

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

Twelve Months Ended 2024

Indiana Michigan Power Company

Line No.			Total	DA	Allocator	Transmission Amount
1	REVENUE REQUIREMENT (w/o incentives)	(ln 130)				\$213,878,314
2	REVENUE CREDITS	(worksheet E Ln 8) (Note A)	7,405,742		1.00000	\$ 7,405,742
3	Facility Credits under PJM OATT Section 30.9	(worksheet E Ln 9) (Note X)				\$ -
4	REVENUE REQUIREMENT For All Company Facilities	(ln 1 less ln 2 plus ln 3)				<u>\$ 206,472,573</u>

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.

5	Revenue Requirement for PJM Schedule 12 Facilities (w/o incentives) (Worksheet J/K)		8,503,772	DA	1.00000	\$ 8,503,772
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))				15.57%
8	Monthly Rate	(ln 7 / 12)				1.30%
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))				12.08%
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))				4.12%
13	ADDITIONAL REVENUE REQUIREMENT for projects w/ incentive ROE's (Note B) (Worksheet J/K)					
14	REVENUE REQUIREMENT FOR SCHEDULE 1A CHARGES					
15	Total Load Dispatch & Scheduling (Account 561)	Line 75 Below				8,476,507
16	Less: Load Dispatch - Scheduling, System Control and Dispatch Services (321.88.b)					6,006,931
17	Less: Load Dispatch - Reliability, Planning & Standards Development Services (321.92.b)					1,749,841
18	Total 561 Internally Developed Costs	(Line 15 - Line 16 - Line 17)				<u>719,735</u>

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	(1)	(2)	(3)	(4)	(5)
		Data Sources (See "General Notes")	TO Total NOTE C	Allocator	Total Transmission
Line No.	RATE BASE CALCULATION				
19	GROSS PLANT IN SERVICE				
19	Production	(Worksheet A in 14.(b))	5,577,444,179	NA	0.00000
20	Less: Production ARO (Enter Negative)	(Worksheet A in 14.(c))	(517,805,969)	NA	0.00000
21	Transmission	(Worksheet A in 14.(d) & TCOS Ln 134)	1,917,457,988	DA	
22	Less: Transmission ARO (Enter Negative)	(Worksheet A in 14.(e))	-	TP	0.96885
23	Distribution	(Worksheet A in 14.(f))	3,430,035,161	NA	0.00000
24	Less: Distribution ARO (Enter Negative)	(Worksheet A in 14.(g))	-	NA	0.00000
25	General Plant	(Worksheet A in 14.(h))	282,599,589	W/S	0.05121
26	Less: General Plant ARO (Enter Negative)	(Worksheet A in 14.(i))	(1,304,697)	W/S	0.05121
27	Intangible Plant	(Worksheet A in 14.(j))	365,150,697	W/S	0.05121
28	TOTAL GROSS PLANT	(sum Ins 19 to 27)	11,053,576,948	GP	0.171061
				GTD=	0.34740
29	ACCUMULATED DEPRECIATION AND AMORTIZATION				
30	Production	(Worksheet A in 28.(b))	3,210,963,475	NA	0.00000
31	Less: Production ARO (Enter Negative)	(Worksheet A in 28.(c))	(237,378,569)	NA	0.00000
32	Transmission	(Worksheet A in 28.(d) & In 43.(c))	500,791,728	TP1=	0.96747
33	Less: Transmission ARO (Enter Negative)	(Worksheet A in 28.(e))	-	TP1=	0.96747
34	Distribution	(Worksheet A in 28.(f))	809,578,315	NA	0.00000
35	Less: Distribution ARO (Enter Negative)	(Worksheet A in 28.(g))	-	NA	0.00000
36	General Plant	(Worksheet A in 28.(h))	49,769,165	W/S	0.05121
37	Less: General Plant ARO (Enter Negative)	(Worksheet A in 28.(i))	(317,602)	W/S	0.05121
38	Intangible Plant	(Worksheet A in 28.(j))	143,557,381	W/S	0.05121
39	TOTAL ACCUMULATED DEPRECIATION	(sum Ins 30 to 38)	4,476,963,893		
40	NET PLANT IN SERVICE				
41	Production	(In 19 + In 20 - In 30 - In 31)	2,086,053,304		-
42	Transmission	(In 21 + In 22 - In 32 - In 33)	1,416,666,260		1,373,231,760
43	Distribution	(In 23 + In 24 - In 34 - In 35)	2,620,456,846		-
44	General Plant	(In 25 + In 26 - In 36 - In 37)	231,843,329		11,872,186
45	Intangible Plant	(In 27 - In 38)	221,593,317		11,347,306
46	TOTAL NET PLANT IN SERVICE	(sum Ins 41 to 45)	6,576,613,055	NP	0.212336
					1,396,451,251
47	DEFERRED TAX ADJUSTMENTS TO RATE BASE	(Note D)			
48	Account No. 281.1 (enter negative)	(Worksheet B, In 2 & In 5.E)	(19,609,900)	NA	
49	Account No. 282.1 (enter negative)	(Worksheet B, In 7 & In 10.E)	(1,339,615,979)	DA	(243,221,195)
50	Account No. 283.1 (enter negative)	(Worksheet B, In 12 & In 15.E)	(613,087,270)	DA	2,988,500
51	Account No. 190.1	(Worksheet B, In 17 & In 20.E)	784,240,025	DA	13,523,686
52	Account No. 255 (enter negative)	(Worksheet B, In 24 & In 25.E)	-	DA	(1,502,248)
53	TOTAL ADJUSTMENTS	(sum Ins 48 to 52)	(1,188,073,124)		(228,211,256)
54	PLANT HELD FOR FUTURE USE	(Worksheet A in 44.(e) & In 45.(e))	1,320,200	DA	146,534
55	REGULATORY ASSETS	(Worksheet A in 51.(e))	-	DA	-
56	UNFUNDED RESERVES (ENTER NEGATIVE) (NOTE Y)	(Worksheet A in 54.(e))	(347,288)	W/S	0.05121
					(17,784)
57	WORKING CAPITAL	(Note E)			
58	Cash Working Capital	(1/8 * In 78)	4,052,332		3,926,115
59	Transmission Materials & Supplies	(Worksheet C, In 2.(F))	275,977	TP	0.96885
60	A&G Materials & Supplies	(Worksheet C, In 3.(F))	590,627	W/S	0.05121
61	Stores Expense	(Worksheet C, In 4.(F))	-	GP	0.17106
62	Prepayments (Account 165) - Labor Allocated	(Worksheet C, In 8.G)	206,748,496	W/S	0.05121
63	Prepayments (Account 165) - Gross Plant	(Worksheet C, In 8.F)	13,941,094	GP	0.17106
64	Prepayments (Account 165) - Transmission Only	(Worksheet C, In 8.E)	-	DA	1.00000
65	Prepayments (Account 165) - Unallocable	(Worksheet C, In 8.D)	(191,586,971)	NA	0.00000
66	TOTAL WORKING CAPITAL	(sum Ins 58 to 65)	34,021,555		
					17,195,656
67	IPP CONTRIBUTIONS FOR CONSTRUCTION	(Note F) (Worksheet D, In 8.B)	-	DA	1.00000
					-
68	RATE BASE (sum Ins 46, 53, 54, 55, 56, 66, 67)		5,423,534,397		
					1,185,564,402

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Line	(1)	(2)	(3)	(4)	(5)
	EXPENSE, TAXES, RETURN & REVENUE REQUIREMENTS CALCULATION	Data Sources (See "General Notes")	TO Total	Allocator	Total Transmission
No.	OPERATION & MAINTENANCE EXPENSE				
69	Production	321.80.b	802,666,891		
70	Distribution	322.156.b	85,313,164		
71	Customer Related Expense	322 & 323.164,171,178.b	68,442,359		
72	Regional Marketing Expenses	322.131.b	5,226,851		
73	Transmission	321.112.b	295,002,274		
74	TOTAL O&M EXPENSES	(sum Ins 69 to 73)	1,256,651,539		
75	Less: Total Account 561	(Note G) (Worksheet F, In 14.C)	8,476,507		
76	Less: Account 565	(Note H) 321.96.b	254,107,112		
77	Less: Regulatory Deferrals & Amortizations	(Note I) (Worksheet F, In 4.C)	-		
78	Total O&M Allocable to Transmission	(Ins 73 - 75 - 76 - 77)	32,418,656	TP 0.96885	31,408,917
79	Administrative and General	323.197.b (Notes J and M)	114,012,942		
80	Less: Acct. 924, Property Insurance	323.185.b	578,386		
81	Acct. 9260039 PBOP Expense	PBOP Worksheet O Line 9 & 10, (Note K)	(5,902,725)		
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)	(3,895,823)		
84	Acct. 928, Reg. Com. Exp.	323.189.b	17,527,908		
85	Acct. 930.1, Gen. Advert. Exp.	323.191.b	163,405		
86	Acct. 930.2, Misc. Gen. Exp.	323.192.b	7,623,687		
87	Balance of A & G	(In 79 - sum In 80 to In 86)	97,918,104	W/S 0.05121	5,014,170
88	Plus: Acct. 924, Property Insurance	(In 80)	578,386	GP 0.17106	98,939
89	Acct. 928 - Transmission Specific	Worksheet F In 20.(E) (Note L)	305,274	TP 0.96885	295,765
90	Acct 930.1 - Only safety related ads -Direct	Worksheet F In 37.(E) (Note L)	1,336	TP 0.96885	1,295
91	Acct 930.2 - Misc Gen. Exp. - Trans	Worksheet F In 45.(E) (Note L)	553,276	DA 1.00000	553,276
92	Settlement Approved PBOP Recovery	PBOP Worksheet O, Col. C (Note M)	13,786,615	W/S 0.05121	705,931
93	A & G Subtotal	(sum Ins 87 to 92)	113,141,991		6,669,377
94	O & M EXPENSE SUBTOTAL	(In 78 + In 93)	145,560,647		38,078,294
95	Plus: Transmission Lease Payments To Affiliates in Acct 565 (Company Records) (Note H)		-	DA 1.00000	-
96	TOTAL O & M EXPENSE	(In 94 + In 95)	145,560,647		38,078,294
97	DEPRECIATION AND AMORTIZATION EXPENSE				
98	Production	336.2-6.f	392,469,299	NA 0.00000	-
99	Distribution	336.8.f	108,830,279	NA 0.00000	-
100	Transmission	336.7.f	49,663,745	TP1 0.96747	48,048,431
101	General	336.10.f	11,562,404	W/S 0.05121	592,085
102	Intangible	336.1.f	47,862,511	W/S 0.05121	2,456,055
103	TOTAL DEPRECIATION AND AMORTIZATION	(Ln 98+99+100+101+102) (Note N)	610,488,238		51,096,571
104	TAXES OTHER THAN INCOME				
105	Labor Related				
106	Payroll	Worksheet H In 23.(D)	13,975,779	W/S 0.05121	715,669
107	Plant Related				
108	Property	Worksheet H In 23.(C)	78,200,383	DA 0.00000	14,776,123
109	Gross Receipts/Sales & Use	Worksheet H In 23.(F)	4,470,384	NA 0.00000	-
110	Other	Worksheet H In 23.(E)	-	GP 0.17106	-
111	TOTAL OTHER TAXES	(sum Ins 106 to 110)	96,646,546		15,491,792
112	INCOME TAXES	(Note O)			
113	$T = 1 - [(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)$		24.97%		
114	$EIT = [T / (1 - T)] * [(WCLTD / WACC)]$		23.56%		
115	where WCLTD=(In 154) and WACC = (In 157)				
116	and FIT, SIT & p are as given in Note O.				
117	$GRFC = 1 / (1 - T)$ = (from In 113)		1,3329		
118	Amortized Investment Tax Credit (enter negative)	(FF1 p.114, In 19.c)	3,893,472		
119	Excess Deferred Income Tax	(Note U)	(20,528,545)	DA	(3,218,211)
120	Tax Effect of Permanent and Flow-Through Differences	(Note U)	4,059,339	DA	1,793,610
121	Income Tax Calculation	(In 114 * In 126)	96,134,145		21,014,566
122	ITC adjustment	(In 117 * In 118)	5,189,476	GP 0.17106	887,718
123	Excess Deferred Income Tax	(In 117 * In 119)	(27,361,799)		(4,289,443)
124	Tax Effect of Permanent and Flow-Through Differences	(In 117 * In 120)	5,410,554		2,390,641
125	TOTAL INCOME TAXES	(sum Ins 121 to 124)	79,372,377		20,003,482
126	RETURN ON RATE BASE (Rate Base*WACC)	(In 68 * In 157)	408,095,592		89,208,175
127	INTEREST ON IPP CONTRIBUTION FOR CONST. (Note F) (Worksheet D, In 2.(B))		-	DA 1.00000	-
128	(Gains) / Losses on Sales of Plant Held for Future Use (Worksheet N, In 4, Cols. ((F) & (H))		-		-
129	Tax Impact on Net Loss / (Gain) on Sales of Plant Held for Future Use (In 128 * In 114)		-		-
130	TOTAL REVENUE REQUIREMENT		1,340,163,399		213,878,314
	(sum Ins 96, 103, 111, 125, 126, 127, 128, 129)				

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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 Section 1.167(l)-(h)(6)(i).
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 Indiana Michigan 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 (Miscellaneous 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 Corporation. 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)
(In 118) multiplied by (1/(1-T)). If the applicable tax rates are zero enter 0.
Inputs Required:
FIT = 21.00%
SIT = 5.03% (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 (In 145) / Long-Term Debt (In 154). Preferred Stock cost rate = preferred dividends (In 146) / preferred outstanding (In 155).
Common Stock cost rate (ROE) = 10.35%, the rate accepted by FERC in Docket No. ER08-1329. 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 capital 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 liabilities 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
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 Worksheet A Rate Base
 Indiana Michigan Power Company

Gross Plant In Service										
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)
	(Note A)	FF1, page 205 Col.(g) & pg. 204 Col. (b), In 46	FF1, page 205&204, Col.(g)&(b), Ins 15,24,34,44	FF1, page 207 Col.(g) & pg. 206 Col. (b), In 58	Acct. 359.1 FF1, page 207 Col.(g) & pg. 206 Col. (b), In 57	FF1, page 207 Col.(g) & pg. 206 Col. (b), In 75	FF1, page 207 Col.(g) & pg. 206 Col. (b), In 74	FF1, page 207 Col.(g) & pg. 206 Col. (b), In 99	Acct. 399.1 FF1, page 207 Col.(g) & pg. 206 Col. (b), In 98	FF1, page 205 Col.(g) & pg. 204 Col. (b), In 5
1	December Prior to Rate Year	5,523,610,597	517,805,969	1,908,873,627	-	3,315,790,566	-	264,914,294	1,306,691	358,830,292
2	January	5,527,003,964	517,805,969	1,906,579,856	-	3,328,318,865	-	268,102,322	1,306,358	361,430,419
3	February	5,528,998,883	517,805,969	1,905,606,647	-	3,341,044,286	-	271,464,878	1,306,026	363,512,317
4	March	5,535,007,795	517,805,969	1,906,439,725	-	3,357,982,277	-	274,913,912	1,305,693	360,224,741
5	April	5,584,559,574	517,805,969	1,907,681,747	-	3,376,046,431	-	278,380,277	1,305,361	362,192,829
6	May	5,588,073,899	517,805,969	1,913,556,124	-	3,400,215,723	-	281,569,280	1,305,028	364,381,859
7	June	5,590,960,930	517,805,969	1,918,141,927	-	3,421,694,572	-	284,489,230	1,304,696	360,938,167
8	July	5,593,836,200	517,805,969	1,918,402,346	-	3,445,861,113	-	286,199,233	1,304,364	365,327,903
9	August	5,594,259,407	517,805,969	1,920,467,485	-	3,471,803,593	-	287,846,982	1,304,032	369,927,609
10	September	5,597,772,666	517,805,969	1,922,089,850	-	3,496,276,306	-	290,916,386	1,303,700	368,264,861
11	October	5,602,837,043	517,805,969	1,926,476,683	-	3,518,053,647	-	292,875,169	1,303,368	372,607,343
12	November	5,604,140,042	517,805,969	1,932,969,758	-	3,538,668,643	-	294,973,416	1,303,036	378,442,016
13	December of Rate Year	5,635,713,320	517,805,969	1,939,668,069	-	3,578,901,070	-	297,143,281	1,302,704	360,878,707
14	Average of the 13 Monthly Balances	5,577,444,179	517,805,969	1,917,457,988	-	3,430,035,161	-	282,599,589	1,304,697	365,150,697

Accumulated Depreciation										
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)
	(Note A)	FF1, page 219, Ins 20-24, Col. (b)	Company Records (Included in total in Column (b))	FF1, page 219, In 25, Col. (b)	Company Records (Included in total in Column (d))	FF1, page 219, In 26, Col. (b)	Company Records (Included in total in Column (f))	FF1, page 219, In 28, Col. (b)	Company Records (Included in total in Column (h))	FF1, page 200, In 21, Col. (b)
15	December Prior to Rate Year	2,995,095,274	224,477,917	492,352,316	-	780,474,321	-	48,049,845	295,794	147,373,698
16	January	3,023,957,734	226,628,026	493,735,826	-	785,109,019	-	48,279,007	299,432	148,603,431
17	February	3,052,286,238	228,778,134	495,114,349	-	789,784,302	-	48,521,969	303,069	149,876,493
18	March	3,079,926,087	230,928,243	496,490,774	-	794,327,437	-	48,782,782	306,705	145,706,898
19	April	3,169,093,141	233,078,351	497,868,125	-	798,960,788	-	49,057,437	310,340	146,966,953
20	May	3,198,255,323	235,228,460	499,248,134	-	803,640,134	-	49,347,439	313,975	148,259,808
21	June	3,227,519,476	237,378,569	500,640,852	-	808,356,361	-	49,652,889	317,608	143,401,375
22	July	3,257,036,098	239,528,677	502,043,551	-	813,148,364	-	49,970,657	321,240	144,691,422
23	August	3,287,503,806	241,678,786	503,541,573	-	818,974,672	-	50,326,348	324,872	146,054,633
24	September	3,317,670,142	243,828,895	505,044,221	-	824,955,538	-	50,688,638	328,502	140,100,266
25	October	3,348,089,362	245,979,003	506,550,546	-	830,992,186	-	51,062,492	332,132	141,532,133
26	November	3,378,232,752	248,129,112	508,066,060	-	837,259,737	-	51,442,347	335,761	143,036,447
27	December of Rate Year	3,407,859,737	250,279,221	509,596,136	-	838,534,641	-	51,817,294	339,388	120,642,390
28	Average of the 13 Monthly Balances	3,210,963,475	237,378,569	500,791,728	-	809,578,315	-	49,769,165	317,602	143,557,381

Line No	Month (a)	OATT Ancillary Services (GSU) Plant in Service (b)	OATT Ancillary Services (GSU) Accumulated Depreciation (c)	Excluded Plant - Plant in Service (d)	Excluded Plant - Accumulated Depreciation (e)
			Company Records (included in total in column (d) of gross plant above)		
	(Note A)				
29	December Prior to Rate Year	59,722,758	15,510,209		
30	January	59,722,758	15,639,123		
31	February	59,722,758	15,768,036		
32	March	59,722,758	15,896,950		
33	April	59,722,758	16,025,863		
34	May	59,722,758	16,154,776		
35	June	59,722,758	16,283,690		
36	July	59,722,758	16,412,603		
37	August	59,722,758	16,545,475		
38	September	59,722,758	16,678,347		
39	October	59,722,758	16,811,219		
40	November	59,722,758	16,944,091		
41	December of Rate Year	59,722,758	17,076,963		
42	Average of the 13 Monthly Balances	59,722,758	16,288,257	-	-

43 Transmission Accum Depreciation net of GSU 484,503,471

Plant Held For Future Use

(a)	Source of Data (b)	Balance @ December 31, 2024 (c)	Balance @ December 31, 2023 (d)	Average Balance for 2024 (e)
		44	Plant Held For Future Use FF1, page 214, In 47, Col. (d)	1,320,148
45	Transmission Plant Held For Future Use (Included in total on line 44)	146,483	146,586	146,534

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)

	Description	Account			
52					
53a	Accum Prv I/D Worker's Com	2282000	347,288	347,288	347,288
53b					-
53c					-
54	Total		347,288	347,288	347,288

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
Indiana Michigan Power Company

Line Number	(A) Description	(B) Source	(C) Balance @ December 31, 2024	(D) Balance @ December 31, 2023	(E) Average Balance for 2024
1	Account 281				
2	Year End Utility Deferrals	FF1, p. 272 - 273, In 8, Col. (k)	19,356,560	19,863,241	19,609,900
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)	19,356,560	19,863,241	19,609,900
5	Transmission Related Deferrals	Ln 2 - In 3 - In 4	-	-	-
6	Account 282				
7	Year End Utility Deferrals	FF1, p. 274 - 275, In 5, Col. (k)	1,322,309,463	1,356,922,496	1,339,615,979
8	Less: ARO Related Deferrals	WS B-1 - Actual Stmt. AF Ln. 7 (Note 1)	73,465,693	73,465,693	73,465,693
9	Less: Other Excluded Deferrals	WS B-1 - Actual Stmt. AF Ln. 6 (Note 1)	1,007,080,850	1,038,777,334	1,022,929,092
10	Transmission Related Deferrals	Ln 7 - In 8 - In 9	241,762,920	244,679,469	243,221,195
11	Account 283				
12	Year End Utility Deferrals	FF1, p. 276 - 277, In 9, Col. (k)	605,166,584	621,007,955	613,087,270
13	Less: ARO Related Deferrals	WS B-1 - Actual Stmt. AF Ln. 13 (Note 1)	626,703,136	626,703,136	626,703,136
14	Less: Other Excluded Deferrals	WS B-1 - Actual Stmt. AF Ln. 12 (Note 1)	(18,586,660)	(2,668,072)	(10,627,366)
15	Transmission Related Deferrals	Ln 12 - In 13 - In 14	(2,949,892)	(3,027,109)	(2,988,500)
16	Account 190				
17	Year End Utility Deferrals	FF1, p. 234, In 8, Col. (c)	780,738,615	787,741,435	784,240,025
18	Less: ARO Related Deferrals	WS B-2 - Actual Stmt. AG Ln. 4 (Note 1)	702,617,617	702,617,617	702,617,617
19	Less: Other Excluded Deferrals	WS B-2 - Actual Stmt. AG Ln. 3 (Note 1)	64,657,693	71,539,752	68,098,723
20	Transmission Related Deferrals	Ln 17 - In 18 - In 19	13,464,306	13,585,067	13,523,686
21	Account 255				
22	Year End ITC Balances	FF1, p. 266-267, In 8, Col. (h)	10,806,461	14,699,933	12,753,197
23	Less: Balances Not Qualified for Ratebase	Company Records - Note 1	10,806,461	14,699,933	12,753,197
24	ITC Balances Includeable Ratebase	Ln 22 - In 23	-	-	-
25	Transmission Related Deferrals	WS B-1 - Actual Stmt. AF Ln. 20 (Note 1)	1,502,248	1,502,248	1,502,248

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 1.167(l)-(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.

INDIANA MICHIGAN POWER COMPANY, INC.
Worksheet B-3
Excess/ Deficient ADIT Worksheet for Total Company and Functional Balances
For Year Ended December 31, 2024
Debit/(Credit)

A	B	C	D	E
TOTAL COMPANY BALANCES				
Line No.	Account (NOTE A)	Description of Account	Protected Unprotected	Tax Rate Change Act
Deferred Tax Account (NOTE B)				
1a	1904001	ADFIT - FAS 109 Excess	N/A	TCJA 2017
1b	2811001	ADFIT - Accel Amortization Property	Protected	TCJA 2017
1c	2814001	ADFIT - Accel Amort FAS 109 Excess	Protected	TCJA 2017
1d	2821001	ADFIT - Utility Property	Protected	TCJA 2017
1e	2821001	ADFIT - Utility Property	Unprotected	TCJA 2017
1f	2824001	ADFIT - Utility Property FAS 109 Excess	Protected	TCJA 2017
1g	2824001	ADFIT - Utility Property FAS 109 Excess	Unprotected	TCJA 2017
1h	2831001	ADFIT - Other Utility Deferrals	Unprotected	TCJA 2017
1i	2834001	ADFIT - Other FAS 109 Excess	Unprotected	TCJA 2017
1j	NOTE E			
Regulatory Deferral Accounts				
2a	182.3	Regulatory Asset		TCJA 2017
2b	254	Regulatory Liability		TCJA 2017
2c	NOTE E			
3	Total For Accounting Entires (Sum of Lines 1a through 2b)			
TRANSMISSION FUNCTION BALANCES				
Deferred Tax Account (NOTE B)				
4a	1904001	ADFIT - FAS 109 Excess	N/A	TCJA 2017
4b	2821001	ADFIT - Utility Property	Protected	TCJA 2017
4c	2821001	ADFIT - Utility Property	Unprotected	TCJA 2017
4d	2824001	ADFIT - Utility Property FAS 109 Excess	Protected	TCJA 2017
4e	2824001	ADFIT - Utility Property FAS 109 Excess	Unprotected	TCJA 2017
4f	2831001	ADFIT - Other Utility Deferrals	Unprotected	TCJA 2017
4g	2834001	ADFIT - Other FAS 109 Excess	Unprotected	TCJA 2017
4h	NOTE E			
Regulatory Deferral Accounts				
5a	182.3	Regulatory Asset		TCJA 2017
5b	254	Regulatory Liability		TCJA 2017
5c	NOTE E			
6	Total For Accounting Entires (Sum of Lines 4a through 5b)			

GENERAL NOTE: ADIT Tax balances provided in the formula presented in Attachment H-14B are maintained on both a to formula, the information for excess and deficient ADIT is also presented for both total company and the transmission functional summary.

NOTE A: In order to ensure ratebase neutrality, AEP utilizes the fourth digit of its seven digit FERC Tax subaccount number. The fourth digit of a FERC tax account refers to the utility operations balances or activity. Accounts with the "1" in the fourth position of the account number indicates accounts used to track regulatory accounting requirements balance, which will ensure that in the formula rate the excess or deficiency amounts will be part of ratebase, but the amounts recorded in the "4" accounts will be offset on a net basis in the regulatory asset or liability subaccount.

NOTE B: The amount of the FIT gross up to recorded on regulatory assets and liabilities will be reported on the first line.

NOTE C: The amounts of the remeasurement shown here are as of the effective date of the change in tax rates and will

NOTE D: The ten year amortization period for unprotected excess ADIT is consistent with the period agreed upon by the *Company, et al, 166 FERC ¶ 61,135 (2019)*.

NOTE E: In the event of future tax rate changes, additional lines will be inserted in both the Total Company and Transmission that may be necessary to track that tax rate change.

NOTE F: The amount of excess amortization entries shown in lines 1a through 1j and 4a through 4h are shown as a debit and 6 is the offset recorded to the 410/411 account and will tie to the total company and transmission function service.

F	G	H	I	J
			1/1/2024 Beginning Balances	
Excess Balance at Remeasurement (NOTE C)	Amortization Methodology (NOTE D)	Amortization Period	Excess ADIT Regulatory Offset	Excess ADIT in Utility Deferrals
(11,772,442)	ARAM	Life of Asset		
(410,365,997)	ARAM	Life of Asset		
(148,924,633)	10 Years	1/2018 - 12/2027		
(5,353,470)	10 Years	1/2018 - 12/2027		
			0	-
(82,304,124)	ARAM	Life of Asset		
(14,907,164)	10 Years	1/2018 - 12/2027		
5,174,807	10 Years	1/2018 - 12/2027		
			0	-

tal company and transmission functional basis. Because both sets of numbers are presented in the on on this worksheet. Account 281 only applies to the generation function, so is not presented in the

numbers to identify balances associated with utility operations vs regulatory reporting requirements. A "1" in " designation will be included in the determination of ratebase to be recovered in the formula rate. A "4" designation will be included in the determination of ratebase to be recovered in the formula rate. A "4" designation will be included in the determination of ratebase to be recovered in the formula rate. The excess ADIT amounts recorded in accounts with the "4" designation will be contra to the "1" designation. At the total FERC account level the tax liability or asset will be recorded at the current Federal FIT rate. Account established for this purpose.

of ADIT accounts provided for each specific change in tax rates.

remain static on this workpaper.

Company and its customers and approved for the Company's PJM formula rates. *Appalachian Power*

mission Functional sections above as required to reflect any new ADIT or regulatory deferral accounts

debit or credit to the ADIT account from which it is being amortized. The total in line 3
al amounts of excess or deficient ADIT amortization shown on line 119 of the cost of

K	L	M	N	O	P
	Balance Sheet Entries		Tax Expense Entries		12/31/2024 Er

Balance Sheet Account Reclassifications	182.3	254	410/411 Excess Amortization	410/411 Deferred Tax Expense/ (Benefit)	Excess ADIT Regulatory Offset
					Sum of Cc

					Sum of Cc
					-
					-
					-
					-
					-
					-
					-
					-
					-

				-
				-

- - - - - -

NOTE F

					Sum of Cc
					-
					-
					-
					-
					-
					-
					-
					-
					-

				-
				-

- - - - - -

NOTE F

Q

Ending Balance

R

**Excess ADIT in Utility
Deferrals**

Reference

Cols (I) - (O)	-
	WS B - 2 Col B/C, ADIT item 3.21
-	WS B - 1, Col B/C, ADIT Item 2.06
-	WS B - 1 Cols O+P+Q+R+S , ADIT Item 5.63
-	
	WS B - 1 Col B/C, ADIT Item 5.62
-	WS B - 1 Col B/C, Items 10.30
	WS B - 1 Col B/C, Item 10.33

Company Records
FERC Form 1 p. 278 Ln. 3 Cols, (b) /(f)

-

Cols (I) - (O)

	Company Records
-	WS B - 1 Col Q, ADIT 5.63
-	
	Company Records
-	WS B - 1 Col Q, item 10.30
	Company Records

Company Records
Company Records

-

TAX CUT and JOBS ACT of 2017

A	B	C	D	E	F=E/C	G	H = E +G	I	J = C - H
Line No.	Utility Account	12/31/17 Pre-remeasurement Balance	Reference	Remeasurement Amount (NOTE 1)	Remeasurement Percentage (NOTE 2)	Adjustments (NOTE 3)	Total Excess/Deficiency by Account (NOTE 4)	Protected / Unprotected	ADIT Deferral After Remeasurement
TOTAL COMPANY									
1	190 - Utility	\$299,354,118	2018 FF1 P. 234 Col (b) Line 8						
2		<u>\$91,360</u>	Less: Deferred State Taxes						
3	1901001	\$299,262,758		114,925,971	38%	(114,925,971)	-		299,262,758
4	2811001	(289,979,890)	2018 FF1 P. 272 Col (b) Line 8	(115,991,956)	40%		(115,991,956)	Protected	(173,987,934)
5	2821001	(1,982,378,027)	2018 FF1 P. 274 Col (b) Line 5	(785,862,991)	40%	(13,641,126)	(568,878,716)	Protected	(1,182,873,910)
6	283 - Utility	(426,174,211)	2018 FF1 P. 276 Col (b) Line 9				(230,625,401)	Unprotected	
7		<u>(70,104,066)</u>	Less: Accrued Deferred State Tax						
8	2831001	(356,070,145)		(141,371,168)	40%	128,567,097	(12,804,072)	Unprotected	(343,266,073)
9	Total	<u>(2,329,165,304.11)</u>	(Sum of Lns. 3+4+5+8)	<u>(928,300,145)</u>		<u>-</u>	<u>(928,300,145)</u>		<u>(1,400,865,159)</u>
TRANSMISSION FUNCTION									
10	1901001	64,030,742	Company Records	25,564,248	40%	(25,564,248)	-		64,030,742
11	2821001	(532,673,986)	Company Records	(211,738,348)	40%	(3,524,425)	(185,402,169)	Protected	(317,411,213)
							(29,860,604)	Unprotected	
12	2831001	(27,241,045)	Company Records	(11,031,930)	40%	29,088,673	18,056,743	Unprotected	(45,297,788)
13	Total	<u>(495,884,289)</u>	(Sum of Lns. 10+11+12)	<u>(197,206,030)</u>		<u>-</u>	<u>(197,206,030)</u>		<u>(298,678,259)</u>

GENERAL NOTE: This worksheet will summarize remeasurement adjustments in ADIT Accounts for both the total company and transmission function required by changes in either Federal or State Income Tax Rates. A new sheet will be included in the working formula for each change to tax rates that may occur while this formula rate is in effect. New pages will be designated by incrementing the suffix letter in the workpaper name (i.e. B-3-A, B-3-B, etc.)

NOTE 1: Amount of remeasurement in Column E will be based on supporting workpapers showing the remeasurement of individual ADIT items in each tax deferral account, and will indicate whether each remeasured ADIT item will be treated as protected or unprotected. The resulting totals will be shown on this worksheet for each ADIT account.

NOTE 2: Remeasurement calculation may not equal 40% of the December 31, 2017 deferral balance because of specific ADIT items that are not subject to remeasurement.

NOTE 3: As part of the remeasurement calculation, the remeasurement ADIT balances in account 1901001 were reclassified to account 2831001 to group nonproperty utility deferrals together as one timing difference.

NOTE 4: Ties to each Operating Companies' Workpaper B-3, Column F, showing the initial remeasurement value determined as a result of the Tax Cut and Jobs Act of 2017.

AEP EAST OPERATING COMPANIES
 APPALACHIAN POWER COMPANY
 ATTACHMENT H-14B
 WORKSHEET-B-3- B
 TAX REMEASUREMENT WORKSHEET
 Debit/(Credit)

WV House Bill 2

A	B	C	D
Line No.	Utility Account	2021 Pre-remeasurement Balance	Reference
TOTAL COMPANY			
1	190/282/283	-\$744,125,741	Total Fed Cumulative ADIT
2		43.256500%	New Apportionment Factor
3		6.500000%	WV State Tax Rate
4		(20,922,379)	WV SDIT Single Factor Apporti
5			
6		(744,125,741)	Total Fed Cumulative ADIT
7		52.269500%	Prior Apportionment Factor
8		6.500000%	WV State Tax Rate
9		(25,281,802)	WV SDIT Three Factor Apport
10			
11		4,359,423.4	Change in Methods (Ln 4 - Ln
12			Federal Offset (@ 21%)
13			
14			
15	Total	-\$25,281,802	Ln 9

TRANSMISSION FUNCTION

16	190/282/283	-\$156,132,408	Total Fed Cumulative ADIT
17		43.256500%	New Apportionment Factor
18		6.500000%	WV State Tax Rate
19		(4,389,932)	WV SDIT Single Factor Apporti
20			
21		(156,132,408)	Total Fed Cumulative ADIT
22		52.269500%	Prior Apportionment Factor
23		6.500000%	WV State Tax Rate
24		(5,304,626)	WV SDIT Three Factor Apport
25			
26		914,693.9	Change in Methods (Ln 19 - Lr
27			Federal Offset (@ 21%)

2026 - Revision of the WV Tax Apportionment Methodolgy from three Factor to One Factor

E	F=E/C	G
Remeasurement Amount (NOTE 1)	Remeasurement Percentage (NOTE 2)	Adjustments (NOTE 3)
onment (NEW)		
ionment Method (PRIOR)		
4,359,423.4 (915,479)	-17%	- -
<u>3,443,945</u>		<u>-</u>

onment (NEW)

ionment Method (PRIOR)

914,693.9 (192,086)	-17%	- -
------------------------	------	--------

722,608

-

its for both the total company and transmission function
in the working formula for each change to tax rates that may
c letter in the workpaper name (i.e. B-3-A, B-3-B, etc.)

wing the remeasurement of individual ADIT items in each tax
d as protected or unprotected. The resulting totals will be

alance because of specific ADIT items that are not subject to

measurement value

H = E +G	I	J = C - H
Total Excess/Deficiency by Account (NOTE 4)	Protected / Unprotected	ADIT Deferral After Remesasurement
		-
4,359,423	Unprotected	(20,922,379)
(915,479)	Unprotected	-
<u>3,443,945</u>		<u>(20,922,379)</u>

		-
914,694	Unprotected	(4,389,932)
(192,086)	Unprotected	-

722,608

(4,389,932)

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

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
Materials & Supplies								
Line Number	Source	Balance @ December 31, 2024	Balance @ December 31, 2023	Average Balance for 2024				
1								
2	Transmission Materials & Supplies	FF1, p. 227, In 8, Col. (c) & (b)	275,977	275,977	275,977			
3	General Materials & Supplies	FF1, p. 227, In 11, Col. (c) & (b)	590,627	590,627	590,627			
4	Stores Expense (Undistributed) - Account 163	FF1, p. 227, In 16, Col. (c) & (b)	0	0	-			

Prepayment Balance Summary (Note 1)

	Average of YE Balance	Excludable Balances	100% Transmission Related	Transmission Plant Related	Transmission Labor Related	Total Included in Ratebase (E)+(F)+(G)	
5							
6	Totals as of December 31, 2024	32,554,213	(198,902,471)	0	17,392,688	214,063,996	231,456,684
7	Totals as of December 31, 2023	25,651,025	(184,271,471)	-	10,489,500	199,432,996	209,922,496
8	Average Balance	29,102,619	(191,586,971)	-	13,941,094	206,748,496	220,689,590

Prepayments Account 165 - Balance @ 12/31/2024

9	Acc. No.	Description	2024 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	14,252,252	-	-	14,252,252	-	14,252,252	Plant Related Insurance Policies
11	16500220	Prepaid Taxes	0	0	-	-	-	-	-
12	16500221	Prepaid Taxes	1,406,724	1,406,724	-	-	-	-	Prepaid Taxes-Distribution
13	1650003	Prepaid Rents	-	-	-	-	-	-	River Transport
14	1650005	Prepaid Employee Benefits	-	-	-	-	-	-	-
15	1650006	Other Prepayments	4,015,056	4,015,056	-	-	-	-	Relates to EPRI dues
16	1650009	Prepaid Carry Cost-Factored AR	704,710	704,710	-	-	-	-	AR Factoring
17	1650010	Prepaid Pension Benefits	89,294,704	-	-	-	89,294,704	89,294,704	Pre-funded Pension Expense
18	1650014	FAS 158 Qual Contra Asset	(89,294,704)	(89,294,704)	-	-	-	-	SFAS 158 Offset
19	165001121	Prepaid Sales Taxes	1,296,617	-	-	-	-	-	Prepaid Sales Tax - Distribution
20	165001221	Prepaid Use Taxes	154,883	154,883	-	-	-	-	Prepaid Use Tax - Distribution
21	1650017	Prepayment - Coal	6,534,303	6,534,303	-	-	-	-	Prepaid Coal
22	1650021	Prepaid Insurance - EIS	3,140,436	-	-	3,140,436	-	3,140,436	Energy INS Services
23	1650022	Prepaid SNF Container Costs	-	-	-	-	-	-	-
24	1650023	Prepaid Lease	329,690	329,690	-	-	-	-	Prepaid Leases-All Functions
25	1650026	Prepaid SNF Costs	-	-	-	-	-	-	-
26	1650030	Other Payments - Long Term	719,542	719,542	-	-	-	-	Other - Dist
27	1650035	PRW without MED-D Benefits	124,769,291	-	-	-	124,769,291	124,769,291	Med-D Benefits
28	1650037	FAS 158 Contra-PRW Exc Med-D	(124,769,291)	(124,769,291)	-	-	-	-	SFAS 158 Offset
29									
30									
31		Subtotal - Form 1, p 111.57.c	32,554,213	(198,902,471)	0	17,392,688	214,063,996	231,456,684	

Prepayments Account 165 - Balance @ 12/31/2023

32	Acc. No.	Description	2023 YE Balance	Excludable Balances	100% Transmission Related	Transmission Plant Related	Transmission Labor Related	Total Included in Ratebase (E)+(F)+(G)	Explanation
33	1650001	Prepaid Insurance	7,349,064	-	-	7,349,064	-	7,349,064	Plant Related Insurance Policies
34	16500220	Prepaid Taxes	0	0	-	-	-	-	-
35	16500221	Prepaid Taxes	1,406,724	1,406,724	-	-	-	-	Prepaid Taxes-Distribution
36	1650003	Prepaid Rents	-	-	-	-	-	-	River Transport
37	1650005	Prepaid Employee Benefits	-	-	-	-	-	-	-
38	1650006	Other Prepayments	4,015,056	4,015,056	-	-	-	-	Relates to EPRI dues
39	1650009	Prepaid Carry Cost-Factored AR	704,710	704,710	-	-	-	-	AR Factoring
40	1650010	Prepaid Pension Benefits	74,663,704	-	-	-	74,663,704	74,663,704	Pre-funded Pension Expense
41	1650014	FAS 158 Qual Contra Asset	(74,663,704)	(74,663,704)	-	-	-	-	SFAS 158 Offset
42	165001121	Prepaid Sales Taxes	1,296,617	-	-	-	-	-	Prepaid Sales Tax - Distribution
43	165001221	Prepaid Use Taxes	154,883	154,883	-	-	-	-	Prepaid Use Tax - Distribution
44	1650017	Prepayment - Coal	6,534,303	6,534,303	-	-	-	-	Prepaid Coal
45	1650021	Prepaid Insurance - EIS	3,140,436	-	-	3,140,436	-	3,140,436	Energy INS Services
46	1650022	Prepaid SNF Container Costs	-	-	-	-	-	-	-
47	1650023	Prepaid Lease	329,690	329,690	-	-	-	-	Prepaid Leases-All Functions
48	1650026	Prepaid SNF Costs	-	-	-	-	-	-	-
49	1650030	Other Payments - Long Term	719,542	719,542	-	-	-	-	Other - Dist
50	1650035	PRW without MED-D Benefits	124,769,291	-	-	-	124,769,291	124,769,291	Med-D Benefits
51	1650037	FAS 158 Contra-PRW Exc Med-D	(124,769,291)	(124,769,291)	-	-	-	-	SFAS 158 Offset
52									
53									
54		Subtotal - Form 1, p 111.57.d	25,651,025	(184,271,471)	-	10,489,500	199,432,996	209,922,496	

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
 Indiana Michigan Power Company

<u>Line Number</u>	<u>(A) Description</u>	<u>(B) 2024</u>
1	Net Funds from IPP Customers 12/31/2023 (2024 FORM 1, P269)	0
2	Interest Accrual (Company Records - Note 1)	0
3	Revenue Credits to Generators (Company Records - Note 1)	0
4	<u>Other Adjustments</u>	
5	Accounting Adjustment (Company Records - Note 1)	0
6		-
7	Net Funds from IPP Customers 12/31/2024 (2024 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 Indiana Michigan Power Company 's general ledger.

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

<u>Line Number</u>	<u>Description</u>	<u>Total Company</u>	<u>Non-Transmission</u>	<u>Transmission</u>
1	Account 450, Forfeited Discounts (FF1 p.300.16.(b); Company Records - Note 1)	5,009,670	5,009,670	-
2	Account 451, Miscellaneous Service Revenues (FF1 p.300.17.(b); Company Records - Note 1)	3,074,412	2,990,512	83,900
3	Account 454, Rent from Electric Property (FF1 p.300.19.(b); Company Records - Note 1)	13,398,265	6,498,418	6,899,847
4	Account 4560015, Associated Business Development - (Company Records - Notes 1, 2)	2,943,575	2,528,597	414,978
5	Account 456 - Other Electric Revenues - (Company Records - Notes 1,2)	67,365,760	67,358,743	7,017
5a	Account 457.1, Regional Control Service Revenues (FF1 p.300.23.(b); Company Records - Note 1)		-	
5b	Account 457.2, Miscellaneous Revenues (FF1 p.300.24.(b); Company Records - Note 1)		-	
6	Subtotal - Other Operating Revenues (Company Total equals (FF1 p. 300.26.(b)))	91,791,681	84,385,940	7,405,742
7	Accounts 4470004 & 5, Revenues from Grandfathered Transmission Contracts - (Company Records - Note 1)		-	
8	Total Other Operating Revenues To Reduce Revenue Requirement	91,791,681	84,385,940	7,405,742

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

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			-
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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
Indiana Michigan Power Company

<u>Line Number</u>	<u>(A) Item No.</u>	<u>(B) Description</u>	<u>(C) 2024 Expense</u>	<u>(D) 100% Non-Transmission</u>	<u>(E) 100% Transmission Specific</u>	<u>(F) Explanation</u>
Regulatory O&M Deferrals & Amortizations						
1						
2						
3						
4		Total	<u>0</u>			
Detail of Account 561 Per FERC Form 1						
5						
6	FF1 p 321.85.b	561.1 - Load Dispatch - Reliability	0			
7	FF1 p 321.86.b	561.2 - Load Dispatch - Monitor & Operate Trans System	303,043			
8	FF1 p 321.87.b	561.3 - Load Dispatch - Trans Service & Scheduling	0			
9	FF1 p 321.88.b	561.4 - Scheduling, System Control & Dispatch	6,006,931			
10	FF1 p 321.89.b	561.5 - Reliability, Planning and Standards Development	416,691			
11	FF1 p 321.90.b	561.6 - Transmission Service Studies	0			
12	FF1 p 321.91.b	561.7 - Generation Interconnection Studies	0			
13	FF1 p 321.92.b	561.8 - Reliability, Planning and Standards Development Services	1,749,841			
14		Total of Account 561	<u>8,476,507</u>			
Account 928						
15	9280000	Regulatory Commission Exp	1,103	975	129	
16	9280001	Regulatory Commission Exp-Adm	12,569,353	12,569,351	2	
17	9280002	Regulatory Commission Exp-Case	2,395,736	2,113,651	282,085	
18	9280005	Reg Com Exp-FERC Trans Cases	48,112	25,054	23,058	
19	9280006	State Publ Serv CommissionFees	2,513,604	2,513,604	-	
20		Total (FERC Form 1 p.323.189.b)	<u>17,527,908</u>	<u>17,222,634</u>	<u>305,274</u>	
Account 930.1						
21	9301000	General Advertising Expenses	13,337	13,337	-	
22	9301001	Newspaper Advertising Space	9,427	8,495	932	
23	9301006	Spec Corporate Comm Info Proj	2,221	2,183	37	
24	9301008	Direct Mail and Handouts	-	-	-	
25	9301010	Publicity	1,543	1,360	183	
26	9301011	Dedications, Tours, & Openings	-	-	-	
27	9301012	Public Opinion Surveys	133,177	133,175	1	
28	9301014	Video Communications	680	601	79	
29	9301015	Other Corporate Comm Exp	3,021	2,917	104	
30						
31						
32						
33						
34						
35						
36						
37		Total (FERC Form 1 p.323.191.b)	<u>163,405</u>	<u>162,069</u>	<u>1,336</u>	
Account 930.2						
38	9302000	Misc General Expenses	5,033,035	5,025,301	7,734	
39	9302003	Corporate & Fiscal Expenses	525,840	479,256	46,584	
40	9302004	Research, Develop&Demonstr Exp	1,704	1,501	202	
41	9302005	Nucl Fac Ins - Replce Engy Cst	-	-	-	
42	9302006	Assoc Business Development Materials Sold	78,498	73,660	4,838	
43	9302007	Assoc Business Development Exp	1,984,611	1,490,692	493,919	
44	9302017	Selling Price Normalization Exp				
45		Total (FERC Form 1 p.323.192.b)	<u>7,623,687</u>	<u>7,070,410</u>	<u>553,276</u>	

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

State Income Tax Rate - Indiana	4.90%	
Apportionment Factor - Note 2	<u>78.10%</u>	
Effective State Tax Rate		3.83%
State Income Tax Rate - Michigan	6.00%	
Apportionment Factor - Note 2	<u>16.50%</u>	
Effective State Tax Rate		0.99%
State Income Tax Rate - West Virginia	6.50%	
Apportionment Factor - Note 2	<u>1.50%</u>	
Effective State Tax Rate		0.10%
Ohio Franchise Tax Rate	0.00%	
Phase-out Factor Note 1	0.00%	
Apportionment Factor - Note 2	<u>0.00%</u>	
Effective State Tax Rate		0.00%
State Income Tax Rate - Kentucky	5.00%	
Apportionment Factor - Note 2	<u>0.90%</u>	
Effective State Tax Rate		0.05%
Missouri Corporation Income Tax Rate	0.00%	
Apportionment Factor - Note 2	<u>0.00%</u>	
Effective State Tax Rate		0.00%
State Income Tax Rate - Illinois	9.50%	
Apportionment Factor - Note 2	<u>0.60%</u>	
Effective State Tax Rate		0.06%
Total Effective State Income Tax Rate		<u><u>5.03%</u></u>

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
Indiana Michigan 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	30,000				30,000
3	Real Estate and Personal Property Taxes					
4	Real and Personal Property - Michigan	53,869,688	53,869,688			
5	Real and Personal Property - Indiana	24,327,512	24,327,512			
6	Real and Personal Property - Other Jurisdictions	3,183	3,183			
7	Payroll Taxes					
8	Federal Insurance Contribution (FICA)	13,607,246		13,607,246		
9	Federal Unemployment Tax	87,822		87,822		
10	State Unemployment Insurance	280,711		280,711		
11	Production Taxes					
12	State Severance Taxes	-				-
13	Miscellaneous Taxes					
14	State Business & Occupation Tax	-				-
15	State Public Service Commission Fees	-			-	
16	State Franchise Taxes	-			-	
17	State Lic/Registration Fee	-			-	
18	Misc. State and Local Tax	-			-	
19	Sales & Use	48,000				48,000
20	Federal Excise Tax	4,392,384				4,392,384
21	Gross Receipts Audit	-				-
22						
23	Total Taxes by Allocable Basis	96,646,546	78,200,383	13,975,779	-	4,470,384

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

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

Functional Property Tax Allocation

	Production	Transmission	Distribution	General	Total	
24	Functionalized Net Plant (TCOS, Lns 41 thru 46)	2,086,053,304	1,416,666,260	2,620,456,846	231,843,329	6,355,019,739
MICHIGAN JURISDICTION						
25	Percentage of Plant in MICHIGAN JURISDICTION	81.82%	16.12%	19.12%	14.00%	
26	Net Plant in MICHIGAN JURISDICTION (Ln 24 * Ln 25)	1,706,795,989	228,392,185	500,951,138	32,467,875	2,468,607,187
27	Less: Net Value of Exempted Generation Plant	533,383,531				
28	Taxable Property Basis (Ln 26 - Ln 27)	1,173,412,458	228,392,185	500,951,138	32,467,875	1,935,223,656
29	Relative Valuation Factor	100.00%	100.00%	100.00%	100.00%	
30	Weighted Net Plant (Ln 28 * Ln 29)	1,173,412,458	228,392,185	500,951,138	32,467,875	
31	General Plant Allocator (Ln 30 / (Total - General Plant))	61.67%	12.00%	26.33%	-100.00%	
32	Functionalized General Plant (Ln 31 * General Plant)	20,022,648	3,897,194	8,548,033	(32,467,875)	-
33	Weighted MICHIGAN JURISDICTION Plant (Ln 30 + 32)	1,193,435,106	232,289,379	509,499,171	0	1,935,223,656
34	Functional Percentage (Ln 33/Total Ln 33)	61.67%	12.00%	26.33%		
INDIANA JURISDICTION						
35	Percentage of Plant in INDIANA JURISDICTION	18.18%	83.88%	80.88%	85.81%	
36	Net Plant in INDIANA JURISDICTION (Ln 24 * Ln 35)	379,257,315	1,188,274,075	2,119,505,708	198,953,060	3,885,990,159
37	Less: Net Value of Exempted Generation Plant	208,142,761				
38	Taxable Property Basis (Ln 36 - Ln 37)	171,114,554	1,188,274,075	2,119,505,708	198,953,060	3,677,847,398
39	Relative Valuation Factor	100.00%	100.00%	100.00%	100.00%	
40	Weighted Net Plant (Ln 38 * Ln 39)	171,114,554	1,188,274,075	2,119,505,708	198,953,060	
41	General Plant Allocator (Ln 40 / (Total - General Plant))	4.92%	34.16%	60.92%	-100.00%	
42	Functionalized General Plant (Ln 41 * General Plant)	9,785,800	67,955,718	121,211,542	(198,953,060)	-
43	Weighted INDIANA JURISDICTION Plant (Ln 40 + 42)	180,900,354	1,256,229,793	2,240,717,250	0	3,677,847,398
44	Functional Percentage (Ln 43/Total Ln 43)	4.92%	34.16%	60.92%		
45	Total Other Jurisdictions: (Line 6 * Net Plant Allocator)	-	676	(0)	-	3,183

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
Indiana Michigan 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
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1 Revenue Taxes

2 Gross Receipts Tax

30,000

30,000

Line No.	(A) Real Estate and Personal Property 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)
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3 Real Estate and Personal Property Taxes Total (Ln 4 + Ln 5 + Ln 6 + Ln 7)

78,200,383

14,776,123

4 Real and Personal Property - Michigan

2023

53,869,688

53,869,688

12.00%

6,466,104

6,466,104

-

-

-

5 Real and Personal Property - Indiana

2023

24,327,512

24,327,512

34.16%

8,309,465

8,309,465

-

-

-

-

-

-

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6 Real and Personal Property - Other

2023

3,183

3,183

17.42%

555

555

-

-

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Line No.	(A) Annual Tax Expenses by Type (Note 1)	(B) Total Company	(C) FERC FORM 1 Tie-Back	(D) FERC FORM 1 Reference
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8 Payroll Taxes

9 Federal Insurance Contribution (FICA)

13,607,246

13,607,246

10 Federal Unemployment Tax

87,822

87,822

11 State Unemployment Insurance

280,711

280,711

12 Production Taxes

13 State Severance Taxes

-

-

14 Miscellaneous Taxes

15 State Business & Occupation Tax

-

-

16 State Public Service Commission Fees

-

-

17 State Franchise Taxes

-

-

18 State Lic/Registration Fee

-

-

19 Misc. State and Local Tax

-

-

20 Sales & Use

48,000

48,000

21 Federal Excise Tax

4,392,384

4,392,384

22 Michigan Single Business Tax

-

-

23 Total Taxes by Allocable Basis (Total Company Amount Ties to FFI p.114, Ln 14.(c))

96,646,546

96,646,546

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 assessed. 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 2024 FF1 Balances
Worksheet I RESERVED FOR FUTURE USE
Indiana Michigan Power Company

AEP East Companies
Cost of Service Formula Rate Using 2024 FF1 Balances
Worksheet J Supporting Calculation of PROJECTED PJM RTEP Project Revenue Requirement Billed to Benefiting Zones
Indiana Michigan Power Company

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

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

ROE w/o incentives (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 through 156)			
	%	Cost	Weighted cost
Long Term Debt	48.55%	4.53%	2.199%
Preferred Stock	0.00%	0.00%	0.000%
Common Stock	51.45%	10.35%	5.325%
		R =	7.525%

SUMMARY OF PROJECTED ANNUAL RTEP REVENUE REQUIREMENTS				
	Rev Require	W Incentives	Incentive Amounts	
PROJECTED YEAR	2024	8,503,772	8,503,772	\$ -

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

Rate Base (TCOS, ln 68)	1,185,564,402
R (from A. above)	7.525%
Return (Rate Base x R)	89,208,175

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

Return (from B. above)	89,208,175
Effective Tax Rate (TCOS, ln 114)	23.56%
Income Tax Calculation (Return x CIT)	21,014,566
ITC Adjustment	887,718
Excess Deferred Income Tax	(4,289,443)
Tax Affect of Permanent Differences	<u>2,390,641</u>
Income Taxes	20,003,482

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)	213,878,314
Lease Payments (TCOS, ln 95)	-
Return (TCOS, ln 126)	89,208,175
Income Taxes (TCOS, ln 125)	20,003,482
Annual Revenue Requirement, Less Lease Payments, Return and Taxes	104,666,657

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

Annual Revenue Requirement, Less Lease Payments, Return and Taxes	104,666,657
Return (from I.B. above)	89,208,175
Income Taxes (from I.C. above)	20,003,482
Annual Revenue Requirement, with Basis Point ROE increase	213,878,314
Depreciation (TCOS, ln 100)	48,048,431
Annual Rev. Req, w/ Basis Point ROE increase, less Depreciation	165,829,883

C. Determine FCR with hypothetical basis point ROE increase.

Net Transmission Plant (TCOS, ln 42)	1,373,231,760
Annual Revenue Requirement, with Basis Point ROE increase	213,878,314
FCR with Basis Point increase in ROE	15.57%
Annual Rev. Req, w/ Basis Point ROE increase, less Dep.	165,829,883
FCR with Basis Point ROE increase, less Depreciation	12.08%
FCR less Depreciation (TCOS, ln 10)	12.08%
Incremental FCR with Basis Point ROE increase, less Depreciation	0.00%

III. Calculation of Composite Depreciation Rate

Average Transmission Plant Balance for 2024 (TCOS, ln 21)	1,857,735,230
Annual Depreciation and Amortization Expense (TCOS, ln 100)	48,048,431
Composite Depreciation Rate	2.59%
Depreciable Life for Composite Depreciation Rate	38.66
Round to nearest whole year	39

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

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

A. Base Plan Facilities

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

Current Projected Year ARR	832,333
Current Projected Year ARR w/ Incentive	832,333
Current Projected Year Incentive ARR	-

Project Description:

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

Details		Current Year	2024
Investment	8,327,150		
Service Year (yyyy)	2009	ROE increase accepted by FERC (Basis Points)	-
Service Month (1-12)	6	FCR w/o incentives, less depreciation	12.08%
Useful life	39	FCR w/incentives approved for these facilities, less dep.	12.08%
CIAC (Yes or No)	No	Annual Depreciation Expense	213,517

CUMULATIVE HISTORY OF PROJECTED ANNUAL REVENUE REQUIREMENTS:

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

Investment Year	Beginning Balance	Depreciation Expense	Ending Balance	RTEP Rev. Req'l. w/o Incentives	RTEP Rev. Req'l. with Incentives **	Incentive Rev. Requirement ##
2009	8,327,150	106,758	8,220,392	1,105,889	1,105,889	\$ -
2010	8,220,392	213,517	8,006,875	1,193,310	1,193,310	\$ -
2011	8,006,875	213,517	7,793,359	1,167,526	1,167,526	\$ -
2012	7,793,359	213,517	7,579,842	1,141,742	1,141,742	\$ -
2013	7,579,842	213,517	7,366,325	1,115,958	1,115,958	\$ -
2014	7,366,325	213,517	7,152,809	1,090,174	1,090,174	\$ -
2015	7,152,809	213,517	6,939,292	1,064,390	1,064,390	\$ -
2016	6,939,292	213,517	6,725,775	1,038,606	1,038,606	\$ -
2017	6,725,775	213,517	6,512,259	1,012,822	1,012,822	\$ -
2018	6,512,259	213,517	6,298,742	987,037	987,037	\$ -
2019	6,298,742	213,517	6,085,225	961,253	961,253	\$ -
2020	6,085,225	213,517	5,871,709	935,469	935,469	\$ -
2021	5,871,709	213,517	5,658,192	909,685	909,685	\$ -
2022	5,658,192	213,517	5,444,675	883,901	883,901	\$ -
2023	5,444,675	213,517	5,231,159	858,117	858,117	\$ -
2024	5,231,159	213,517	5,017,642	832,333	832,333	\$ -
2025	5,017,642	213,517	4,804,125	806,549	806,549	\$ -
2026	4,804,125	213,517	4,590,609	780,765	780,765	\$ -
2027	4,590,609	213,517	4,377,092	754,981	754,981	\$ -
2028	4,377,092	213,517	4,163,575	729,197	729,197	\$ -
2029	4,163,575	213,517	3,950,059	703,413	703,413	\$ -
2030	3,950,059	213,517	3,736,542	677,629	677,629	\$ -
2031	3,736,542	213,517	3,523,025	651,845	651,845	\$ -
2032	3,523,025	213,517	3,309,508	626,061	626,061	\$ -
2033	3,309,508	213,517	3,095,992	600,277	600,277	\$ -
2034	3,095,992	213,517	2,882,475	574,493	574,493	\$ -
2035	2,882,475	213,517	2,668,958	548,709	548,709	\$ -
2036	2,668,958	213,517	2,455,442	522,925	522,925	\$ -
2037	2,455,442	213,517	2,241,925	497,141	497,141	\$ -
2038	2,241,925	213,517	2,028,408	471,357	471,357	\$ -
2039	2,028,408	213,517	1,814,892	445,573	445,573	\$ -
2040	1,814,892	213,517	1,601,375	419,789	419,789	\$ -
2041	1,601,375	213,517	1,387,858	394,005	394,005	\$ -
2042	1,387,858	213,517	1,174,342	368,221	368,221	\$ -
2043	1,174,342	213,517	960,825	342,437	342,437	\$ -
2044	960,825	213,517	747,309	316,653	316,653	\$ -
2045	747,309	213,517	533,792	290,869	290,869	\$ -
2046	533,792	213,517	320,275	265,085	265,085	\$ -
2047	320,275	213,517	106,758	239,301	239,301	\$ -
2048	106,758	106,758	-	113,204	113,204	\$ -
2049	-	-	-	-	-	\$ -
2050	-	-	-	-	-	\$ -
2051	-	-	-	-	-	\$ -
2052	-	-	-	-	-	\$ -
2053	-	-	-	-	-	\$ -
2054	-	-	-	-	-	\$ -
2055	-	-	-	-	-	\$ -
2056	-	-	-	-	-	\$ -
2057	-	-	-	-	-	\$ -
2058	-	-	-	-	-	\$ -
2059	-	-	-	-	-	\$ -
2060	-	-	-	-	-	\$ -
2061	-	-	-	-	-	\$ -
2062	-	-	-	-	-	\$ -
2063	-	-	-	-	-	\$ -
2064	-	-	-	-	-	\$ -
2065	-	-	-	-	-	\$ -
2066	-	-	-	-	-	\$ -
2067	-	-	-	-	-	\$ -
2068	-	-	-	-	-	\$ -
Project Totals		8,327,150		28,438,692	28,438,692	-

RTEP Projected Rev. Req'l. From Prior Year Template w/o Incentives	RTEP Projected Rev. Req'l. From Prior Year Template with Incentives **
\$ -	\$ -
\$ 1,408,114	\$ 1,408,114
\$ 1,487,355	\$ 1,487,355
\$ 1,319,695	\$ 1,319,695
\$ 1,272,484	\$ 1,272,484
\$ 1,249,385	\$ 1,249,385
\$ 1,278,273	\$ 1,278,273
\$ 1,254,654	\$ 1,254,654
\$ 1,132,871	\$ 1,132,871
\$ 933,326	\$ 933,326
\$ 856,880	\$ 856,880
\$ 804,584	\$ 804,584
\$ 786,905	\$ 786,905
\$ 792,610	\$ 792,610

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

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

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

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

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

A. Base Plan Facilities

Facilities receiving incentives accepted by FERC in Docket No. _____

(e.g. ER05-925-000)

Current Projected Year ARR	65,829
Current Projected Year ARR w/ Incentive	65,829
Current Projected Year Incentive ARR	-

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

Details		Current Year	2024
Investment	585,981		
Service Year (yyyy)	2013	ROE increase accepted by FERC (Basis Points)	-
Service Month (1-12)	6	FCR w/o incentives, less depreciation?	12.08%
Useful life	39	FCR w/incentives approved for these facilities, less dep.	12.08%
CIAC (Yes or No)	No	Annual Depreciation Expense	15,025

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

Investment Year	Beginning Balance	Depreciation Expense	Ending Balance	RTEP Rev. Req't. w/o Incentives	RTEP Rev. Req't. with Incentives **	Incentive Rev. Requirement ##
2013	585,981	7,513	578,469	77,821	77,821	-
2014	578,469	15,025	563,443	83,973	83,973	-
2015	563,443	15,025	548,418	82,159	82,159	-
2016	548,418	15,025	533,393	80,344	80,344	-
2017	533,393	15,025	518,368	78,530	78,530	-
2018	518,368	15,025	503,343	76,715	76,715	-
2019	503,343	15,025	488,318	74,901	74,901	-
2020	488,318	15,025	473,293	73,087	73,087	-
2021	473,293	15,025	458,267	71,272	71,272	-
2022	458,267	15,025	443,242	69,458	69,458	-
2023	443,242	15,025	428,217	67,643	67,643	-
2024	428,217	15,025	413,192	65,829	65,829	-
2025	413,192	15,025	398,167	64,015	64,015	-
2026	398,167	15,025	383,142	62,200	62,200	-
2027	383,142	15,025	368,116	60,386	60,386	-
2028	368,116	15,025	353,091	58,571	58,571	-
2029	353,091	15,025	338,066	56,757	56,757	-
2030	338,066	15,025	323,041	54,942	54,942	-
2031	323,041	15,025	308,016	53,128	53,128	-
2032	308,016	15,025	292,991	51,314	51,314	-
2033	292,991	15,025	277,965	49,499	49,499	-
2034	277,965	15,025	262,940	47,685	47,685	-
2035	262,940	15,025	247,915	45,870	45,870	-
2036	247,915	15,025	232,890	44,056	44,056	-
2037	232,890	15,025	217,865	42,241	42,241	-
2038	217,865	15,025	202,840	40,427	40,427	-
2039	202,840	15,025	187,814	38,613	38,613	-
2040	187,814	15,025	172,789	36,798	36,798	-
2041	172,789	15,025	157,764	34,984	34,984	-
2042	157,764	15,025	142,739	33,169	33,169	-
2043	142,739	15,025	127,714	31,355	31,355	-
2044	127,714	15,025	112,689	29,541	29,541	-
2045	112,689	15,025	97,664	27,726	27,726	-
2046	97,664	15,025	82,638	25,912	25,912	-
2047	82,638	15,025	67,613	24,097	24,097	-
2048	67,613	15,025	52,588	22,283	22,283	-
2049	52,588	15,025	37,563	20,468	20,468	-
2050	37,563	15,025	22,538	18,654	18,654	-
2051	22,538	15,025	7,513	16,840	16,840	-
2052	7,513	7,513	-	7,966	7,966	-
2053	-	-	-	-	-	-
2054	-	-	-	-	-	-
2055	-	-	-	-	-	-
2056	-	-	-	-	-	-
2057	-	-	-	-	-	-
2058	-	-	-	-	-	-
2059	-	-	-	-	-	-
2060	-	-	-	-	-	-
2061	-	-	-	-	-	-
2062	-	-	-	-	-	-
2063	-	-	-	-	-	-
2064	-	-	-	-	-	-
2065	-	-	-	-	-	-
2066	-	-	-	-	-	-
2067	-	-	-	-	-	-
2068	-	-	-	-	-	-
2069	-	-	-	-	-	-
2070	-	-	-	-	-	-
2071	-	-	-	-	-	-
2072	-	-	-	-	-	-
Project Totals	585,981			2,001,230	2,001,230	-

RTEP Projected Rev. Req't. From Prior Year Template w/o Incentives	RTEP Projected Rev. Req't. From Prior Year Template with Incentives **
\$ 92,625	\$ 92,625
\$ 87,393	\$ 87,393
\$ 87,463	\$ 87,463
\$ 85,936	\$ 85,936
\$ 77,494	\$ 77,494
\$ 70,215	\$ 70,215
\$ 65,616	\$ 65,616
\$ 61,867	\$ 61,867
\$ 61,041	\$ 61,041
\$ 61,869	\$ 61,869

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

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

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

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

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

A. Base Plan Facilities

Facilities receiving incentives accepted by FERC in Docket No. [REDACTED]

(e.g. ER05-925-000)

Current Projected Year ARR	2,455,323
Current Projected Year ARR w/ Incentive	2,455,323
Current Projected Year Incentive ARR	-

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

Details		Current Year	2024			
Investment	21,957,101					
Service Year (yyyy)	2016	ROE increase accepted by FERC (Basis Points)				
Service Month (1-12)	4	FCR w/o incentives, less depreciation				12.08%
Useful life	39	FCR w/incentives approved for these facilities, less dep.				12.08%
CIAC (Yes or No)	No	Annual Depreciation Expense				563,003

Investment Year	Beginning Balance	Depreciation Expense	Ending Balance	RTEP Rev. Req't w/o Incentives	RTEP Rev. Req't with Incentives **	Incentive Rev. Requirement ##
2013	21,957,101	375,335	21,581,766	3,004,187	3,004,187	-
2014	21,581,766	563,003	21,018,764	3,135,198	3,135,198	-
2015	21,018,764	563,003	20,455,761	3,067,210	3,067,210	-
2016	20,455,761	563,003	19,892,759	2,999,223	2,999,223	-
2017	19,892,759	563,003	19,329,756	2,931,235	2,931,235	-
2018	19,329,756	563,003	18,766,753	2,863,248	2,863,248	-
2019	18,766,753	563,003	18,203,751	2,795,260	2,795,260	-
2020	18,203,751	563,003	17,640,748	2,727,273	2,727,273	-
2021	17,640,748	563,003	17,077,746	2,659,285	2,659,285	-
2022	17,077,746	563,003	16,514,743	2,591,298	2,591,298	-
2023	16,514,743	563,003	15,951,740	2,523,310	2,523,310	-
2024	15,951,740	563,003	15,388,738	2,455,323	2,455,323	-
2025	15,388,738	563,003	14,825,735	2,387,335	2,387,335	-
2026	14,825,735	563,003	14,262,733	2,319,348	2,319,348	-
2027	14,262,733	563,003	13,699,730	2,251,360	2,251,360	-
2028	13,699,730	563,003	13,136,727	2,183,372	2,183,372	-
2029	13,136,727	563,003	12,573,725	2,115,385	2,115,385	-
2030	12,573,725	563,003	12,010,722	2,047,397	2,047,397	-
2031	12,010,722	563,003	11,447,720	1,979,410	1,979,410	-
2032	11,447,720	563,003	10,884,717	1,911,422	1,911,422	-
2033	10,884,717	563,003	10,321,714	1,843,435	1,843,435	-
2034	10,321,714	563,003	9,758,712	1,775,447	1,775,447	-
2035	9,758,712	563,003	9,195,709	1,707,460	1,707,460	-
2036	9,195,709	563,003	8,632,707	1,639,472	1,639,472	-
2037	8,632,707	563,003	8,069,704	1,571,485	1,571,485	-
2038	8,069,704	563,003	7,506,701	1,503,497	1,503,497	-
2039	7,506,701	563,003	6,943,699	1,435,509	1,435,509	-
2040	6,943,699	563,003	6,380,696	1,367,522	1,367,522	-
2041	6,380,696	563,003	5,817,694	1,299,534	1,299,534	-
2042	5,817,694	563,003	5,254,691	1,231,547	1,231,547	-
2043	5,254,691	563,003	4,691,688	1,163,559	1,163,559	-
2044	4,691,688	563,003	4,128,686	1,095,572	1,095,572	-
2045	4,128,686	563,003	3,565,683	1,027,584	1,027,584	-
2046	3,565,683	563,003	3,002,681	959,597	959,597	-
2047	3,002,681	563,003	2,439,678	891,609	891,609	-
2048	2,439,678	563,003	1,876,675	823,622	823,622	-
2049	1,876,675	563,003	1,313,673	755,634	755,634	-
2050	1,313,673	563,003	750,670	687,646	687,646	-
2051	750,670	563,003	187,668	619,659	619,659	-
2052	187,668	187,668	-	198,999	198,999	-
2053	-	-	-	-	-	-
2054	-	-	-	-	-	-
2055	-	-	-	-	-	-
2056	-	-	-	-	-	-
2057	-	-	-	-	-	-
2058	-	-	-	-	-	-
2059	-	-	-	-	-	-
2060	-	-	-	-	-	-
2061	-	-	-	-	-	-
2062	-	-	-	-	-	-
2063	-	-	-	-	-	-
2064	-	-	-	-	-	-
2065	-	-	-	-	-	-
2066	-	-	-	-	-	-
2067	-	-	-	-	-	-
2068	-	-	-	-	-	-
2069	-	-	-	-	-	-
2070	-	-	-	-	-	-
2071	-	-	-	-	-	-
2072	-	-	-	-	-	-
Project Totals		21,957,101		74,545,467	74,545,467	-

CUMULATIVE HISTORY OF PROJECTED ANNUAL REVENUE REQUIREMENTS:

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

RTEP Projected Rev. Req't. From Prior Year Template w/o Incentives	RTEP Projected Rev. Req't. From Prior Year Template with Incentives **		
\$ 1,301,059	\$ 1,301,059		
\$ 3,243,481	\$ 3,243,481		
\$ 3,604,460	\$ 3,604,460		
\$ 3,506,792	\$ 3,506,792		
\$ 3,162,406	\$ 3,162,406		
\$ 2,623,914	\$ 2,623,914		
\$ 2,433,873	\$ 2,433,873		
\$ 2,310,007	\$ 2,310,007		
\$ 2,278,398	\$ 2,278,398		
\$ 2,308,748	\$ 2,308,748		

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

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

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

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

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

A. Base Plan Facilities

Facilities receiving incentives accepted by FERC in Docket No. _____

(e.g. ER05-925-000)

Project Description:

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

Current Projected Year ARR	136,431
Current Projected Year ARR w/ Incentive	136,431
Current Projected Year Incentive ARR	-

Details	Current Year	2024
Investment	1,112,263	-
Service Year (yyyy)	2016	-
Service Month (1-12)	10	-
Useful life	39	12.08%
CIAC (Yes or No)	No	12.08%
	Annual Depreciation Expense	28,520

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

Investment Year	Beginning Balance	Depreciation Expense	Ending Balance	RTEP Rev. Req't. w/o Incentives	RTEP Rev. Req't. with Incentives **	Incentive Rev. Requirement ##
2016	1,112,263	4,753	1,107,509	138,782	138,782	-
2017	1,107,509	28,520	1,078,990	160,539	160,539	-
2018	1,078,990	28,520	1,050,470	157,095	157,095	-
2019	1,050,470	28,520	1,021,951	153,651	153,651	-
2020	1,021,951	28,520	993,431	150,207	150,207	-
2021	993,431	28,520	964,912	146,763	146,763	-
2022	964,912	28,520	936,392	143,319	143,319	-
2023	936,392	28,520	907,873	139,875	139,875	-
2024	907,873	28,520	879,353	136,431	136,431	-
2025	879,353	28,520	850,833	132,987	132,987	-
2026	850,833	28,520	822,314	129,543	129,543	-
2027	822,314	28,520	793,794	126,099	126,099	-
2028	793,794	28,520	765,275	122,655	122,655	-
2029	765,275	28,520	736,755	119,211	119,211	-
2030	736,755	28,520	708,236	115,767	115,767	-
2031	708,236	28,520	679,716	112,323	112,323	-
2032	679,716	28,520	651,197	108,879	108,879	-
2033	651,197	28,520	622,677	105,435	105,435	-
2034	622,677	28,520	594,157	101,991	101,991	-
2035	594,157	28,520	565,638	98,547	98,547	-
2036	565,638	28,520	537,118	95,103	95,103	-
2037	537,118	28,520	508,599	91,659	91,659	-
2038	508,599	28,520	480,079	88,215	88,215	-
2039	480,079	28,520	451,560	84,771	84,771	-
2040	451,560	28,520	423,040	81,327	81,327	-
2041	423,040	28,520	394,521	77,883	77,883	-
2042	394,521	28,520	366,001	74,439	74,439	-
2043	366,001	28,520	337,481	70,995	70,995	-
2044	337,481	28,520	308,962	67,551	67,551	-
2045	308,962	28,520	280,442	64,107	64,107	-
2046	280,442	28,520	251,923	60,663	60,663	-
2047	251,923	28,520	223,403	57,219	57,219	-
2048	223,403	28,520	194,884	53,775	53,775	-
2049	194,884	28,520	166,364	50,331	50,331	-
2050	166,364	28,520	137,845	46,887	46,887	-
2051	137,845	28,520	109,325	43,444	43,444	-
2052	109,325	28,520	80,805	40,000	40,000	-
2053	80,805	28,520	52,286	36,556	36,556	-
2054	52,286	28,520	23,766	33,112	33,112	-
2055	23,766	23,766	-	25,201	25,201	-
2056	-	-	-	-	-	-
2057	-	-	-	-	-	-
2058	-	-	-	-	-	-
2059	-	-	-	-	-	-
2060	-	-	-	-	-	-
2061	-	-	-	-	-	-
2062	-	-	-	-	-	-
2063	-	-	-	-	-	-
2064	-	-	-	-	-	-
2065	-	-	-	-	-	-
2066	-	-	-	-	-	-
2067	-	-	-	-	-	-
2068	-	-	-	-	-	-
2069	-	-	-	-	-	-
2070	-	-	-	-	-	-
2071	-	-	-	-	-	-
2072	-	-	-	-	-	-
2073	-	-	-	-	-	-
2074	-	-	-	-	-	-
2075	-	-	-	-	-	-
Project Totals	1,112,263			3,843,346	3,843,346	-

RTEP Projected Rev. Req't. From Prior Year Template w/o Incentives	RTEP Projected Rev. Req't. From Prior Year Template with Incentives **
\$ 226,163	\$ 226,163
\$ 7,946	\$ 7,946
\$ 18,182	\$ 18,182
\$ 125,631	\$ 125,631
\$ 125,733	\$ 125,733
\$ 124,826	\$ 124,826
\$ 127,072	\$ 127,072

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

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

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

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

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

A. Base Plan Facilities

Facilities receiving incentives accepted by FERC in Docket No. [REDACTED]

(e.g. ER05-925-000)

Current Projected Year ARR	93,165
Current Projected Year ARR w/ Incentive	93,165
Current Projected Year Incentive ARR	-

Project Description:

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

Investment Year	Beginning Balance	Depreciation Expense	Ending Balance	RTEP Rev. Req't. w/o Incentives	RTEP Rev. Req't. with Incentives **	Incentive Rev. Requirement #
2013	818,037	-	818,037	98,785	98,785	-
2014	818,037	20,975	797,062	118,494	118,494	-
2015	797,062	20,975	776,087	115,961	115,961	-
2016	776,087	20,975	755,111	113,428	113,428	-
2017	755,111	20,975	734,136	110,895	110,895	-
2018	734,136	20,975	713,161	108,362	108,362	-
2019	713,161	20,975	692,185	105,829	105,829	-
2020	692,185	20,975	671,210	103,296	103,296	-
2021	671,210	20,975	650,235	100,763	100,763	-
2022	650,235	20,975	629,259	98,230	98,230	-
2023	629,259	20,975	608,284	95,697	95,697	-
2024	608,284	20,975	587,309	93,165	93,165	-
2025	587,309	20,975	566,333	90,632	90,632	-
2026	566,333	20,975	545,358	88,099	88,099	-
2027	545,358	20,975	524,383	85,566	85,566	-
2028	524,383	20,975	503,408	83,033	83,033	-
2029	503,408	20,975	482,432	80,500	80,500	-
2030	482,432	20,975	461,457	77,967	77,967	-
2031	461,457	20,975	440,482	75,434	75,434	-
2032	440,482	20,975	419,506	72,901	72,901	-
2033	419,506	20,975	398,531	70,368	70,368	-
2034	398,531	20,975	377,556	67,835	67,835	-
2035	377,556	20,975	356,580	65,302	65,302	-
2036	356,580	20,975	335,605	62,769	62,769	-
2037	335,605	20,975	314,630	60,236	60,236	-
2038	314,630	20,975	293,654	57,703	57,703	-
2039	293,654	20,975	272,679	55,170	55,170	-
2040	272,679	20,975	251,704	52,637	52,637	-
2041	251,704	20,975	230,728	50,104	50,104	-
2042	230,728	20,975	209,753	47,571	47,571	-
2043	209,753	20,975	188,778	45,038	45,038	-
2044	188,778	20,975	167,803	42,505	42,505	-
2045	167,803	20,975	146,827	39,972	39,972	-
2046	146,827	20,975	125,852	37,440	37,440	-
2047	125,852	20,975	104,877	34,907	34,907	-
2048	104,877	20,975	83,901	32,374	32,374	-
2049	83,901	20,975	62,926	29,841	29,841	-
2050	62,926	20,975	41,951	27,308	27,308	-
2051	41,951	20,975	20,975	24,775	24,775	-
2052	20,975	20,975	0	22,242	22,242	-
2053	0	0	-	0	0	-
2054	-	-	-	-	-	-
2055	-	-	-	-	-	-
2056	-	-	-	-	-	-
2057	-	-	-	-	-	-
2058	-	-	-	-	-	-
2059	-	-	-	-	-	-
2060	-	-	-	-	-	-
2061	-	-	-	-	-	-
2062	-	-	-	-	-	-
2063	-	-	-	-	-	-
2064	-	-	-	-	-	-
2065	-	-	-	-	-	-
2066	-	-	-	-	-	-
2067	-	-	-	-	-	-
2068	-	-	-	-	-	-
2069	-	-	-	-	-	-
2070	-	-	-	-	-	-
2071	-	-	-	-	-	-
2072	-	-	-	-	-	-
Project Totals		818,037		2,843,135	2,843,135	-

CUMULATIVE HISTORY OF PROJECTED ANNUAL REVENUE REQUIREMENTS:

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

RTEP Projected Rev. Req't. From Prior Year Template w/o Incentives	RTEP Projected Rev. Req't. From Prior Year Template with Incentives **
\$ -	\$ -
\$ 139,756	\$ 139,756
\$ 133,078	\$ 133,078
\$ 132,118	\$ 132,118
\$ 119,121	\$ 119,121
\$ 98,812	\$ 98,812
\$ 90,112	\$ 90,112
\$ 87,283	\$ 87,283
\$ 86,203	\$ 86,203
\$ 87,433	\$ 87,433

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

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

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

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

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

A. Base Plan Facilities

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

Current Projected Year ARR	408,437
Current Projected Year ARR w/ Incentive	408,437
Current Projected Year Incentive ARR	-

Project Description: RTEP ID: b1819 (Rebuild the Robinson Park-Sorneson 138 kV line corridor as a 345 kV double circuit line with one side operated at 345 kV and one side at 138 kV)

Details		2024				
Investment	3,315,854	Current Year				2024
Service Year (yyyy)	2016	ROE increase accepted by FERC (Basis Points)				-
Service Month (1-12)	12	FCR w/o incentives, less depreciation				12.08%
Useful life	39	FCR w/incentives approved for these facilities, less dep.				12.08%
CIAC (Yes or No)	No	Annual Depreciation Expense				85,022

Investment Year	Beginning Balance	Depreciation Expense	Ending Balance	RTEP Rev. Req't. w/o Incentives	RTEP Rev. Req't. with Incentives **	Incentive Rev. Requirement ##
2016	3,315,854	-	3,315,854	400,419	400,419	\$ -
2017	3,315,854	85,022	3,230,832	480,307	480,307	\$ -
2018	3,230,832	85,022	3,145,810	470,040	470,040	\$ -
2019	3,145,810	85,022	3,060,789	459,773	459,773	\$ -
2020	3,060,789	85,022	2,975,767	449,506	449,506	\$ -
2021	2,975,767	85,022	2,890,745	439,239	439,239	\$ -
2022	2,890,745	85,022	2,805,723	428,971	428,971	\$ -
2023	2,805,723	85,022	2,720,701	418,704	418,704	\$ -
2024	2,720,701	85,022	2,635,679	408,437	408,437	\$ -
2025	2,635,679	85,022	2,550,657	398,170	398,170	\$ -
2026	2,550,657	85,022	2,465,635	387,903	387,903	\$ -
2027	2,465,635	85,022	2,380,613	377,636	377,636	\$ -
2028	2,380,613	85,022	2,295,591	367,368	367,368	\$ -
2029	2,295,591	85,022	2,210,570	357,101	357,101	\$ -
2030	2,210,570	85,022	2,125,548	346,834	346,834	\$ -
2031	2,125,548	85,022	2,040,526	336,567	336,567	\$ -
2032	2,040,526	85,022	1,955,504	326,300	326,300	\$ -
2033	1,955,504	85,022	1,870,482	316,033	316,033	\$ -
2034	1,870,482	85,022	1,785,460	305,766	305,766	\$ -
2035	1,785,460	85,022	1,700,438	295,498	295,498	\$ -
2036	1,700,438	85,022	1,615,416	285,231	285,231	\$ -
2037	1,615,416	85,022	1,530,394	274,964	274,964	\$ -
2038	1,530,394	85,022	1,445,372	264,697	264,697	\$ -
2039	1,445,372	85,022	1,360,350	254,430	254,430	\$ -
2040	1,360,350	85,022	1,275,329	244,163	244,163	\$ -
2041	1,275,329	85,022	1,190,307	233,896	233,896	\$ -
2042	1,190,307	85,022	1,105,285	223,628	223,628	\$ -
2043	1,105,285	85,022	1,020,263	213,361	213,361	\$ -
2044	1,020,263	85,022	935,241	203,094	203,094	\$ -
2045	935,241	85,022	850,219	192,827	192,827	\$ -
2046	850,219	85,022	765,197	182,560	182,560	\$ -
2047	765,197	85,022	680,175	172,293	172,293	\$ -
2048	680,175	85,022	595,153	162,026	162,026	\$ -
2049	595,153	85,022	510,131	151,758	151,758	\$ -
2050	510,131	85,022	425,110	141,491	141,491	\$ -
2051	425,110	85,022	340,088	131,224	131,224	\$ -
2052	340,088	85,022	255,066	120,957	120,957	\$ -
2053	255,066	85,022	170,044	110,690	110,690	\$ -
2054	170,044	85,022	85,022	100,423	100,423	\$ -
2055	85,022	85,022	-	90,155	90,155	\$ -
2056	-	-	-	-	-	\$ -
2057	-	-	-	-	-	\$ -
2058	-	-	-	-	-	\$ -
2059	-	-	-	-	-	\$ -
2060	-	-	-	-	-	\$ -
2061	-	-	-	-	-	\$ -
2062	-	-	-	-	-	\$ -
2063	-	-	-	-	-	\$ -
2064	-	-	-	-	-	\$ -
2065	-	-	-	-	-	\$ -
2066	-	-	-	-	-	\$ -
2067	-	-	-	-	-	\$ -
2068	-	-	-	-	-	\$ -
2069	-	-	-	-	-	\$ -
2070	-	-	-	-	-	\$ -
2071	-	-	-	-	-	\$ -
2072	-	-	-	-	-	\$ -
2073	-	-	-	-	-	\$ -
2074	-	-	-	-	-	\$ -
2075	-	-	-	-	-	\$ -
Project Totals			3,315,854	11,524,438	11,524,438	-

CUMULATIVE HISTORY OF PROJECTED ANNUAL REVENUE REQUIREMENTS:

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

RTEP Projected Rev. Req't. From Prior Year Template w/o Incentives	RTEP Projected Rev. Req't. From Prior Year Template with Incentives **		
\$ 486,138	\$ 486,138		
\$ 574,408	\$ 574,408		
\$ 355,679	\$ 355,679		
\$ 367,592	\$ 367,592		
\$ 376,071	\$ 376,071		
\$ 373,465	\$ 373,465		
\$ 380,260	\$ 380,260		

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

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

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

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

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

A. Base Plan Facilities

Facilities receiving incentives accepted by FERC in Docket No. [REDACTED]

(e.g. ER05-925-000)

Current Projected Year ARR	85,586
Current Projected Year ARR w/ Incentive	85,586
Current Projected Year Incentive ARR	-

Project Description:

RTEP ID: b2831.1 (Upgrade Tanner Creek-Miami Fort 345kV circuit)

Details		Current Year	2024			
Investment	653,739					
Service Year (yyyy)	2019	ROE increase accepted by FERC (Basis Points)				
Service Month (1-12)	6	FCR w/o incentives, less depreciation			12.08%	
Useful life	39	FCR w/incentives approved for these facilities, less dep.			12.08%	
CIAC (Yes or No)	No	Annual Depreciation Expense			16,763	

Investment Year	Beginning Balance	Depreciation Expense	Ending Balance	RTEP Rev. Req't. w/o Incentives	RTEP Rev. Req't. with Incentives **	Incentive Rev. Requirement ##
2019	653,739	8,381	645,358	86,820	86,820	\$ -
2020	645,358	16,763	628,595	93,683	93,683	\$ -
2021	628,595	16,763	611,833	91,659	91,659	\$ -
2022	611,833	16,763	595,070	89,635	89,635	\$ -
2023	595,070	16,763	578,308	87,610	87,610	\$ -
2024	578,308	16,763	561,545	85,586	85,586	\$ -
2025	561,545	16,763	544,783	83,562	83,562	\$ -
2026	544,783	16,763	528,020	81,538	81,538	\$ -
2027	528,020	16,763	511,258	79,514	79,514	\$ -
2028	511,258	16,763	494,495	77,489	77,489	\$ -
2029	494,495	16,763	477,733	75,465	75,465	\$ -
2030	477,733	16,763	460,970	73,441	73,441	\$ -
2031	460,970	16,763	444,207	71,417	71,417	\$ -
2032	444,207	16,763	427,445	69,392	69,392	\$ -
2033	427,445	16,763	410,682	67,368	67,368	\$ -
2034	410,682	16,763	393,920	65,344	65,344	\$ -
2035	393,920	16,763	377,157	63,320	63,320	\$ -
2036	377,157	16,763	360,395	61,296	61,296	\$ -
2037	360,395	16,763	343,632	59,271	59,271	\$ -
2038	343,632	16,763	326,870	57,247	57,247	\$ -
2039	326,870	16,763	310,107	55,223	55,223	\$ -
2040	310,107	16,763	293,345	53,199	53,199	\$ -
2041	293,345	16,763	276,582	51,174	51,174	\$ -
2042	276,582	16,763	259,819	49,150	49,150	\$ -
2043	259,819	16,763	243,057	47,126	47,126	\$ -
2044	243,057	16,763	226,294	45,102	45,102	\$ -
2045	226,294	16,763	209,532	43,077	43,077	\$ -
2046	209,532	16,763	192,769	41,053	41,053	\$ -
2047	192,769	16,763	176,007	39,029	39,029	\$ -
2048	176,007	16,763	159,244	37,005	37,005	\$ -
2049	159,244	16,763	142,482	34,981	34,981	\$ -
2050	142,482	16,763	125,719	32,956	32,956	\$ -
2051	125,719	16,763	108,957	30,932	30,932	\$ -
2052	108,957	16,763	92,194	28,908	28,908	\$ -
2053	92,194	16,763	75,431	26,884	26,884	\$ -
2054	75,431	16,763	58,669	24,859	24,859	\$ -
2055	58,669	16,763	41,906	22,835	22,835	\$ -
2056	41,906	16,763	25,144	20,811	20,811	\$ -
2057	25,144	16,763	8,381	18,787	18,787	\$ -
2058	8,381	8,381	-	8,887	8,887	\$ -
2059	-	-	-	-	-	\$ -
2060	-	-	-	-	-	\$ -
2061	-	-	-	-	-	\$ -
2062	-	-	-	-	-	\$ -
2063	-	-	-	-	-	\$ -
2064	-	-	-	-	-	\$ -
2065	-	-	-	-	-	\$ -
2066	-	-	-	-	-	\$ -
2067	-	-	-	-	-	\$ -
2068	-	-	-	-	-	\$ -
2069	-	-	-	-	-	\$ -
2070	-	-	-	-	-	\$ -
2071	-	-	-	-	-	\$ -
2072	-	-	-	-	-	\$ -
2073	-	-	-	-	-	\$ -
2074	-	-	-	-	-	\$ -
2075	-	-	-	-	-	\$ -
2076	-	-	-	-	-	\$ -
2077	-	-	-	-	-	\$ -
2078	-	-	-	-	-	\$ -
Project Totals		653,739		2,232,635	2,232,635	-

CUMULATIVE HISTORY OF PROJECTED ANNUAL REVENUE REQUIREMENTS:

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

RTEP Projected Rev. Req't. From Prior Year Template w/o Incentives	RTEP Projected Rev. Req't. From Prior Year Template with Incentives **			
\$ 67,813	\$ 67,813			
\$ 66,522	\$ 66,522			
\$ 77,582	\$ 77,582			
\$ 79,219	\$ 79,219			

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

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

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

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

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

A. Base Plan Facilities

Facilities receiving incentives accepted by FERC in Docket No. [REDACTED]

(e.g. ER05-925-000)

Current Projected Year ARR	985,596
Current Projected Year ARR w/ Incentive	985,596
Current Projected Year Incentive ARR	-

Project Description:

RTEP ID: b2777 (Reconductor the entire Dequino - Eugene 345 kV circuit #1)

Details		Current Year	2024			
Investment	7,055,539					
Service Year (yyyy)	2022	ROE increase accepted by FERC (Basis Points)				
Service Month (1-12)	4	FCR w/o incentives, less depreciation			12.08%	
Useful life	39	FCR w/incentives approved for these facilities, less dep.			12.08%	
CIAC (Yes or No)	No	Annual Depreciation Expense			180,911	

Investment Year	Beginning Balance	Depreciation Expense	Ending Balance	RTEP Rev. Req't. w/o Incentives	RTEP Rev. Req't. with Incentives **	Incentive Rev. Requirement ##
2022	7,055,539	120,607	6,934,931	965,344	965,344	\$ -
2023	6,934,931	180,911	6,754,020	1,007,442	1,007,442	\$ -
2024	6,754,020	180,911	6,573,109	985,596	985,596	\$ -
2025	6,573,109	180,911	6,392,197	963,749	963,749	\$ -
2026	6,392,197	180,911	6,211,286	941,902	941,902	\$ -
2027	6,211,286	180,911	6,030,375	920,056	920,056	\$ -
2028	6,030,375	180,911	5,849,464	898,209	898,209	\$ -
2029	5,849,464	180,911	5,668,552	876,362	876,362	\$ -
2030	5,668,552	180,911	5,487,641	854,516	854,516	\$ -
2031	5,487,641	180,911	5,306,730	832,669	832,669	\$ -
2032	5,306,730	180,911	5,125,819	810,823	810,823	\$ -
2033	5,125,819	180,911	4,944,907	788,976	788,976	\$ -
2034	4,944,907	180,911	4,763,996	767,129	767,129	\$ -
2035	4,763,996	180,911	4,583,085	745,283	745,283	\$ -
2036	4,583,085	180,911	4,402,174	723,436	723,436	\$ -
2037	4,402,174	180,911	4,221,262	701,589	701,589	\$ -
2038	4,221,262	180,911	4,040,351	679,743	679,743	\$ -
2039	4,040,351	180,911	3,859,440	657,896	657,896	\$ -
2040	3,859,440	180,911	3,678,529	636,049	636,049	\$ -
2041	3,678,529	180,911	3,497,617	614,203	614,203	\$ -
2042	3,497,617	180,911	3,316,706	592,356	592,356	\$ -
2043	3,316,706	180,911	3,135,795	570,510	570,510	\$ -
2044	3,135,795	180,911	2,954,884	548,663	548,663	\$ -
2045	2,954,884	180,911	2,773,972	526,816	526,816	\$ -
2046	2,773,972	180,911	2,593,061	504,970	504,970	\$ -
2047	2,593,061	180,911	2,412,150	483,123	483,123	\$ -
2048	2,412,150	180,911	2,231,239	461,276	461,276	\$ -
2049	2,231,239	180,911	2,050,327	439,430	439,430	\$ -
2050	2,050,327	180,911	1,869,416	417,583	417,583	\$ -
2051	1,869,416	180,911	1,688,505	395,736	395,736	\$ -
2052	1,688,505	180,911	1,507,594	373,890	373,890	\$ -
2053	1,507,594	180,911	1,326,682	352,043	352,043	\$ -
2054	1,326,682	180,911	1,145,771	330,197	330,197	\$ -
2055	1,145,771	180,911	964,860	308,350	308,350	\$ -
2056	964,860	180,911	783,949	286,503	286,503	\$ -
2057	783,949	180,911	603,037	264,657	264,657	\$ -
2058	603,037	180,911	422,126	242,810	242,810	\$ -
2059	422,126	180,911	241,215	220,963	220,963	\$ -
2060	241,215	180,911	60,304	199,117	199,117	\$ -
2061	60,304	60,304	-	63,945	63,945	\$ -
2062	-	-	-	-	-	\$ -
2063	-	-	-	-	-	\$ -
2064	-	-	-	-	-	\$ -
2065	-	-	-	-	-	\$ -
2066	-	-	-	-	-	\$ -
2067	-	-	-	-	-	\$ -
2068	-	-	-	-	-	\$ -
2069	-	-	-	-	-	\$ -
2070	-	-	-	-	-	\$ -
2071	-	-	-	-	-	\$ -
2072	-	-	-	-	-	\$ -
2073	-	-	-	-	-	\$ -
2074	-	-	-	-	-	\$ -
2075	-	-	-	-	-	\$ -
2076	-	-	-	-	-	\$ -
2077	-	-	-	-	-	\$ -
2078	-	-	-	-	-	\$ -
2079	-	-	-	-	-	\$ -
2080	-	-	-	-	-	\$ -
2081	-	-	-	-	-	\$ -
Project Totals	7,055,539		23,953,910	23,953,910		-

CUMULATIVE HISTORY OF PROJECTED ANNUAL REVENUE REQUIREMENTS:

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

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

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

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

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

AEP East Companies
Cost of Service Formula Rate Using 2024 FF1 Balances
Worksheet L Reserved for Future Use
Indiana Michigan 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
Indiana Michigan Power Company

Line No	Month (a)	Average Balance of Common Equity				Average Balance of Common Equity (f)=(b)-(c)-(d)-(e)
		Proprietary Capital (b)	Less: Preferred Stock (c)	Less Undistributed Sub Earnings (Acct 216.1) (d)	Less AOCI (Acct 219.1) (e)	
(Note A)		(FF1 112.16)	(FF1 250-251)	(FF1 112.12)	(FF1 112.15)	
1	December Prior to Rate Year	3,148,429,800		(2,703,331)	(2,655,504)	3,153,788,636
2	January	3,177,163,471		(2,690,356)	(2,589,463)	3,182,443,290
3	February	3,167,837,666		(2,680,271)	(2,523,422)	3,173,041,358
4	March	3,196,797,514		(2,664,162)	(2,457,381)	3,201,919,057
5	April	3,221,299,366		(2,644,538)	(2,391,340)	3,226,335,244
6	May	3,214,063,092		(2,639,139)	(2,325,299)	3,219,027,529
7	June	3,242,383,582		(2,612,527)	(2,259,258)	3,247,255,367
8	July	3,271,990,881		(2,579,968)	(2,193,217)	3,276,764,065
9	August	3,266,966,618		(2,539,535)	(2,127,176)	3,271,633,330
10	September	3,288,479,034		(2,471,753)	(2,061,135)	3,293,011,922
11	October	3,313,094,882		(2,431,196)	(1,995,094)	3,317,521,172
12	November	3,301,079,921		(2,510,580)	(1,929,053)	3,305,519,554
13	December of Rate Year	3,324,716,793		(2,416,144)	(1,863,012)	3,328,995,949
14	Average of the 13 Monthly Balances	3,241,100,201	-	(2,583,346)	(2,259,258)	3,245,942,806

Line No	Month (a)	Average Balance of Long Term Debt					Gross Proceeds Outstanding Long-Term Debt (g)=(b)-(c)+(d)+(e)-(f)
		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)	
(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	-	-	-	3,073,585,133	-	3,073,585,133
16	January	-	-	-	3,062,097,661	-	3,062,097,661
17	February	-	-	-	3,062,097,661	-	3,062,097,661
18	March	-	-	-	3,062,097,661	-	3,062,097,661
19	April	-	-	-	3,062,097,661	-	3,062,097,661
20	May	-	-	-	3,062,097,661	-	3,062,097,661
21	June	-	-	-	3,062,097,661	-	3,062,097,661
22	July	-	-	-	3,062,097,661	-	3,062,097,661
23	August	-	-	-	3,062,097,661	-	3,062,097,661
24	September	-	-	-	3,062,097,661	-	3,062,097,661
25	October	-	-	-	3,062,097,661	-	3,062,097,661
26	November	-	-	-	3,062,097,661	-	3,062,097,661
27	December of Rate Year	-	-	-	3,062,097,661	-	3,062,097,661
28	Average of the 13 Monthly Balances	-	-	-	3,062,981,313	-	3,062,981,313

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 2024						
30	Interest on Long Term Debt - Accts 221 - 224 (256-257.33.i)			135,780,251			
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.			2,028,252			
32	Plus: Allowed Hedge Recovery From Ln 55 below.			2,028,252			
33	Amort of Debt Discount & Expense - Acct 428 (117.63.c)			1,879,797			
34	Amort of Loss on Reacquired Debt - Acct 428.1 (117.64.c)			1,101,898			
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)			138,761,947			
38	Average Cost of Debt for 2024 (Ln 37/ Ln 28 (g))			4.53%			

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 2024	Less Excludable Amounts (See NOTE on Line 39)	Net Includable Hedge Amount	Amortization Period		
					Remaining Unamortized Balance	Beginning	Ending
40	Senior Unsecured Notes - Series F	-	-	-	-	November 2004	November 2014
41	Senior Unsecured Notes - Series G	-	-	-	-	12/07/05	11/30/15
42	Senior Unsecured Notes - Series H	421,763	-	421,763	5,957,082	11/14/06	02/28/37
43	Senior Unsecured Notes - Series J	1,606,489	-	1,606,489	334,685	03/15/13	03/15/23
44							
45							
46							
47							
48							
49					6,291,767		
50	Total Hedge Amortization	2,028,252	-				
51	Hedge Gain or Loss Prior to Application of Recovery Limit (Sum of Lines 40 to 48)			2,028,252			
52	Total Average Capital Structure Balance for 2024 (TCOS, Ln 157)			6,308,924,118			
53	Financial Hedge Recovery Limit - Five Basis Points of Total Capital			0.0005			
54	Limit of Recoverable Amount			3,154,462			
55	Recoverable Hedge Amortization (Lesser of Ln 51 or Ln 54)			2,028,252			

Development of Cost of Preferred Stock

	Preferred Stock	Average
56	0% Series - 0 - Dividend Rate (p. 250-251)	0.000%
57	0% Series - 0 - Par Value (p. 250-251)	\$ - \$ -
58	0% Series - 0 - Shares O/S (p.250-251)	-
59	0% Series - 0 - Monetary Value (Ln 57 * Ln 58)	-
60	0% Series - 0 - Dividend Amount (Ln 56 * Ln 59)	-
61	0% Series - 0 - Dividend Rate (p. 250-251)	0.000%
62	0% Series - 0 - Par Value (p. 250-251)	\$ - \$ -
63	0% Series - 0 - Shares O/S (p.250-251)	-
64	0% Series - 0 - Monetary Value (Ln 62 * Ln 63)	-
65	0% Series - 0 - Dividend Amount (Ln 61 * Ln 64)	-
66	0% Series - 0 - Dividend Rate (p. 250-251)	0.000%

67 0% Series - 0 - Par Value (p. 250-251)
 68 0% Series - 0 - Shares O/S (p.250-251)
 69 0% Series - 0 - Monetary Value (Ln 67 * Ln 68)
 70 0% Series - 0 - Dividend Amount (Ln 66 * Ln 69)

71 **Balance of Preferred Stock (Lns 59, 64, 69)**
 72 **Dividends on Preferred Stock (Lns 60, 65, 70)**
 73 **Average Cost of Preferred Stock (Ln 72/71)**

\$	-	\$	-
	-	-	-
	-	-	-
	-	-	-
	-	-	-
	-	-	-
	-	-	-
	0.00%	0.00%	0.00%

- Year End Total Agrees to FF1 p.112, Ln 3, col (c) & (d)

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

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

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	
Line	Date	Property Description	Function (T) or (G) T = Transmission G = General	Basis	Proceeds	(Gain) / Loss	Functional Allocator	Functionalized Proceeds (Gain) / Loss	FERC Account
1						-	0.000%	-	
2						-	0.000%	-	
3						-	0.000%	-	
4				Net (Gain) or Loss for 2024		-		-	

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
Indiana Michigan Power Company

1 Total AEP East Operating Company PBOP Settlement Amount 52,287,952

Allocation of PBOP Settlement Amount for 2024

Line#	Company	Total Company Amount						
		Actual Expense (Including AEPSC Billed OPEB)	Ratio of Company Actual to Total	Allocation of PBOP Recovery Allowance	Labor Allocator for 2024	Actual Expense	Allowable Expense	One Year Functional Expense (Over)/Under
		(A) (Line 14)	(B)=(A)/Total (A)	(C)=(B) * 52287952	(D)	(E)=(A) * (D)	(F)=(C) * (D)	(G)=(E) - (F)
2	APCo	(28,089,629)	35.97%	18,808,544	10.718%	(3,010,598)	2,015,867	(5,026,465)
3	I&M	(20,588,133)	26.36%	13,785,615	5.114%	(1,052,792)	704,939	(1,757,731)
4	KPCo	(6,450,810)	8.26%	4,319,400	9.832%	(634,267)	424,699	(1,058,966)
5	KNGP	(701,395)	0.90%	469,647	8.999%	(63,117)	42,262	(105,379)
6	OPCo	(20,853,938)	26.71%	13,963,596	12.482%	(2,603,050)	1,742,977	(4,346,028)
7	WPCo	(1,405,562)	1.80%	941,150	2.884%	(40,540)	27,145	(67,686)
8	Sum of Lines 2 to 7	(78,089,465)		52,287,952		(7,404,364)	4,957,891	(12,362,255)

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	(9,880,000)	(8,311,000)	(1,994,000)	(231,000)	(7,132,000)	(946,000)	(28,494,000)
10 Additional PBOP Ledger Entries (from Company Records)	672,186	2,408,275	581,811	0	0	(539,281)	
11 Medicare Subsidy	-	-	-	-	-	-	-
12 Net Company Expense (Ln 9 + Ln 10 + Ln 11)	(9,207,814)	(5,902,725)	(1,412,189)	(231,000)	(7,132,000)	(1,485,281)	(25,371,008)
13 PBOP Expenses From AEP Service Corporation (from Company Records)	(6,901,942)	(3,895,823)	(1,524,371)	(204,837)	(5,390,620)	(259,814)	(18,177,406)
14 Company PBOP Expense (Ln 12 + Ln 13)	(16,109,756)	(9,798,548)	(2,936,560)	(435,837)	(12,522,620)	(1,745,095)	(43,548,414)

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 allowance 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 1/1/2020
FOR MULTIPLE JURISDICTION COMPANIES
Appalachian Power Company

	VIRGINIA				WEST VIRGINIA			FERC WHOLESALE			FERC KINGSFORT			COMPANY
	(1) PLANT ACCT.	VA SCC RATES	ALLOCATION FACTOR (5)	WTD AVG. DEPREC. RATE	(2) PSC OF WV APPROVED RATES	ALLOCATION FACTOR (5)	WTD AVG. DEPREC. RATE	(3) FERC RATES	ALLOCATION FACTOR (5)	WTD AVG. DEPREC. RATE	(4) 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				14.22%	1.000000	14.22%							14.22%
Structures & Improvements	352.0	1.99%	0.494821	0.98%	1.62%	0.411083	0.67%	2.19%	0.036533	0.08%	2.19%	0.057563	0.13%	1.86%
Station Equipment	353.0	2.70%	0.494821	1.34%	2.37%	0.411083	0.97%	2.19%	0.036533	0.08%	2.19%	0.057563	0.13%	2.52%
Towers & Fixtures	354.0	1.64%	0.494821	0.81%	1.59%	0.411083	0.65%	2.19%	0.036533	0.08%	2.19%	0.057563	0.13%	1.67%
Poles & Fixtures	355.0	3.46%	0.494821	1.71%	2.71%	0.411083	1.11%	2.19%	0.036533	0.08%	2.19%	0.057563	0.13%	3.03%
Overhead Conductor	356.0	1.65%	0.494821	0.82%	1.53%	0.411083	0.63%	2.19%	0.036533	0.08%	2.19%	0.057563	0.13%	1.66%
Underground Conduit	357.0	2.49%	0.494821	1.23%	3.71%	0.411083	1.53%	2.19%	0.036533	0.08%	2.19%	0.057563	0.13%	2.97%
Underground Conductors	358.0	4.72%	0.494821	2.34%	5.24%	0.411083	2.15%	2.19%	0.036533	0.08%	2.19%	0.057563	0.13%	4.70%
GENERAL PLANT														
Structures & Improvements	390.0	1.89%	0.523756	0.99%	1.91%	0.425941	0.81%	3.43%	0.019295	0.07%	3.43%	0.031009	0.11%	1.98%
Office Furniture & Equipment	391.0	3.21%	0.523756	1.68%	3.17%	0.425941	1.35%	3.43%	0.019295	0.07%	3.43%	0.031009	0.11%	3.21%
Transportation Equipment	392.0	3.46%	0.523756	1.81%	3.40%	0.425941	1.45%	3.43%	0.019295	0.07%	3.43%	0.031009	0.11%	3.44%
Stores Equipment	393.0	1.78%	0.523756	0.93%	1.80%	0.425941	0.77%	3.43%	0.019295	0.07%	3.43%	0.031009	0.11%	1.88%
Tools Shop & Garage Equipment	394.0	2.59%	0.523756	1.36%	2.57%	0.425941	1.09%	3.43%	0.019295	0.07%	3.43%	0.031009	0.11%	2.63%
Laboratory Equipment	395.0	3.87%	0.523756	2.03%	4.01%	0.425941	1.71%	3.43%	0.019295	0.07%	3.43%	0.031009	0.11%	3.92%
Power Operated Equipment	396.0	0.00%	0.523756	0.00%	3.90%	0.425941	1.66%	3.43%	0.019295	0.07%	3.43%	0.031009	0.11%	1.84%
Communication Equipment	397.0	5.05%	0.523756	2.64%	4.98%	0.425941	2.12%	3.43%	0.019295	0.07%	3.43%	0.031009	0.11%	4.94%
Miscellaneous Equipment	398.0	2.67%	0.523756	1.40%	2.70%	0.425941	1.15%	3.43%	0.019295	0.07%	3.43%	0.031009	0.11%	2.73%

(1) As approved in VA Case No. PUE 2020-00015 on Nov. 24, 2020
Depreciation rates were made effective on January 1, 2020.

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

(2) Approved by PSC of WV Order dated 2/27/2019 in
Case No. 18-0645-E-D effective 03/06/2019.

(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) Distribution Plant (recorded by state) is assigned only to
jurisdictions within each state.

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 jurisdiction's 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 MARCH 11, 2020
FOR MULTIPLE JURISDICTION COMPANIES
INDIANA MICHIGAN POWER COMPANY

	INDIANA				MICHIGAN AND FERC			COMPANY
	(1) PLANT ACCT.	IURC RATES	ALLOCATION FACTOR (4)	WTD AVG. DEPREC. RATE	(2) MPSC APPROVED RATES	ALLOCATION FACTOR (4)	WTD AVG. DEPREC. RATE	WTD AVG. DEPREC. RATE
TRANSMISSION PLANT								
Land Improvements	350.1	1.6600%	0.662335	1.0995%	1.6200%	0.337665	0.5470%	1.65%
Structures & Improvements	352.0	1.7700%	0.662335	1.1723%	1.7400%	0.337665	0.5875%	1.76%
Station Equipment	353.0	2.4300%	0.662335	1.6095%	2.4100%	0.337665	0.8138%	2.42%
Towers & Fixtures	354.0	2.5700%	0.662335	1.7022%	2.4500%	0.337665	0.8273%	2.53%
Poles & Fixtures	355.0	3.1900%	0.662335	2.1128%	3.1700%	0.337665	1.0704%	3.18%
Overhead Conductors	356.0	2.3500%	0.662335	1.5565%	2.2800%	0.337665	0.7699%	2.33%
Underground Conduit	357.0	2.3000%	0.662335	1.5234%	2.2100%	0.337665	0.7462%	2.27%
Underground Conductors	358.0	1.9300%	0.662335	1.2783%	1.9000%	0.337665	0.6416%	1.92%
Trails & Roads	359.0	1.6100%	0.662335	1.0664%	1.5900%	0.337665	0.5369%	1.60%
GENERAL PLANT								
	390.0	2.0800%	0.681868	1.4183%	2.0800%	0.318132	0.6617%	2.08%
	391.0	4.7900%	0.681868	3.2661%	4.8400%	0.318132	1.5398%	4.81%
\$0 at Dec 2018 - use old rate	392.0	4.6400%	0.681868	3.1639%	4.6800%	0.318132	1.4889%	4.65%
	393.0	7.3500%	0.681868	5.0117%	7.3800%	0.318132	2.3478%	7.36%
	394.0	6.9900%	0.681868	4.7663%	7.0700%	0.318132	2.2492%	7.02%
	395.0	5.4100%	0.681868	3.6889%	5.4600%	0.318132	1.7370%	5.43%
	396.0	4.8100%	0.681868	3.2798%	4.9000%	0.318132	1.5588%	4.84%
	397.0	3.9100%	0.681868	2.6661%	3.9300%	0.318132	1.2503%	3.92%
	398.0	3.3200%	0.681868	2.2638%	3.3500%	0.318132	1.0657%	3.33%

(1) As approved in Indiana Cause No. 45235 effective March 11, 2020.

(2) As approved in Michigan Case No. U-20359 effective February 1, 2020.

(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 jurisdiction's rate is multiplied by an allocation factor, and the product for each jurisdiction is added with the other jurisdictions to derive the composite rate. 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
<i>TRANSMISSION PLANT</i>		
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.
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Note 2: Kingsport Power Company does not have investment in plant accounts 357 or 358. Therefore, there are no depreciation rates approved

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
<i>TRANSMISSION PLANT</i>		
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 4/1/2012
FOR SINGLE JURISDICTION COMPANIES
OHIO POWER COMPANY**

	PLANT ACCT.	RATES Note 1
<i>TRANSMISSION PLANT</i>		
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 69KV	356.0	1.91%
Overhead Conductor & Devices MSP	356.0	1.91%
Overhead Conductor & Devices 138KV	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 3/1/2019
FOR SINGLE JURISDICTION COMPANIES
WHEELING POWER COMPANY**

	PLANT ACCT.	RATES Note 1
<i>TRANSMISSION PLANT</i>		
Structures & Improvements	352.0	1.15%
Station Equipment	353.0	2.22%
Towers & Fixtures	354.0	2.65%
Poles & Fixtures	355.0	2.41%
Overhead Conductors	356.0	1.32%
Underground Conduit	351.0	9.94%
Underground Conductors	351.0	13.98%
Trails & Roads	359.0	-
<i>GENERAL PLANT</i>		
Structures & Improvements	390.0	1.08%
Office Furniture & Equipment	391.0	2.13%
Stores Equipment	393.0	1.78%
Tools Shop & Garage Equipment	394.0	1.65%
Communication Equipment	397.0	5.09%
Miscellaneous Equipment	398.0	2.76%

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 2022 Available May 25, 2023 \$176,154,020	-	2022 Forecasted Revenue Requirement For Year 2022 \$169,732,064	=	True-up Adjustment - Over (Under) Recovery (\$6,421,956)
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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
		0.4240%				
An over or under collection will be recovered prorata over 2022, held for 2023 and returned prorata over 2024						
Calculation of Interest				Monthly		
January	Year 2022	(535,163)	0.4240%	12	27,229	562,392
February	Year 2022	(535,163)	0.4240%	11	24,960	560,123
March	Year 2022	(535,163)	0.4240%	10	22,691	557,854
April	Year 2022	(535,163)	0.4240%	9	20,422	555,585
May	Year 2022	(535,163)	0.4240%	8	18,153	553,316
June	Year 2022	(535,163)	0.4240%	7	15,884	551,047
July	Year 2022	(535,163)	0.4240%	6	13,615	548,778
August	Year 2022	(535,163)	0.4240%	5	11,345	546,508
September	Year 2022	(535,163)	0.4240%	4	9,076	544,239
October	Year 2022	(535,163)	0.4240%	3	6,807	541,970
November	Year 2022	(535,163)	0.4240%	2	4,538	539,701
December	Year 2022	(535,163)	0.4240%	1	2,269	537,432
					176,989	6,598,945
January through December	Year 2023	6,598,945	0.4240%	12	335,754	6,934,699
Over (Under) Recovery Plus Interest Amortized and Recovered Over 12 Months				Monthly		
January	Year 2024	(6,934,699)	0.4240%		29,403	(593,942)
February	Year 2024	(6,370,161)	0.4240%		27,009	(593,942)
March	Year 2024	(5,803,228)	0.4240%		24,606	(593,942)
April	Year 2024	(5,233,892)	0.4240%		22,192	(593,942)
May	Year 2024	(4,662,142)	0.4240%		19,767	(593,942)
June	Year 2024	(4,087,968)	0.4240%		17,333	(593,942)
July	Year 2024	(3,511,359)	0.4240%		14,888	(593,942)
August	Year 2024	(2,932,305)	0.4240%		12,433	(593,942)
September	Year 2024	(2,350,796)	0.4240%		9,967	(593,942)
October	Year 2024	(1,766,822)	0.4240%		7,491	(593,942)
November	Year 2024	(1,180,371)	0.4240%		5,005	(593,942)
December	Year 2024	(591,434)	0.4240%		2,508	(593,942)
					192,603	0
True-Up Adjustment with Interest						7,127,302
Less Over (Under) Recovery						(6,421,956)
Total Interest						705,346

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 true-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 2022 Available May 25, 2023 <hr/> \$5,720,392	-	2022 Forecasted Revenue Requirement For Year 2022 <hr/> \$5,322,411	=	True-up Adjustment - Over (Under) Recovery <hr/> (\$397,981)
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Interest Rate on Amount of Refunds or Surcharge from 35.19a	Over (Under) Recovery Plus Interest	Average Monthly Interest Rate	Months	Calculated Interest	Amortization	Surcharge (Refund) Owed
		0.4240%				

An over or under collection will be recovered prorata over 2022, held for 2023 and returned prorata over 2024

<u>Calculation of Interest</u>				<u>Monthly</u>		
January	Year 2022	(33,165)	0.4240%	12	1,687	34,853
February	Year 2022	(33,165)	0.4240%	11	1,547	34,712
March	Year 2022	(33,165)	0.4240%	10	1,406	34,571
April	Year 2022	(33,165)	0.4240%	9	1,266	34,431
May	Year 2022	(33,165)	0.4240%	8	1,125	34,290
June	Year 2022	(33,165)	0.4240%	7	984	34,149
July	Year 2022	(33,165)	0.4240%	6	844	34,009
August	Year 2022	(33,165)	0.4240%	5	703	33,868
September	Year 2022	(33,165)	0.4240%	4	562	33,728
October	Year 2022	(33,165)	0.4240%	3	422	33,587
November	Year 2022	(33,165)	0.4240%	2	281	33,446
December	Year 2022	(33,165)	0.4240%	1	141	33,306
					10,968	408,949
				Annual		
January through December	Year 2023	408,949	0.4240%	12	20,807	429,757

<u>Over (Under) Recovery Plus Interest Amortized and Recovered Over 12 Months</u>				<u>Monthly</u>			
January	Year 2024	(429,757)	0.4240%		1,822	(36,808)	394,771
February	Year 2024	(394,771)	0.4240%		1,674	(36,808)	359,637
March	Year 2024	(359,637)	0.4240%		1,525	(36,808)	324,354
April	Year 2024	(324,354)	0.4240%		1,375	(36,808)	288,922
May	Year 2024	(288,922)	0.4240%		1,225	(36,808)	253,339
June	Year 2024	(253,339)	0.4240%		1,074	(36,808)	217,606
July	Year 2024	(217,606)	0.4240%		923	(36,808)	181,721
August	Year 2024	(181,721)	0.4240%		770	(36,808)	145,683
September	Year 2024	(145,683)	0.4240%		618	(36,808)	109,493
October	Year 2024	(109,493)	0.4240%		464	(36,808)	73,150
November	Year 2024	(73,150)	0.4240%		310	(36,808)	36,652
December	Year 2024	(36,652)	0.4240%		155	(36,808)	-
					11,936		

True-Up Adjustment with Interest	441,693
Less Over (Under) Recovery	(397,981)
Total Interest	43,712

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 true-up through August 31 of the following

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

Reconciliation Revenue Requirement For Year 2022 Available May 25, 2023 <hr/> \$302,633	-	2022 Collections <hr/> \$469,022	=	True-up Adjustment - Over (Under) Recovery <hr/> \$166,388
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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
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An over or under collection will be recovered prorata over 2022, held for 2023 and returned prorata over 2024

<u>Calculation of Interest</u>				<u>Monthly</u>		
January	Year 2022	13,866	0.4240%	12	(705)	(14,571)
February	Year 2022	13,866	0.4240%	11	(647)	(14,512)
March	Year 2022	13,866	0.4240%	10	(588)	(14,454)
April	Year 2022	13,866	0.4240%	9	(529)	(14,395)
May	Year 2022	13,866	0.4240%	8	(470)	(14,336)
June	Year 2022	13,866	0.4240%	7	(412)	(14,277)
July	Year 2022	13,866	0.4240%	6	(353)	(14,218)
August	Year 2022	13,866	0.4240%	5	(294)	(14,160)
September	Year 2022	13,866	0.4240%	4	(235)	(14,101)
October	Year 2022	13,866	0.4240%	3	(176)	(14,042)
November	Year 2022	13,866	0.4240%	2	(118)	(13,983)
December	Year 2022	13,866	0.4240%	1	(59)	(13,924)
					(4,586)	(170,974)

<u>Over (Under) Recovery Plus Interest Amortized and Recovered Over 12 Months</u>				<u>Annual</u>		
January through December	Year 2023	(170,974)	0.4240%	12	(8,699)	(179,673)

<u>Over (Under) Recovery Plus Interest Amortized and Recovered Over 12 Months</u>				<u>Monthly</u>		
January	Year 2024	179,673	0.4240%	(762)	15,389	(165,046)
February	Year 2024	165,046	0.4240%	(700)	15,389	(150,358)
March	Year 2024	150,358	0.4240%	(638)	15,389	(135,607)
April	Year 2024	135,607	0.4240%	(575)	15,389	(120,793)
May	Year 2024	120,793	0.4240%	(512)	15,389	(105,916)
June	Year 2024	105,916	0.4240%	(449)	15,389	(90,977)
July	Year 2024	90,977	0.4240%	(386)	15,389	(75,974)
August	Year 2024	75,974	0.4240%	(322)	15,389	(60,908)
September	Year 2024	60,908	0.4240%	(258)	15,389	(45,777)
October	Year 2024	45,777	0.4240%	(194)	15,389	(30,583)
November	Year 2024	30,583	0.4240%	(130)	15,389	(15,324)
December	Year 2024	15,324	0.4240%	(65)	15,389	(0)
					(4,990)	

True-Up Adjustment with Interest	(184,663)
Less Over (Under) Recovery	166,388
Total Interest	(18,275)

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 true-up through August 31 of the following year.