0.3420%		(23,805)	786,672	(6,197,611)
May	Year 2019	6,197,611	0.3420%		(21,196)	786,672	(5,432,136)
June	Year 2019	5,432,136	0.3420%		(18,578)	786,672	(4,664,042)
July	Year 2019	4,664,042	0.3420%		(15,951)	786,672	(3,893,321)
August	Year 2019	3,893,321	0.3420%		(13,315)	786,672	(3,119,965)
September	Year 2019	3,119,965	0.3420%		(10,670)	786,672	(2,343,964)
October	Year 2019	2,343,964	0.3420%		(8,016)	786,672	(1,565,309)
November	Year 2019	1,565,309	0.3420%		(5,353)	786,672	(783,990)
December	Year 2019	783,990	0.3420%		(2,681)	786,672	0
					(206,546)		

True-Up Adjustment with Interest	(9,440,059)
Less Over (Under) Recovery	8,676,627
Total Interest	(763,432)

Note 1: The interest rate to be applied to the over recovery or under recovery amounts will be determined using the average monthly FERC interest rate (as determined pursuant to 18 C.F.R. Section 35.19a) for the twenty (20) months from the beginning of the rate year being trued-up through August 31 of the following year.

AEP East Companies
Cost of Service Formula Rate Using Actual/Projected FF1 Balances
Worksheet Q - True-up With Interest

Reconciliation Revenue Requirement For Year 2017 Available May 25, 2018		2017 Forecasted Revenue Requirement For Year 2017		True-up Adjustment - Over (Under) Recovery
$11,556,972	-	$12,195,900	=	$638,928

Interest Rate on Amount of Refunds or Surcharges from 35.19a		Over (Under) Recovery Plus Interest	Average Monthly Interest Rate	Months	Calculated Interest	Amortization	Surcharge (Refund) Owed
			0.3420%				

An over or under collection will be recovered prorata over 2017, held for 2018 and returned prorate over 2019

Calculation of Interest					Monthly		
January	Year 2017	53,244	0.3420%	12	(2,185)		(55,429)
February	Year 2017	53,244	0.3420%	11	(2,003)		(55,247)
March	Year 2017	53,244	0.3420%	10	(1,821)		(55,065)
April	Year 2017	53,244	0.3420%	9	(1,639)		(54,883)
May	Year 2017	53,244	0.3420%	8	(1,457)		(54,701)
June	Year 2017	53,244	0.3420%	7	(1,275)		(54,519)
July	Year 2017	53,244	0.3420%	6	(1,093)		(54,337)
August	Year 2017	53,244	0.3420%	5	(910)		(54,154)
September	Year 2017	53,244	0.3420%	4	(728)		(53,972)
October	Year 2017	53,244	0.3420%	3	(546)		(53,790)
November	Year 2017	53,244	0.3420%	2	(364)		(53,608)
December	Year 2017	53,244	0.3420%	1	(182)		(53,426)
					(14,203)		(653,131)
					Annual		
January through December	Year 2018	(653,131)	0.3420%	12	(26,805)		(679,936)
Over (Under) Recovery Plus Interest Amortized and Recovered Over 12 Months					Monthly		
January	Year 2019	679,936	0.3420%		(2,325)	57,929	(624,332)
February	Year 2019	624,332	0.3420%		(2,135)	57,929	(568,539)
March	Year 2019	568,539	0.3420%		(1,944)	57,929	(512,555)
April	Year 2019	512,555	0.3420%		(1,753)	57,929	(456,379)
May	Year 2019	456,379	0.3420%		(1,561)	57,929	(400,011)
June	Year 2019	400,011	0.3420%		(1,368)	57,929	(343,450)
July	Year 2019	343,450	0.3420%		(1,175)	57,929	(286,696)
August	Year 2019	286,696	0.3420%		(980)	57,929	(229,747)
September	Year 2019	229,747	0.3420%		(786)	57,929	(172,604)
October	Year 2019	172,604	0.3420%		(590)	57,929	(115,266)
November	Year 2019	115,266	0.3420%		(394)	57,929	(57,731)
December	Year 2019	57,731	0.3420%		(197)	57,929	0
					(15,210)		

True-Up Adjustment with Interest	(695,145)
Less Over (Under) Recovery	638,928
Total Interest	(56,217)

Note 1: The interest rate to be applied to the over recovery or under recovery amounts will be determined using the average monthly FERC interest rate (as determined pursuant to 18 C.F.R. Section 35.19a) for the twenty (20) months from the beginning of the rate year being trued-up through August 31 of the following year.

AEP East Companies
Cost of Service Formula Rate Using Actual/Projected FF1 Balances
Worksheet Q - True-up With Interest

Reconciliation Revenue Requirement For Year 2017 Available May 25, 2018		2017 Forecasted Revenue Requirement For Year 2017		True-up Adjustment - Over (Under) Recovery
$689,444	-	$6,024,950	=	$5,335,506

Interest Rate on Amount of Refunds or Surcharges from 35.19a		Over (Under) Recovery Plus Interest	Average Monthly Interest Rate	Months	Calculated Interest	Amortization	Surcharge (Refund) Owed
			0.3420%				

An over or under collection will be recovered prorata over 2017, held for 2018 and returned prorate over 2019

Calculation of Interest					Monthly		
January	Year 2017	444,626	0.3420%	12	(18,247)		(462,873)
February	Year 2017	444,626	0.3420%	11	(16,727)		(461,352)
March	Year 2017	444,626	0.3420%	10	(15,206)		(459,832)
April	Year 2017	444,626	0.3420%	9	(13,686)		(458,311)
May	Year 2017	444,626	0.3420%	8	(12,165)		(456,790)
June	Year 2017	444,626	0.3420%	7	(10,644)		(455,270)
July	Year 2017	444,626	0.3420%	6	(9,124)		(453,749)
August	Year 2017	444,626	0.3420%	5	(7,603)		(452,229)
September	Year 2017	444,626	0.3420%	4	(6,082)		(450,708)
October	Year 2017	444,626	0.3420%	3	(4,562)		(449,187)
November	Year 2017	444,626	0.3420%	2	(3,041)		(447,667)
December	Year 2017	444,626	0.3420%	1	(1,521)		(446,146)
					(118,608)		(5,454,114)
					Annual		
January through December	Year 2018	(5,454,114)	0.3420%	12	(223,837)		(5,677,951)
Over (Under) Recovery Plus Interest Amortized and Recovered Over 12 Months					Monthly		
January	Year 2019	5,677,951	0.3420%		(19,419)	483,747	(5,213,623)
February	Year 2019	5,213,623	0.3420%		(17,831)	483,747	(4,747,707)
March	Year 2019	4,747,707	0.3420%		(16,237)	483,747	(4,280,197)
April	Year 2019	4,280,197	0.3420%		(14,638)	483,747	(3,811,088)
May	Year 2019	3,811,088	0.3420%		(13,034)	483,747	(3,340,376)
June	Year 2019	3,340,376	0.3420%		(11,424)	483,747	(2,868,053)
July	Year 2019	2,868,053	0.3420%		(9,809)	483,747	(2,394,115)
August	Year 2019	2,394,115	0.3420%		(8,188)	483,747	(1,918,556)
September	Year 2019	1,918,556	0.3420%		(6,561)	483,747	(1,441,370)
October	Year 2019	1,441,370	0.3420%		(4,929)	483,747	(962,553)
November	Year 2019	962,553	0.3420%		(3,292)	483,747	(482,098)
December	Year 2019	482,098	0.3420%		(1,649)	483,747	(0)
					(127,011)		
True-Up Adjustment with Interest						(5,804,962)	
Less Over (Under) Recovery						5,335,506	
Total Interest						(469,456)	

Note 1: The interest rate to be applied to the over recovery or under recovery amounts will be determined using the average monthly FERC interest rate (as determined pursuant to 18 C.F.R. Section 35.19a) for the twenty (20) months from the beginning of the rate year being trued-up through August 31 of the following year.