ALSTON&BIRD LLP
The Atlantic Building
950 F Street, NW
Washington, DC 20004-1404

202-239-3300
Fax: 202-239-3333
www.alston.com

May 2, 2011

The Honorable Kimberly D. Bose
Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, D.C. 20426

Re: ***American Transmission Systems, Incorporated***
Informational Filing
2011 Transmission Formula Rate Annual Update
Docket No. ER____________

Dear Secretary Bose:

American Transmission Systems, Incorporated ("ATSI") hereby submits for informational purposes only its 2011 Transmission Formula Rate Annual Update as required under Attachment H-21B (Formula Rate Implementation Protocols) (the "ATSI Protocols") under the Open Access Transmission Tariff of PJM Interconnection, L.L.C. ("PJM"). As provided in Section 1.b of the ATSI Protocols, this 2011 Annual Update is an Informational Filing and therefore does not require any Commission action.

Description of Filing

On December 17, 2009, the Commission approved ATSI's request to integrate into PJM effective June 1, 2011.[1] And, ATSI is on schedule to meet that June 1, 2011 integration date. As part of ATSI's integration into PJM, ATSI filed its transmission formula rate with the Commission on February 1, 2011. It is designated as Attachment H-21 under the PJM OATT, and is pending in Docket No. ER11-2814, *et al*.

Pursuant to the ATSI Protocols, on or before May 1 of each year,[2] ATSI is required to recalculate its annual transmission revenue requirements, producing the "Annual Update" for the upcoming rate year. ATSI is required to submit the Annual

---

[1] *American Transmission Systems, Inc.*, 129 FERC ¶ 61,249 (2009).

[2] ATSI is submitting this filing on Monday, May 2, 2011 because Section 1.c. of the Protocol provides that "[i]f the date for making the Annual Update posting/filing should fall on a weekend or a holiday recognized by the FERC, then the posting/filing shall be due on the next business day."

Update as an informational filing with the Commission.[3] The annual transmission revenue requirements identified in the Annual Update are used to derive the Network Integration Transmission Service and Point-to-Point rates under the PJM OATT for service in the ATSI zone.

The revenue requirements submitted in this Annual Update will be used to derive the transmission rates for service on and after June 1, 2011 through May 31, 2012. Each input to the formula rate is either taken directly from the FERC Form No. 1 or reconcilable to the FERC Form No. 1 by the application of clearly identified and supported information.[4] The Annual Update is subject to the review procedures set forth in Section 2 of the ATSI Protocol.

Section 1.f. of the Protocol provides that the Annual Update will provide notice of material changes in ATSI's accounting policies and practices from those in effect for the calendar year upon which the immediately preceding Annual Update was based ("Material Accounting Changes"). Because this is the first year that ATSI's formula rate is in effect in PJM, there is no preceding Annual Update. However, ATSI can report that there are no Material Accounting Changes from the previous calendar year upon which ATSI's 2010 rates in the Midwest ISO were based.

The 2011 Annual Update is attached to this filing as Attachment A.[5] It includes ATSI's formula rate template, which includes Attachment H-21A and Appendices A-G, populated, where appropriate, with inputs for 2011.[6]

Workpapers that support the Annual Update are attached as Attachment B. Each of the supporting workpapers is separately described below.

Workpaper 1 (Other Electric Revenue): Supporting the value listed on Line 35, Page 4 of Attachment H-21A.

Workpaper 2 (Adjustments to Rate Base (Account 255)): Supporting the value for Account 255 that appears on Line 23, Page 2 of Attachment H-21A.

---

[3] ATSI Protocol, Section 1.b.

[4] ATSI Protocol, Note.1. The formula rate inputs for (i) rate of return on common equity; (ii) "Post-Employment Benefits Other Than Pension" pursuant to Accounting Standards Codification 712-10, "Compensation-Nonretirement Postemployment Benefits;" (iii) extraordinary property losses; and (iv) depreciation and/or amortization rates are stated values. *Id.*, Section 1.g. Further, Line 8, Page 1 of Attachment H-21A lists a value of 13,184.1 MW. As described in Note A of Attachment H-21A, that value was provided by PJM.

[5] All of the Appendices and worksheets set forth in ATSI's filed formula rate are included in Attachment A, although the worksheet for Appendix D (Transmission Enhancement Credit) and Appendix G (Revenue Credit Adjustment Calculation) are not being utilized for this particular Annual Update.

[6] In Footnote A of Appendix F of Attachment H-21, there is a reference to Schedule YY of the Midwest ISO tariff. Subsequent to the submission of Attachment H-21 on February 1, 2011, the Midwest ISO changed the designation of Schedule YY to Schedule II.

Workpaper 3 (RTO Realignment Cost Adjustment Accumulated Balance): Supporting the value listed on Line 5 of Appendix C of Attachment H-21A.

Workpaper 4 (Deferred Income Tax Rate): Supporting the deferred income tax rate listed on Line 6 of Appendix C, Line 6 of Appendix F, and Line 3 of Appendix G of Attachment H-21A.

Workpaper 5 (Legacy MTEP Debit): Supporting the value listed on Line 1 of Appendix F of Attachment H-21A.

Workpaper 6 (Treatment of Merger Transaction Costs): Confirming proper treatment of merger transaction costs and exclusion of those costs from transmission rates.

ATSI will make copies of this filing available for inspection at its offices. ATSI also will submit this filing to PJM for posting on its website (www.PJM.com). Moreover, pursuant to Section 1.e of the ATSI Protocol, ATSI will make available a "workable" Excel file containing the Annual Update data to eligible entities upon their written request.

Communications

Communications with respect to this filing should be directed to:

Morgan E. Parke, Esq.
Sr. Corporate Counsel
FirstEnergy Service Company
76 South Main Street
Akron, OH 44308
(330) 384-5795

Richard A. Ziegler
Director, FERC & RTO Technical Support
76 South Main Street
Akron, OH 44308
(330) 761-4370

Kenneth G. Jaffe, Esq.
Richard P. Sparling, Esq.
Bradley R. Miliauskas, Esq.
Alston & Bird, LLP
950 F Street, NW
Washington, DC 20004
(202) 239-3300

Please contact the undersigned if you have any questions.

Respectfully submitted,

Kenneth G. Jaffe

Kenneth G. Jaffe
Richard P. Sparling
Bradley R. Miliauskas
Alston & Bird, LLP
950 F Street, NW
Washington, DC 20004
(202) 239-3300

Attorneys for American Transmission Systems, Incorporated

Attachment A
2011 Annual Update

Formula Rate - Non-Levelized | Rate Formula Template Utilizing FERC Form 1 Data | For the 12 months ended 12/31/10

American Transmission Systems, Inc.

Line No.			Total	Allocator		NPA	Allocated Amount	Below 138 KV
1	GROSS REVENUE REQUIREMENT (page 3, line 29, col 5)						$ 200,758,177	
1a	GROSS REVENUE REQUIREMENT BELOW 138 KV (line 1 times NPA)					30.603500%		$ 61,439,028
	REVENUE CREDITS	(Note T)						
2	Account No. 454	(page 4, line 34 & 34a)	(11,649)	TP	1.00000		(11,649)	(3,565)
3	Account No. 456	(page 4, line 35)	6,543,267	TP	1.00000		6,543,267	0
4a	Revenues from Grandfathered Interzonal Transactions		0	TP	1.00000		0	0
4b	Revenues from service provided by the ISO at a discount		0	TP	1.00000		0	0
5a	Legacy MTEP Credit (Appendix E, page 2, line 3, col. 12)		362,158	TP	1.00000		362,158	N/A
5b	Legacy MTEP Debit (Appendix F, line 13, col. 3, enter negative)		(1,797,269)	TP	1.00000		(1,797,269)	N/A
5c	RRCA (Appendix C, line 13, col. 3, enter negative)		(7,592,112)	TP	1.00000		(7,592,112)	N/A
5d	Transmission Enhancement Credit (Appendix D, page 2, line 2, col. 10)		0	TP	1.00000		0	N/A
6	TOTAL REVENUE CREDITS (sum lines 2-5d)		$ (2,495,606)				$ (2,495,606)	$ (3,565)
7	NET REVENUE REQUIREMENT	(line 1 minus line 6)					$ 203,253,783	$ 61,442,593

Line No.	DIVISOR		Total		Below 138 KV
8	1 Coincident Peak (CP) (MW)	(Note A)	13,184.1	34.9%	4,601.3
9	Average 12 CPs (MW)	(Note B)	10,504.9	34.9%	3,666.2
10	Reserved		0		0
11	Reserved		0		0
12	Reserved		0		0
13	Reserved		0		0
14	Reserved		0		0
15	Reserved				

Line No.			138KV and Above	Below 138 KV
16	Annual Network Rate ($/MW/Yr)	(line 7 / line 8)		$ 13,353.45
16a	Annual Network Rate ($/MW/Yr)	(diff. line 7 / line 8 total)	$ 10,756.23	

Line No.			Peak Rate 138KV and Above	Peak Rate Below 138 KV	Off-Peak Rate 138KV and Above	Off-Peak Rate Below 138 KV
17	Point-To-Point Rate ($/MW/Year)	(line 7 / line 9)		$16,759.00		$ 16,759.00
17a	Point-To-Point Rate ($/MW/Year)	(diff. line 7 / line 9 total)	$ 13,500.00		$ 13,500.00	
18	Point-To-Point Rate ($/MW/Month)	(line 17/12; line 17a/12)	$ 1,125.00	$ 1,397.00	$ 1,125.00	$ 1,397.00
19	Point-To-Point Rate ($/MW/Week)	(line 17/52; line 17a/52)	$ 259.60	$ 322.30	$ 259.60	$ 322.30
20	Point-To-Point Rate ($/MW/Day)	(line 19/5; line 19/7)	$ 51.92	$ 64.46	$ 37.09	$ 46.04
21	Point-To-Point Rate ($/MWh)	(line 17,17a/4,160; line 17,17a/8,760)	$ 3.25	$ 4.03	$ 1.54	$ 1.91

Formula Rate - Non-Levelized

Rate Formula Template
Utilizing FERC Form 1 Data

For the 12 months ended 12/31/10

American Transmission Systems, Inc.

Line No.	(1)	(2) Form No. 1 Page, Line, Col.	(3) Company Total		(4) Allocator	(5) Transmission (Col 3 times Col 4)	(6) Transmission Below 138 KV
	RATE BASE:						
	GROSS PLANT IN SERVICE						
1	Production	205.46.g	0	NA			
2	Transmission	207.58.g & Note U	1,553,084,881	TP	1.00000	1,553,084,881	402,021,359
3	Distribution	207.75.g	0	NA			
4	General & Intangible	205.5.g & 207.99.g	27,577,472	W/S	1.00000	27,577,472	
5	Common	356.1	0	CE	1.00000	0	
6	TOTAL GROSS PLANT (sum lines 1-5)		1,580,662,353	GP=	100.000%	1,580,662,353	
	ACCUMULATED DEPRECIATION						
7	Production	219.20-24.c	0	NA			
8	Transmission	219.25.c & Note U	865,154,383	TP	1.00000	865,154,383	191,490,551
9	Distribution	219.26.c	0	NA			
10	General & Intangible	219.28.c	3,822,871	W/S	1.00000	3,822,871	
11	Common	356.1	0	CE	1.00000	0	
12	TOTAL ACCUM. DEPRECIATION (sum lines 7-11)		868,977,254			868,977,254	
	NET PLANT IN SERVICE						
13	Production	(line 1- line 7)	0				
14	Transmission	(line 2- line 8)	687,930,498			687,930,498	210,530,808
15	Distribution	(line 3 - line 9)	0				
16	General & Intangible	(line 4 - line 10)	23,754,601			23,754,601	
17	Common	(line 5 - line 11)	0			0	
18	TOTAL NET PLANT (sum lines 13-17)		711,685,099	NP=	100.000%	711,685,099	
18a	Percentage of below 138 KV transmission plant (line 14, col 6 divided by col 5)			NPA	30.603500%		
	ADJUSTMENTS TO RATE BASE (Note F)						
19	Account No. 281 (enter negative)	273.8.k	0	NA	zero	0	
20	Account No. 282 (enter negative)	275.2.k	(157,260,411)	NP	1.00000	(157,260,411)	
21	Account No. 283 (enter negative)	277.9.k	(1,784,325)	NP	1.00000	(1,784,325)	
22	Account No. 190	234.8.c	69,309,811	NP	1.00000	69,309,811	
23	Account No. 255 (enter negative)	267.8.h	(39,199)	NP	1.00000	-39,199	
24	TOTAL ADJUSTMENTS (sum lines 19- 23)		(89,774,124)			(89,774,124)	
25	LAND HELD FOR FUTURE USE	214.x.d (Note G)	183,776	TP	1.00000	183,776	
	WORKING CAPITAL (Note H)						
26	CWC	calculated	7,329,649			7,113,797	
27	Materials & Supplies (Note G)	227.8.c & .16.c	0	TE	0.96315	0	
28	Prepayments (Account 165)	111.57.c	627,960	GP	1.00000	627,960	
29	TOTAL WORKING CAPITAL (sum lines 26 - 28)		7,957,609			7,741,757	
30	RATE BASE (sum lines 18, 24, 25, & 29)		630,052,360			629,836,508	

Formula Rate - Non-Levelized

Rate Formula Template
Utilizing FERC Form 1 Data

For the 12 months ended 12/31/10

American Transmission Systems, Inc.

Line No.	(1)	(2) Form No. 1 Page, Line, Col.	(3) Company Total	(4) Allocator		(5) Transmission (Col 3 times Col 4)
	O&M					
1	Transmission	321.112.b	46,706,292	TE	0.96315	44,985,130
1a	Less LSE Expenses Included in Transmission O&M Accounts (Note W)		0		1.00000	
2	Less Account 565	321.96.b	0		1.00000	0
3	A&G	323.197.b	11,930,898	W/S	1.00000	11,930,898
4	Less FERC Annual Fees		0	W/S	1.00000	0
5	Less EPRI & Reg. Comm. Exp. & Non-safety Ad. (Note I)		153,450	W/S	1.00000	153,450
5a	Plus Transmission Related Reg. Comm. Exp. (Note I)		153,450	TE	0.96315	147,795
6	Common	356.1	0	CE	1.00000	0
7	Transmission Lease Payments		0		1.00000	0
8	TOTAL O&M (sum lines 1, 3, 5a, 6, 7 less 1a, 2, 4, 5)		58,637,190			56,910,373
	DEPRECIATION EXPENSE					
9	Transmission	336.7.b	35,986,436	TP	1.00000	35,986,436
10	General	336.10.b	453,070	W/S	1.00000	453,070
11	Common	336.11.b	0	CE	1.00000	0
12	TOTAL DEPRECIATION (sum lines 9 - 11)		36,439,506			36,439,506
	TAXES OTHER THAN INCOME TAXES (Note J)					
	LABOR RELATED					
13	Payroll	263.i	264,172	W/S	1.00000	264,172
14	Highway and vehicle	263.i	5,851	W/S	1.00000	5,851
15	PLANT RELATED					
16	Property	263.i	29,354,254	GP	1.00000	29,354,254
17	Gross Receipts	263.i	-7,866	NA	zero	0
18	Other	263.i	5,434	GP	1.00000	5,434
19	Payments in lieu of taxes		0	GP	1.00000	0
20	TOTAL OTHER TAXES (sum lines 13 - 19)		29,621,845			29,629,711
	INCOME TAXES	(Note K)				
21	T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =		35.50%			
22	CIT=(T/1-T) * (1-(WCLTD/R)) =		38.90%			
	where WCLTD=(page 4, line 27) and R= (page 4, line30)					
	and FIT, SIT & p are as given in footnote K.					
23	1 / (1 - T) = (from line 21)		1.5503			
24	Amortized Investment Tax Credit (266.8f) (enter negative)		(746,075)			
25	Income Tax Calculation = line 22 * line 28		22,112,311	NA		22,104,736
26	ITC adjustment (line 23 * line 24)		(1,156,674)	NP	1	(1,156,674)
27	Total Income Taxes	(line 25 plus line 26)	20,955,637			20,948,062
28	RETURN		56,850,002	NA		56,830,525
	[Rate Base (page 2, line 30) * Rate of Return (page 4, line 30)]					
29	GROSS REV. REQUIREMENT		202,504,180			200,758,177
	(sum lines 8, 12, 20, 27, 28)					

Formula Rate - Non-Levelized | Rate Formula Template Utilizing FERC Form 1 Data | For the 12 months ended 12/31/10

American Transmission Systems, Inc.

SUPPORTING CALCULATIONS AND NOTES

Line No.	(1)	(2)	(3)	(4)	(5)	(6)		
	TRANSMISSION PLANT INCLUDED IN ISO RATES							
1	Total transmission plant (page 2, line 2, column 3)					1,553,084,881		
2	Less transmission plant excluded from ISO rates (Note M)					0		
3	Less transmission plant included in OATT Ancillary Services (Note N)					0		
4	Transmission plant included in ISO rates (line 1 less lines 2 & 3)					1,553,084,881		
5	Percentage of transmission plant included in ISO Rates (line 4 divided by line 1)				TP=	1.00000		
	TRANSMISSION EXPENSES							
6	Total transmission expenses (page 3, line 1, column 3)					46,706,292		
7	Less transmission expenses included in OATT Ancillary Services (Note L)					1,721,162		
8	Included transmission expenses (line 6 less line 7)					44,985,130		
9	Percentage of transmission expenses after adjustment (line 8 divided by line 6)					0.96315		
10	Percentage of transmission plant included in ISO Rates (line 5)				TP	1.00000		
11	Percentage of transmission expenses included in ISO Rates (line 9 times line 10)				TE=	0.96315		
	WAGES & SALARY ALLOCATOR (W&S)							
		Form 1 Reference	$	TP	Allocation			
12	Production	354.20.b	0	0.00	0			
13	Transmission	354.21.b	2,634,543	1.00	2,634,543			
14	Distribution	354.23.b	0	0.00	0	W&S Allocator		
15	Other	354.24,25,26.b	0	0.00	0	($ / Allocation)		
16	Total (sum lines 12-15)		2,634,543		2,634,543 =	1.00000 = WS		
	COMMON PLANT ALLOCATOR (CE) (Note O)							
			$		% Electric	W&S Allocator		
17	Electric	200.3.c	1,544,768,135		(line 17 / line 20)	(line 16)		CE
18	Gas	201.3.d	0		1.00000 *	1.00000	=	1.00000
19	Water	201.3.e	0					
20	Total (sum lines 17 - 19)		1,544,768,135					
	RETURN (R)					$		
21		Long Term Interest (117, sum of 62c through 67c)				$21,827,525		
22		Preferred Dividends (118.29c) (positive number)				$ -		
		Development of Common Stock:						
23		Proprietary Capital (112.16c)				424,932,059		
24		Less Preferred Stock (line 28)				0		
25		Less Account 216.1 (112.12c) (enter negative)				0		
26		Common Stock	(sum lines 23-25)			424,932,059		
			$	%	Cost (Note P)	Weighted		
27	Long Term Debt (112, sum of 18 through 21)		400,000,000	48%	0.0546	0.0265 =WCLTD		
28	Preferred Stock (112.3d)		0	0%	0.0000	0.0000		
29	Common Stock (line 26)		424,932,059	52%	0.1238	0.0638		
30	Total (sum lines 27-29)		824,932,059		0	0.0902 =R		
	REVENUE CREDITS							
	ACCOUNT 447 (SALES FOR RESALE)		(310-311)	(Note Q)				
31	a. Bundled Non-RQ Sales for Resale (311.x.h)					0		
32	b. Bundled Sales for Resale included in Divisor on page 1					0		
33	Total of (a)-(b)					0		
					NPA			Below 138 KV
34	ACCOUNT 454 (RENT FROM ELECTRIC PROPERTY) (Note R)					-$11,649		
34a	Amount line 34 allocated to below 138 KV facilities		-$11,649		30.60350%			-$3,565
35	ACCOUNT 456 (OTHER ELECTRIC REVENUES) (Note V)		(330.x.n)			$6,543,267		

Formula Rate - Non-Levelized | Rate Formula Template
Utilizing FERC Form 1 Data | For the 12 months ended 12/31/10

American Transmission Systems, Inc.

General Note: References to pages in this formulary rate are indicated as: (page#, line#, col.#)
References to data from FERC Form 1 are indicated as: #.y.x (page, line, column)

Note Letter	
A	As provided by PJM and in effect at the time of the annual rate calculations pursuant to Section 34.1 of the PJM OATT. The percentage of load served below 138 kV for the ATSI zone shall be updated annually in accordance with the settlement agreement in Docket No. ER05-285.
B	Peak as would be reported on page 401, column d of Form 1 at the time of the zonal peak for the twelve month period ending October 31 of the calendar year used to calculate rates. The percentage of load served below 138 kV for the ATSI zone shall be updated annually in accordance with the settlement agreement in Docket No. ER05-285.
C	Reserved
D	Reserved
E	Reserved
F	The balances in Accounts 190, 281, 282 and 283, as adjusted by any amounts in contra accounts identified as regulatory assets or liabilities related to FASB 106 or 109. Balance of Account 255 is reduced by prior flow throughs and excluded if the utility chose to utilize amortization of tax credits against taxable income as discussed in Note K. Account 281 is not allocated.
G	Identified in Form 1 as being only transmission related.
H	Cash Working Capital assigned to transmission is one-eighth of O&M allocated to transmission at page 3, line 8, column 5. Prepayments are the electric related prepayments booked to Account No. 165 and reported on Page 111, line 57 in the Form 1.
I	Line 5 - EPRI Annual Membership Dues listed in Form 1 at 353.f, all Regulatory Commission Expenses itemized at 351.h, and non-safety related advertising included in Account 930.1. Line 5a - Regulatory Commission Expenses directly related to transmission service, ISO filings, or transmission siting itemized at 351.h.
J	Includes only FICA, unemployment, highway, property, gross receipts, and other assessments charged in the current year. Taxes related to income are excluded. Gross receipts taxes are not included in transmission revenue requirement in the Rate Formula Template, since they are recovered elsewhere.
K	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". If the utility is taxed in more than one state it must attach a work paper showing the name of each state and how the blended or composite SIT was developed. Furthermore, 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) multiplied by (1/1-T) (page 3, line 26).

Inputs Required:			
	FIT =	35.00%	
	SIT=	0.77%	(State Income Tax Rate or Composite SIT)
	p =	0.00%	(percent of federal income tax deductible for state purposes)

L	Removes dollar amount of transmission expenses included in the OATT ancillary services rates, including Account Nos. 561.1 - 561.3, and 561.BA.
M	Removes transmission plant determined by Commission order to be state-jurisdictional according to the seven-factor test (until Form 1 balances are adjusted to reflect application of seven-factor test).
N	Removes dollar amount of transmission plant included in the development of OATT ancillary services rates and generation step-up facilities, which are deemed included in OATT ancillary services. For these purposes, generation step-up facilities are those facilities at a generator substation on which there is no through-flow when the generator is shut down.
O	Enter dollar amounts
P	Debt cost rate = long-term interest (line 21) / long term debt (line 27). Preferred cost rate = preferred dividends (line 22) / preferred outstanding (line 28). ROE will be supported in the original filing and no change in ROE may be made absent a filing with FERC.
Q	Line 33 must equal zero since all short-term power sales must be unbundled and the transmission component reflected in Account No. 456.1 and all other uses are to be included in the divisor.
R	Includes income related only to transmission facilities, such as pole attachments, rentals and special use.
S	Reserved
T	The revenues credited on page 1, lines 2-4b shall include only the amounts received directly (in the case of grandfathered agreements) or from the ISO (for service under this tariff) reflecting the Transmission Owner's integrated transmission facilities. They do not include revenues associated with FERC annual charges, gross receipts taxes, ancillary services, or facilities not included in this template (e.g., direct assignment facilities and GSUs) which are not recovered under this Rate Formula Template. The revenues on lines 5a-5d are supported by separate references for each item.
U	Gross plant and depreciation reserve balances for facilities below 138 kV are reported in a footnote to the FERC Form 1 pages.
V	On Line 35, enter revenues from RTO settlements that are associated with NITS and firm Point-to-Point Service for which the load is not included in the divisor to derive ATSI's zonal rates. Exclude non-firm Point-to-Point revenues, and revenues related to MTEP and RTEP projects. Include revenues and revenue adjustments associated with Docket EL02-111, and revenue credit adjustments related to ATSI's PJM integration as supported by Appendix G.
W	Account Nos. 561.4, 561.8, and 575.7 consist of RTO expenses billed to load-serving entities and are not included in Transmission Owner revenue requirements.
X	Reserved
Y	Reserved
Z	Reserved

Schedule 1A Rate Calculation

1	$ 1,721,162	Attachment H-21A, Page 4, Line 7
2	$ -	Revenue Credits for Sched 1A - Note A
3	$ 1,721,162	Net Schedule 1A Expenses (Line 1 - Line 2)
4	66,807,357	Annual MWh in ATSI Zone - Note B
5	$ 0.0258	Schedule 1A rate $/MWh (Line 3/ Line 4)

Note:

A Revenues received pursuant to PJM Schedule 1A revenue allocation procedures for transmission service outside of ATSI's zone during the year used to calculate rates under Attachment H-21A.

B Load expressed in MWh consistent with load used for billing under Schedule 1A for the ATSI zone. Data from RTO settlement systems for the calendar year prior to the rate year.

Dual Voltage Billing Factors Calculation Example

(Current Dual Voltage Billing factors and Rates are posted on PJM.com on the MSWG page)

Assumptions:

Total Annual Peak Load for ATSI Zone = 12,000 MW, with the breakdown of the peak within each state approved service territory below:

CEI: 4,100 MW
OE: 5,000 MW
PP: 900 MW
TE: 2,000 MW

Based on engineering studies, the percentage of ATSI's total annual peak load deemed to be utilizing transmission facilities below 138 kV is 34%, with 0% in CEI's territory, 22% in OE's territory, 5% in PennPower's territory, and 7% in TE's territory.

Two municipal/rural customers have loads metered at each interconnection point.

Customers A and B's peak loads for each of the 3 service territories having transmission facilities below 138 kV facilities are provided below:

	OE	TE	PP
Customer A			
Total Metered Load	50	25	10
Metered load at locations served below 138 kV	40	25	10
Customer B			
Total Metered Load	20	10	-
Metered load at locations served below 138 kV	15	10	-

Transmission Rates

138 kV and above	$	1,000	/MW-month
Below 138 kV	$	1,200	/MW-month

Dual Voltage Billing Factors Calculation Example

(Current Dual Voltage Billing factors and Rates are posted on PJM.com)

	(1)	(2)	(3)=(2)/(1)
	NPLS- Network Peak Load (MW)	NPLS-Network Peak Load Utilizing Below 138 kV Facilities	Billing Factor for Below 138 kV % Load
Total For ATSI Zone	**12,000**	**4,080**	**34.00%**
Cleveland Electric Illuminating (CEI)			
CEI Total	4,100	0	0.00%
CEI Wholesale, Retail, POLR Load Suppliers	4,100	0	0.00%
Ohio Edison (OE)			
OE Total	5,000	2,640	52.80%
Specifically Metered Wholesale Load			
Customer A	50	40	80.00%
Customer B	20	15	75.00%
	70	55	
OE Retail, POLR Load Suppliers	4,930	2,585	52.43%
Toledo Edison (TE)			
TE Total	2,000	840	42.00%
Specifically Metered Wholesale Load			
Customer A	25	25	100.00%
Customer B	10	10	100.00%
	35	35	
TE Retail, POLR Load Suppliers	1,965	805	40.97%
Pennsylvania Power (PP)			
PP Total	900	600	66.67%
Specifically Metered Wholesale Load			
Customer A	10	10	100.00%
Customer B	-	-	N/A
	10	10	
PP Retail, POLR Load Suppliers	890	590	66.29%

Dual Voltage Billing Factors Calculation Example

(Current Dual Voltage Billing factors and Rates are posted on PJM.com)

Calculation of Monthly Transmission Bill Based Using the Dual Voltage Rates

Example: For a Transmission Customer serving 100 MW of retail load in Ohio Edison (OE) territory:

1) Multiply the Customer's Daily Average NPLS by the '138 kV and Above Rate' to get the 138 kV and above portion of the bill.

100 MW x $1,000.00=$100,000

2) Multiply the Daily Average NPLS by the Billing Factor for OE Retail Load, then multiply the resultant product by the 'Below 138 kV Rate'

100 MW x 52% = 52 MW
52 MW x $1,200= $62,400

3) Add the results of step 1 and 2 to get the total NITS charges.

$100,000 + $62,400 =$162,400

RTO Realignment Cost Adjustment ("RRCA")
To be completed in conjunction with Attachment H-21A

Line No.	(1)	(2) Reference	(3) Company Total	
	EXPENSES			
1	Monthly amount of RTO Realignment Costs Includable in Net Revenue Requirements	(Note A)	$	627,608
2	Annual amount of RTO Realignment Costs Includable in Net Revenue Requirements (12 * Line 1)		$	7,531,296
3	Expense True-Up Adjustment	(Note B)	$	-
4	Total Expense (Lines 2 + 3)		$	7,531,296
	ACCUMULATED RRCA BALANCE			
5	Accumulated Balance	(Note C)	$	2,113,524
6	Deferred Income Tax Rate	(Note D)		36.255830%
7	Deferred Income Taxes (Line 5 * Line 6)		$	766,276
8	Regulatory Rate Base (Line 5 - Line 7)		$	1,347,248
	INCOME TAXES			
9	CIT=(T/1-T) * (1-(WCLTD/R))	Attachment H-21A, page 3, line 22		38.90%
10	Income Taxes (Line 9 * Line 12)		$	17,031
	RETURN			
11	FERC Refund Rate	(Note E)		3.25%
12	Return (Line 11 * Line 8)		$	43,786
13	RTO Realignment Cost Adjustment (Lines 4 + 10 + 12)		$	7,592,112

Note Letter	
A	Monthly amount of RTO Realignment Costs authorized by FERC to be included in Net Revenue Requirements. Such amount shall be $0 for the last rate period in which an amount on Line 3 appears.
B	The accumulated balance at the end of the current rate period when 1.) the accumulated balance is projected to be negative, and 2.) all RTO Realignment Costs have been authorized by the Commission and paid by ATSI.
C	Accumulated balance as of December 31 of the calendar year prior to the rate year (Column 7 of RRCA Worksheet). However, such amount shall be $0 for the last rate period in which an amount on Line 3 appears.
D	Effective deferred tax rate as of December 31 of the calendar year prior to the rate year.
E	The applied FERC Refund Rate is the rate approved as of December 31 of the calendar year prior to the rate year, as described under section 35.19a(a)(2) of the Commission’s Regulations, 18 C.F.R. § 35.19a(a)(2) (2005).

RRCA Worksheet

(1)	(2)	(3)	(4) = (2)-(3)	(5)	(6)=(4)-(5)	(7)=Prior Month's Balance + (6)
Month	RRCs Paid by ATSI	RRCs Included in ATSI's Net Revenue Requirements	Difference Between RRCs Paid and Amount in Net Revenue Requirements	True-up Adjustment Included in ATSI's Net Revenue Requirements Divided by 12	Amount to be Added to Accumulated Balance	Accumulated Balance
Dec-10						$ 2,113,524
Jan-11	$ 50,112	$ -	$ 50,112	$ -	$ 50,112	$ 2,163,636
Feb-11	$ -	$ -	$ -	$ -	$ -	$ 2,163,636
Mar-11	$ 88,486	$ -	$ 88,486	$ -	$ 88,486	$ 2,252,122
Apr-11		$ -	$ -	$ -	$ -	$ 2,252,122
May-11		$ -	$ -	$ -	$ -	$ 2,252,122
Jun-11	$ -		$ -	$ -	$ -	$ 2,252,122
Jul-11			$ -	$ -	$ -	$ 2,252,122
Aug-11	$ -		$ -	$ -	$ -	$ 2,252,122
Sep-11	$ -		$ -	$ -	$ -	$ 2,252,122
Oct-11	$ -		$ -	$ -	$ -	$ 2,252,122
Nov-11	$ -		$ -	$ -	$ -	$ 2,252,122
Dec-11	$ -		$ -	$ -	$ -	$ 2,252,122
Total			$ -	$ -	$ -	
Jan-12	$ -		$ -	$ -	$ -	$ 2,252,122
Feb-12	$ -		$ -	$ -	$ -	$ 2,252,122
Mar-12	$ -		$ -	$ -	$ -	$ 2,252,122
Apr-12	$ -		$ -	$ -	$ -	$ 2,252,122
May-12	$ -		$ -	$ -	$ -	$ 2,252,122
Jun-12	$ -		$ -	$ -	$ -	$ 2,252,122
Jul-12	$ -		$ -	$ -	$ -	$ 2,252,122
Aug-12	$ -		$ -	$ -	$ -	$ 2,252,122
Sep-12	$ -		$ -	$ -	$ -	$ 2,252,122
Oct-12	$ -		$ -	$ -	$ -	$ 2,252,122
Nov-12	$ -		$ -	$ -	$ -	$ 2,252,122
Dec-12	$ -		$ -	$ -	$ -	$ 2,252,122
Total			$ -	$ -	$ -	
Jan-13	$ -		$ -	$ -	$ -	$ 2,252,122
Feb-13	$ -		$ -	$ -	$ -	$ 2,252,122
Mar-13	$ -		$ -	$ -	$ -	$ 2,252,122
Apr-13	$ -		$ -	$ -	$ -	$ 2,252,122
May-13	$ -		$ -	$ -	$ -	$ 2,252,122
Jun-13	$ -		$ -	$ -	$ -	$ 2,252,122
Jul-13	$ -		$ -	$ -	$ -	$ 2,252,122
Aug-13	$ -		$ -	$ -	$ -	$ 2,252,122
Sep-13	$ -		$ -	$ -	$ -	$ 2,252,122
Oct-13	$ -		$ -	$ -	$ -	$ 2,252,122
Nov-13	$ -		$ -	$ -	$ -	$ 2,252,122
Dec-13	$ -		$ -	$ -	$ -	$ 2,252,122
Total			$ -	$ -	$ -	

RRCA Worksheet

(1)	(2)	(3)	(4) = (2)-(3)	(5)	(6)=(4)-(5)	(7)=Prior Month's Balance + (6)
Month	**RRCs Paid by ATSI**	**RRCs Included in ATSI's Net Revenue Requirements**	**Difference Between RRCs Paid and Amount in Net Revenue Requirements**	**True-up Adjustment Included in ATSI's Net Revenue Requirements Divided by 12**	**Amount to be Added to Accumulated Balance**	**Accumulated Balance**
Jan-14	$ -		$ -	$ -	$ -	$ 2,252,122
Feb-14	$ -		$ -	$ -	$ -	$ 2,252,122
Mar-14	$ -		$ -	$ -	$ -	$ 2,252,122
Apr-14	$ -		$ -	$ -	$ -	$ 2,252,122
May-14	$ -		$ -	$ -	$ -	$ 2,252,122
Jun-14	$ -		$ -	$ -	$ -	$ 2,252,122
Jul-14	$ -		$ -	$ -	$ -	$ 2,252,122
Aug-14	$ -		$ -	$ -	$ -	$ 2,252,122
Sep-14	$ -		$ -	$ -	$ -	$ 2,252,122
Oct-14	$ -		$ -	$ -	$ -	$ 2,252,122
Nov-14	$ -		$ -	$ -	$ -	$ 2,252,122
Dec-14	$ -		$ -	$ -	$ -	$ 2,252,122
Total			$ -	$ -	$ -	
Jan-15	$ -		$ -	$ -	$ -	$ 2,252,122
Feb-15	$ -		$ -	$ -	$ -	$ 2,252,122
Mar-15	$ -		$ -	$ -	$ -	$ 2,252,122
Apr-15	$ -		$ -	$ -	$ -	$ 2,252,122
May-15	$ -		$ -	$ -	$ -	$ 2,252,122
Jun-15	$ -		$ -	$ -	$ -	$ 2,252,122
Jul-15	$ -		$ -	$ -	$ -	$ 2,252,122
Aug-15	$ -		$ -	$ -	$ -	$ 2,252,122
Sep-15	$ -		$ -	$ -	$ -	$ 2,252,122
Oct-15	$ -		$ -	$ -	$ -	$ 2,252,122
Nov-15	$ -		$ -	$ -	$ -	$ 2,252,122
Dec-15	$ -		$ -	$ -	$ -	$ 2,252,122
Total			$ -	$ -	$ -	
Jan-16	$ -		$ -	$ -	$ -	$ 2,252,122
Feb-16	$ -		$ -	$ -	$ -	$ 2,252,122
Mar-16	$ -		$ -	$ -	$ -	$ 2,252,122
Apr-16	$ -		$ -	$ -	$ -	$ 2,252,122
May-16	$ -		$ -	$ -	$ -	$ 2,252,122
Jun-16	$ -		$ -	$ -	$ -	$ 2,252,122
Jul-16	$ -		$ -	$ -	$ -	$ 2,252,122
Aug-16	$ -		$ -	$ -	$ -	$ 2,252,122
Sep-16	$ -		$ -	$ -	$ -	$ 2,252,122
Oct-16	$ -		$ -	$ -	$ -	$ 2,252,122
Nov-16	$ -		$ -	$ -	$ -	$ 2,252,122
Dec-16	$ -		$ -	$ -	$ -	$ 2,252,122
Total			$ -	$ -	$ -	
Jan-17	$ -	$ -	$ -	$ -	$ -	$ 2,252,122
Feb-17	$ -	$ -	$ -	$ -	$ -	$ 2,252,122
Mar-17	$ -	$ -	$ -	$ -	$ -	$ 2,252,122
Apr-17	$ -	$ -	$ -	$ -	$ -	$ 2,252,122
May-17	$ -	$ -	$ -	$ -	$ -	$ 2,252,122
Total						

Transmission Enhancement Credit
To be completed in conjunction with Attachment H-21A

	(1)	(2)	(3)	(4)
Line No.		**Reference**	**Transmission**	**Allocator**
1	Gross Transmission Plant - Total	Attach. H-21A, p. 2, line 2, col. 5 (Note A)	$ 1,553,084,881	
2	Net Transmission Plant - Total	Attach. H-21A, p. 2, line 14, col. 5 (Note B)	$ 687,930,498	
	O&M EXPENSE			
3	Total O&M Allocated to Transmission	Attach. H-21A, p. 3, line 8, col. 5	$ 56,910,373	
4	Annual Allocation Factor for O&M	(line 3 divided by line 1, col. 3)	3.664344%	3.664344%
	TAXES OTHER THAN INCOME TAXES			
5	Total Other Taxes	Attach. H-21A, p. 3, line 20, col. 5	$ 29,629,711	
6	Annual Allocation Factor for Other Taxes	(line 5 divided by line 1, col. 3)	1.907797%	1.907797%
7	**Annual Allocation Factor for Expense**	**Sum of line 4 and 6**		**5.572141%**
	INCOME TAXES			
8	Total Income Taxes	Attach. H-21A, p. 3, line 27, col. 5	$ 20,948,062	
9	Annual Allocation Factor for Income Taxes	(line 8 divided by line 2, col. 3)	3.045084%	3.045084%
	RETURN			
10	Return on Rate Base	Attach. H-21A, p. 3, line 28, col. 5	$ 56,830,525	
11	Annual Allocation Factor for Return on Rate Base	(line 10 divided by line 2, col. 3)	8.261085%	8.261085%
12	**Annual Allocation Factor for Return**	**Sum of line 9 and 11**		**11.306169%**

Transmission Enhancement Credit
To be completed in conjunction with Attachment H-21A

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Line No.	**Project Name**	**RTEP Project Number**	**Project Gross Plant**	**Annual Allocation Factor for Expense**	**Annual Expense Charge**	**Project Net Plant**	**Annual Allocation Factor for Return**	**Annual Return Charge**	**Project Depreciation Expense**	**Annual Revenue Requirement**
			(Note C)	(Page 1, line 7)	(Col. 3 * Col. 4)	(Note D)	(Page 1, line 12)	(Col. 6 * Col. 7)	(Note E)	(Sum Col. 5, 8 & 9)
1a	Project 1		$ -	5.572141%	$0	$ -	11.306169%	$0	$ -	$0
1b	Project 2		$ -	5.572141%	$0	$ -	11.306169%	$0	$ -	$0
1c	Project 3		$ -	5.572141%	$0	$ -	11.306169%	$0	$ -	$0
2	Transmission Enhancement Credit for Attachment H-21A Page 1, Line 5d									$ -

Notes

A Gross Transmission Plant is that identified on page 2 line 2 of Attachment H-21A.

B Net Transmission Plant is that identified on page 2 line 14 of Attachment H-21A.

C Project Gross Plant is the total capital investment for the project calculated in the same method as the gross plant value in line 1 above. This value includes subsequent capital investments required to maintain the project in-service.

D Project Net Plant is the Project Gross Plant Identified in Column 3 less the associated Accumulated Depreciation.

E Project Depreciation Expense is the actual value booked for the project and included in the Depreciation Expense in Attachment H-21A page 3 line 12.

For the 12 months ended 12/31/10

Legacy MTEP Credit Calculation
To be completed in conjunction with Attachment H-21A

	(1)	(2)	(3)	(4)
Line No.		**Reference**	**Transmission**	**Allocator**
1	Gross Transmission Plant - Total	Attach. H-21A, p. 2, line 2, col. 5 (Note A)	$ 1,553,084,881	
2	Net Transmission Plant - Total	Attach. H-21A, p. 2, line 14, col. 5 (Note B)	$ 687,930,498	
	O&M EXPENSE			
3	Total O&M Allocated to Transmission	Attach. H-21A, p. 3, line 8, col. 5	$ 56,910,373	
4	Annual Allocation Factor for O&M	(line 3 divided by line 1, col. 3)	3.664344%	3.664344%
	TAXES OTHER THAN INCOME TAXES			
5	Total Other Taxes	Attach. H-21A, p. 3, line 20, col. 5	$ 29,629,711	
6	Annual Allocation Factor for Other Taxes	(line 5 divided by line 1, col. 3)	1.907797%	1.907797%
7	**Annual Allocation Factor for Expense**	**Sum of line 4 and 6**		**5.572141%**
	INCOME TAXES			
8	Total Income Taxes	Attach. H-21A, p. 3, line 27, col. 5	$ 20,948,062	
9	Annual Allocation Factor for Income Taxes	(line 8 divided by line 2, col. 3)	3.045084%	3.045084%
	RETURN			
10	Return on Rate Base	Attach. H-21A, p. 3, line 28, col. 5	$ 56,830,525	
11	Annual Allocation Factor for Return on Rate Base	(line 10 divided by line 2, col. 3)	8.261085%	8.261085%
12	**Annual Allocation Factor for Return**	**Sum of line 9 and 11**		**11.306169%**

Legacy MTEP Credit Calculation
To be completed in conjunction with Attachment H-21A

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
Line No.	**Project Name**	**MTEP Project Number**	**Project Gross Plant**	**Annual Allocation Factor for Expense**	**Annual Expense Charge**	**Project Net Plant**	**Annual Allocation Factor for Return**	**Annual Return Charge**	**Project Depreciation Expense**	**Annual Revenue Requirement**	**ATSI Zone Share**	**MISO Share**
			(Note C)	(Page 1, line 7)	(Col. 3 * Col. 4)	(Note D)	(Page 1, line 12)	(Col. 6 * Col. 7)	(Note E)	(Sum Col. 5, 8 & 9)	(Note F)	Col. 10*(1-Col. 11) (Note G)
1a	North Medina Substation	1	$ 10,146,850	5.572141%	$565,397	$ 9,676,537	11.306169%	$1,094,046	$ 221,156	$1,880,599	91.710000%	$ 155,902
1b	Harding/Juniper Cap Banks	2	$ 6,415,895	5.572141%	$357,503	$ 6,140,765	11.306169%	$694,285	$ 132,231	$1,184,019	82.580000%	$ 206,256
2	Annual Totals									$ 3,064,618		$ 362,158
3	Legacy MTEP Credit for Attachment H-21A Page 1, Line 5a											$ 362,158

Note Letter	
A	Gross Transmission Plant is that identified on page 2 line 2 of Attachment H-21A and includes any sub lines 2a or 2b etc. and is inclusive of any CWIP included in rate base when authorized by FERC order.
B	Net Transmission Plant is that identified on page 2 line 14 of Attachment H-21A and includes any sub lines 14a or 14b etc. and is inclusive of any CWIP included in rate base when authorized by FERC order.
C	Project Gross Plant is the total capital investment for the project calculated in the same method as the gross plant value in line 1 above and includes CWIP in rate base if applicable. This value includes subsequent capital investments required to maintain the project in-service.
D	Project Net Plant is the Project Gross Plant Identified in Column 3 less the associated Accumulated Depreciation.
E	Project Depreciation Expense is the actual value booked for the project and included in the Depreciation Expense in Attachment H-21A page 3 line 12.
F	ATSI Zone allocation from the Midwest ISO MTEP report when the project was approved.
G	MISO Share is the value to be included as a credit in Attachment H-21A page 1, line 5a. The Midwest ISO will recover this amount in MTEP-related charges applicable to Midwest ISO zones.

Legacy MTEP Debit Calculation

To be completed in conjunction with Attachment H-21A

Line No.	(1)	(2) Reference	(3) Company Total
	LEGACY MTEP PROJECT REVENUE REQUIREMENTS		
1	Monthly Revenue Requirements Allocated to ATSI Zone for Legacy MTEP Projects	(Note A)	$ 149,772
2	Annual Legacy MTEP Revenue Requirements Estimated for the Upcoming Rate Year (June-May) (12 * Line 1)		$ 1,797,269
3	Expense True-Up Adjustment	(Note B)	$ -
4	Total Expense (Lines 2 + 3)		$ 1,797,269
	ACCUMULATED MTEP PAYMENT BALANCE		
5	Accumulated Balance	(Note C)	$ -
6	Deferred Income Tax Rate	(Note D)	
7	Deferred Income Taxes (Line 5 * Line 6)		$ -
8	Regulatory Rate Base (Line 5 - Line 7)		$ -
	INCOME TAXES		
9	CIT=(T/1-T) * (1-(WCLTD/R))	Attachment H-21A, page 3, line 22	38.90%
10	Income Taxes (Line 9 * Line 12)		$ -
	RETURN		
11	FERC Refund Rate	(Note E)	3.25%
12	Return (Line 11 * Line 8)		$ -
13	Legacy MTEP Debit (Lines 4 + 10 + 12)		$ 1,797,269

Note Letter	
A	Sum of annual revenue requirements allocated to ATSI's Zone for MTEP projects not constructed by ATSI pursuant to PJM Schedule YY for the months of January - March occurring prior to the start of the rate year, divided by 3 to yield an average annual revenue requirement, and then divided by 12 to yield an average monthly revenue requirement.
B	Difference in amounts paid by the ATSI Zone for Legacy MTEP Projects and the estimated revenue requirements for such projects included in ATSI's Net Revenue Requirements during the calendar year prior to the rate year (Column 4 of Legacy MTEP Debit
C	Accumulated balance as of December 31 of the calendar year prior to the rate year (Column 7 of Legacy MTEP Debit Worksheet).
D	Effective deferred tax rate as of December 31 of the calendar year prior to the rate year.
E	The applied FERC Refund Rate is the rate approved as of December 31 of the calendar year prior to the rate year, as described under section 35.19a(a)(2) of the Commission’s Regulations, 18 C.F.R. § 35.19a(a)(2) (2005).

Legacy MTEP Debit Worksheet

(1) Month	(2) Legacy MTEP Charges Paid by ATSI Zone	(3) Estimate of Legacy MTEP Revenue Requirements Included in ATSI's Net Revenue Requirements Divided by 12	(4) = (2)-(3) Difference Between Charges Paid and Estimate in Net Revenue Requirements	(5) True-up Adjustment Included in ATSI's Net Revenue Requirements Divided by 12	(6)=(4)-(5) Amount to be Added to Accumulated Balance	(7)=Prior Month's Balance + (6) Accumulated Balance
Jun-11			$ -	$ -	$ -	$ -
Jul-11			$ -	$ -	$ -	$ -
Aug-11			$ -	$ -	$ -	$ -
Sep-11			$ -	$ -	$ -	$ -
Oct-11			$ -	$ -	$ -	$ -
Nov-11			$ -	$ -	$ -	$ -
Dec-11			$ -	$ -	$ -	$ -
Total			$ -	$ -	$ -	
Jan-12		$ -	$ -	$ -	$ -	$ -
Feb-12		$ -	$ -	$ -	$ -	$ -
Mar-12		$ -	$ -	$ -	$ -	$ -
Apr-12		$ -	$ -	$ -	$ -	$ -
May-12		$ -	$ -	$ -	$ -	$ -
Jun-12	$ -	$ -	$ -	$ -	$ -	$ -
Jul-12	$ -	$ -	$ -	$ -	$ -	$ -
Aug-12	$ -	$ -	$ -	$ -	$ -	$ -
Sep-12	$ -	$ -	$ -	$ -	$ -	$ -
Oct-12	$ -	$ -	$ -	$ -	$ -	$ -
Nov-12	$ -	$ -	$ -	$ -	$ -	$ -
Dec-12	$ -	$ -	$ -	$ -	$ -	$ -
Total			$ -	$ -	$ -	
Jan-13	$ -	$ -	$ -	$ -	$ -	$ -
Feb-13	$ -	$ -	$ -	$ -	$ -	$ -
Mar-13	$ -	$ -	$ -	$ -	$ -	$ -
Apr-13	$ -	$ -	$ -	$ -	$ -	$ -
May-13	$ -	$ -	$ -	$ -	$ -	$ -
Jun-13	$ -	$ -	$ -	$ -	$ -	$ -
Jul-13	$ -	$ -	$ -	$ -	$ -	$ -
Aug-13	$ -	$ -	$ -	$ -	$ -	$ -
Sep-13	$ -	$ -	$ -	$ -	$ -	$ -
Oct-13	$ -	$ -	$ -	$ -	$ -	$ -
Nov-13	$ -	$ -	$ -	$ -	$ -	$ -
Dec-13	$ -	$ -	$ -	$ -	$ -	$ -
Total			$ -	$ -	$ -	
Jan-14	$ -	$ -	$ -	$ -	$ -	$ -
Feb-14	$ -	$ -	$ -	$ -	$ -	$ -
Mar-14	$ -	$ -	$ -	$ -	$ -	$ -
Apr-14	$ -	$ -	$ -	$ -	$ -	$ -
May-14	$ -	$ -	$ -	$ -	$ -	$ -
Jun-14	$ -	$ -	$ -	$ -	$ -	$ -
Jul-14	$ -	$ -	$ -	$ -	$ -	$ -
Aug-14	$ -	$ -	$ -	$ -	$ -	$ -
Sep-14	$ -	$ -	$ -	$ -	$ -	$ -
Oct-14	$ -	$ -	$ -	$ -	$ -	$ -
Nov-14	$ -	$ -	$ -	$ -	$ -	$ -
Dec-14	$ -	$ -	$ -	$ -	$ -	$ -
Total			$ -	$ -	$ -	
Jan-15	$ -	$ -	$ -	$ -	$ -	$ -
Feb-15	$ -	$ -	$ -	$ -	$ -	$ -
Mar-15	$ -	$ -	$ -	$ -	$ -	$ -
Apr-15	$ -	$ -	$ -	$ -	$ -	$ -
May-15	$ -	$ -	$ -	$ -	$ -	$ -

For the 12 months ended 12/31/10

Revenue Credit Adjustment Calculation
To be completed in conjunction with Attachment H-21A

Line No.	(1)	(2) Reference	(3) Company Total
	REVENUE CREDIT TRUE-UP		
1	Difference Between Revenues Received Under Midwest ISO and PJM Protocols	(Note A)	
	ACCUMULATED REVENUE CREDIT BALANCE		
2	Accumulated Balance	(Note B)	
3	Deferred Income Tax Rate	(Note C)	
4	Deferred Income Taxes (Line 2 * Line 3)		$ -
5	Regulatory Rate Base (Line 2 - Line 4)		$ -
	INCOME TAXES		
6	CIT=(T/1-T) * (1-(WCLTD/R))	Attachment H-21A, page 3, line 22	38.90%
7	Income Taxes (Line 6 * Line 9)		$ -
	RETURN		
8	FERC Refund Rate	(Note D)	
9	Return (Line 5 * Line 8)		$ -
10	Revenue Credit Adjustment (Lines 1 + 7 + 9)		$ -

Note Letter	
A	Revenue Credit Adjustment Worksheet, Column 4 for calendar year prior to rate year.
B	Accumulated balance as of December 31 of the calendar year prior to the rate year (Column 7 of Revenue Credit Adjustment Worksheet).
C	Effective deferred tax rate as of December 31 of the calendar year prior to the rate year.
D	The applied FERC Refund Rate is the rate approved as of December 31 of the calendar year prior to the rate year, as described under section 35.19a(a)(2) of the Commission's Regulations, 18 C.F.R. § 35.19a(a)(2) (2005).

Revenue Credit Adjustment Worksheet

(1)	(2)	(3)	(4) = (2)-(3)	(5)	(6)=(4)-(5)	(7)=Prior Month's Balance + (6)
Month	**Firm PTP and NITS Revenue Received from RTO (Note A)**	**Firm PTP and NITS Revenue Included in Rates Excluding True-Up (Note B)**	**Difference Between Revenues Received and Amount in Rates Excluding True-Up**	**True-up Adjustment Included in ATSI's Net Revenue Requirements Divided by 12**	**Amount to be Added to Accumulated Balance**	**Accumulated Balance**
January - December 2010						
Jan-11						
Feb-11						
Mar-11						
Apr-11						
May-11						
Jun-11			$ -	$ -	$ -	$ -
Jul-11			$ -	$ -	$ -	$ -
Aug-11			$ -	$ -	$ -	$ -
Sep-11			$ -	$ -	$ -	$ -
Oct-11			$ -	$ -	$ -	$ -
Nov-11			$ -	$ -	$ -	$ -
Dec-11			$ -	$ -	$ -	$ -
Total			$ -	$ -	$ -	
Jan-12			$ -	$ -	$ -	$ -
Feb-12			$ -	$ -	$ -	$ -
Mar-12			$ -	$ -	$ -	$ -
Apr-12			$ -	$ -	$ -	$ -
May-12			$ -	$ -	$ -	$ -
Jun-12			$ -	$ -	$ -	$ -
Jul-12			$ -	$ -	$ -	$ -
Aug-12			$ -	$ -	$ -	$ -
Sep-12			$ -	$ -	$ -	$ -
Oct-12			$ -	$ -	$ -	$ -
Nov-12			$ -	$ -	$ -	$ -
Dec-12			$ -	$ -	$ -	$ -
Total			$ -	$ -	$ -	
Jan-13		$ -	$ -	$ -	$ -	$ -
Feb-13		$ -	$ -	$ -	$ -	$ -
Mar-13		$ -	$ -	$ -	$ -	$ -
Apr-13		$ -	$ -	$ -	$ -	$ -
May-13		$ -	$ -	$ -	$ -	$ -
Jun-13			$ -		$ -	$ -
Jul-13			$ -		$ -	$ -
Aug-13			$ -		$ -	$ -
Sep-13			$ -		$ -	$ -
Oct-13			$ -		$ -	$ -
Nov-13			$ -		$ -	$ -
Dec-13			$ -		$ -	$ -
Total			$ -	$ -	$ -	
Jan-14			$ -	$ -	$ -	$ -
Feb-14			$ -	$ -	$ -	$ -
Mar-14			$ -	$ -	$ -	$ -
Apr-14			$ -	$ -	$ -	$ -
May-14			$ -	$ -	$ -	$ -
Total			$ -	$ -	$ -	

Notes

A Revenues received from PJM or Midwest ISO that are associated with NITS and Point-to-Point Service for which the load is not included in the divisor to derive ATSI's zonal rates. Excludes non-firm Point-to-Point revenues, revenues and revenue adjustments associated with Docket EL02-111, and revenues related to MTEP and RTEP projects. Revenues received from PJM for the months of June 2011 - May 2012 will be used for the comparable months of June 2012 - May 2013.

B Revenues received from PJM or Midwest ISO that are associated with NITS and Point-to-Point Service for which the load is not included in the divisor to derive ATSI's zonal rates, and included in the derivation of zonal net revenue requirements, divided by 12. Excludes non-firm Point-to-Point revenues, revenues and revenue adjustments associated with Docket EL02-111, and revenues related to MTEP and RTEP projects.

Attachment B
Workpapers

Workpaper 1 (Other Electric Revenue)

Other Electric Revenue Workpaper

Line	Description	Amount	Reference	Source
1	NITS Transmission Revenues Reported	$ 220,701,288.00	Form 1 - Page 330 Line 4 Col n	FERC Form 1
1a	NITS Collected From Zone	$ 214,845,032.46	NITS Revenue on RTO Invoice	RTO Settlements
1b	MTEP Revenues	$ 5,856,255.54	Schedule 26/ Schedule II Revenues on RTO Invoice	RTO Settlements
1c	RTEP/TEC Revenues	$ -	Schedule 12/ Transmission Expansion Revenues on RTO Invoice	RTO Settlements
2	Total Included on Line 35, Attachment H-21A Page 4	$ (0.00)	Line 1- Line 1a - Line 1b - Line 1c	

Line	Description	Amount	Reference	Source
3	Point-To-Point Revenues Reported	$ 11,884,189.00	Form 1 - Page Line Col	FERC Form 1
3a	LTF Point-To-Point Revenues Related to Load in Divisor	$ 4,299,654.00	Footnote	FERC Form 1
3b	Non-Firm Point-to-Point Revenues	$ 1,041,268.00	Footnote	FERC Form 1
3c	Prior Year Appendix G Revenue Credit Adjustment	$ -	Attach H-21A, Appendix G line 10	Prior Year Attachment H-21A
4	Total Included on Line 35, Attachment H-21A Page 4	$ 6,543,267.00	Line 3- Line 3a - Line 3b - 3 Line 1c	
5	Total reported on Line 35, Attachment H-21A Page 4	$ 6,543,267.00	Line 2 + Line 4	

Workpaper 2 (Adjustments to Rate Base (Account 255))

Accumulated Deferred Investment Tax Credits (Account 255)

Based on prior elections and IRS rulings, the 3% Investment Tax Credit ("ITC") and the 4% ITC may be used to reduce rate base as well as utilizing amortization of the tax credits against taxable income.

As a result, for the rate year beginning in June 2011, the amount included on Attachment H-21A, page 2 of 5, at line 23 is equal to $39,199. This value can be found on FERC Form 1, page 267, at line 3 and column h.

Workpaper 3 (RTO Realignment Cost Adjustment Accumulated Balance)

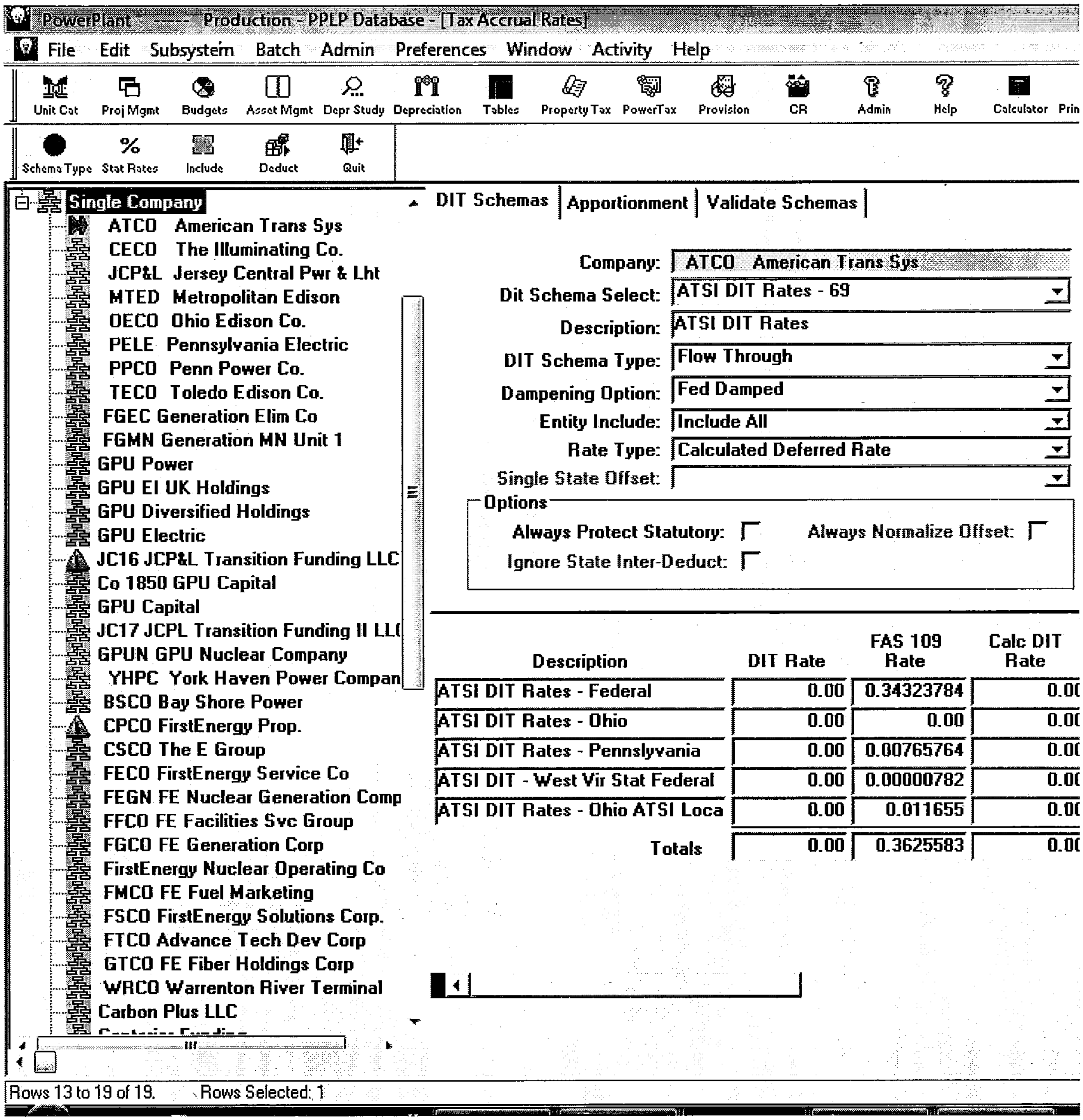
RTO MIGRATION COST VERIFICATION

RTO MIGRATION COSTS PAID TO PJM			
Aug-09	1,200,000.00	550100 PJM	Initial Payment for PJM Services
Sep-09	13,293.81	550100 PJM	PJM Services for August
Oct-09	78,265.85	550100 PJM	PJM Services for September
Nov-09	78,359.68	550100 PJM	PJM Services for October
Dec-09	29,295.86	550100 PJM	PJM Services for November
	1,399,215.20	**2009 TOTAL SPENDING PAID TO PJM**	
Jan-10	36,103.62	550100 PJM	PJM Services for December
Feb-10	81,721.31	550100 PJM	PJM Services for January
Mar-10	88,051.01	550100 PJM	PJM Services for February
Apr-10	111,045.52	550100 PJM	PJM Services for March
May-10	37,841.04	550100 PJM	PJM Services for April
Jun-10	49,764.48	550100 PJM	PJM Services for May
Jul-10	26,040.69	550100 PJM	PJM Services for June
Sep-10	17,525.34	550100 PJM	PJM Services for July
Oct-10	59,577.24	550100 PJM	PJM Services for August
	98,811.99	550100 PJM	PJM Services for September
Nov-10	46,845.44	550100 PJM	PJM Services for October
Dec-10	60,981.57	550100 PJM	PJM Services for November
	714,309.25	**2010 SPENDING TO DATE PAID TO PJM**	
	2,113,524.45	**BALANCE OF SPENDING AT 12/31/10 PAID TO PJM**	
Jan-11	50,121.93	550100 PJM	PJM Services for December
Feb-11	-		
Mar-11	88,486.25	550101 PJM	PJM Services for January & February 2011
	138,608.18	**2011 SPENDING TO DATE PAID TO PJM**	
	2,252,132.63	**PROJECT TO DATE SPENDING PAID TO PJM**	

Workpaper 4 (Deferred Income Tax Rate)

Re: Another Tax Question
William H. Byers to: Gary D. Young 03/29/2011 11:34 AM
Cc: Kevin L. Norris, Joseph A. Gier

ATSI's 2010 tax rate.



PowerPlant ----- Production - PPLP Database - [Tax Accrual Rates]

File Edit Subsystem Batch Admin Preferences Window Activity Help

Unit Cat Proj Mgmt Budgets Asset Mgmt Depr Study Depreciation Tables Property Tax PowerTax Provision CR Admin Help Calculator Prin

Schema Type Stat Rates Include Deduct Quit

Single Company
- ATCO American Trans Sys
- CECO The Illuminating Co.
- JCP&L Jersey Central Pwr & Lht
- MTED Metropolitan Edison
- OECO Ohio Edison Co.
- PELE Pennsylvania Electric
- PPCO Penn Power Co.
- TECO Toledo Edison Co.
- FGEC Generation Elim Co
- FGMN Generation MN Unit 1
- GPU Power
- GPU EI UK Holdings
- GPU Diversified Holdings
- GPU Electric
- JC16 JCP&L Transition Funding LLC
- Co 1850 GPU Capital
- GPU Capital
- JC17 JCPL Transition Funding II LL(
- GPUN GPU Nuclear Company
- YHPC York Haven Power Compan
- BSCO Bay Shore Power
- CPCO FirstEnergy Prop.
- CSCO The E Group
- FECO FirstEnergy Service Co
- FEGN FE Nuclear Generation Comp
- FFCO FE Facilities Svc Group
- FGCO FE Generation Corp
- FirstEnergy Nuclear Operating Co
- FMCO FE Fuel Marketing
- FSCO FirstEnergy Solutions Corp.
- FTCO Advance Tech Dev Corp
- GTCO FE Fiber Holdings Corp
- WRCO Warrenton River Terminal
- Carbon Plus LLC

DIT Schemas | Apportionment | Validate Schemas

Company: ATCO American Trans Sys
Dit Schema Select: ATSI DIT Rates - 69
Description: ATSI DIT Rates
DIT Schema Type: Flow Through
Dampening Option: Fed Damped
Entity Include: Include All
Rate Type: Calculated Deferred Rate
Single State Offset:

Options
Always Protect Statutory:
Always Normalize Offset:
Ignore State Inter-Deduct:

Description	DIT Rate	FAS 109 Rate	Calc DIT Rate
ATSI DIT Rates - Federal	0.00	0.34323784	0.0(
ATSI DIT Rates - Ohio	0.00	0.00	0.0(
ATSI DIT Rates - Pennslyvania	0.00	0.00765764	0.0(
ATSI DIT - West Vir Stat Federal	0.00	0.00000782	0.0(
ATSI DIT Rates - Ohio ATSI Loca	0.00	0.011655	0.0(
Totals	0.00	0.3625583	0.0(

Rows 13 to 19 of 19. Rows Selected: 1

Gary D. Young	Kevin, the deferred income tax rate for year end...	03/29/2011 11:26:26 AM

From:	Gary D. Young/FirstEnergy
To:	Kevin L. Norris/FirstEnergy@FirstEnergy
Cc:	William H. Byers/FirstEnergy, Joseph A. Gier/FirstEnergy
Date:	03/29/2011 11:26 AM
Subject:	Re: Another Tax Question

Kevin, the deferred income tax rate for year end 2010 is 36.2558%. Bill, can you verify that this rate has not changed and provide documentation for the calculation?

Gary D. Young
(330) 384-7998

Workpaper 5 (Legacy MTEP Debit)

H-21A Attachment F- Workpaper Legacy MTEP Charges

Source of Annual Revenue Requirements is Monthly Schedule 26 Summary on Midwest ISO webpage

	Project ID	Project Name	Constructing Owner	Jan 2011- Annual Revenue Req.	Feb 2011- Annual Revenue Req.	Mar 2011- Annual Revenue Req.	Average Annual Revenue Requirement For The First 3 Months of the Year
1	91	Hillcrest 345/138	Duke Energy Ohio	$ 27,989.27	$ 27,989.27	$ 27,989.27	$ 27,989.27
2	286	Fargo, ND - St Cloud/Monticello, MN area 345 kV project	Great River Energy, Northern States Power Company, Otter Tail Power Co	$ 297,007.54	$ 297,007.54	$ 297,007.54	$ 297,007.54
3	345	Morgan - Werner West 345 kV line (includes Clintonville-Werner West 138)	American Transmission Company LLC	$ 772,206.97	$ 772,206.97	$ 772,206.97	$ 772,206.97
4	356	Rockdale-West Middleton 345 kV	American Transmission Company LLC	$ 187,306.81	$ 187,306.81	$ 187,306.81	$ 187,306.81
5	481	Tallmadge 345/138 kV TB3 transformer #3	Michigan Electric Transmission Company, LLC	$ 30,402.02	$ 30,402.02	$ 30,402.02	$ 30,402.02
6	612	Hiple - Add 2nd 345-138 kV Transformer	Northern Indiana Public Service Company	$ 7,192.12	$ 7,192.12	$ 7,192.12	$ 7,192.12
7	662	Weeds Lake	Michigan Electric Transmission Company, LLC	0	0	0	$ -
8	686	Majestic 345/120 kV switching station	International Transmission Company	$ 6,297.81	$ 6,297.81	$ 6,297.81	$ 6,297.81
9	910	Coventry Station upgrade	International Transmission Company	$ 57,926.87	$ 57,926.87	$ 57,926.87	$ 57,926.87
10	911	Placid 345/120 transformer #2	International Transmission Company	$ 61,692.57	$ 61,692.57	$ 61,692.57	$ 61,692.57
11	1004	New 345/138 kV Substation at Francisco	Vectren Energy	$ 23,138.26	$ 23,138.26	$ 23,138.26	$ 23,138.26
12	1024	SE Twin Cities - Rochester, MN - LaCrosse, WI 345 kV project	Northern States Power Company; Southern Minnesota Municipal Power A	$ 26,911.34	$ 26,911.34	$ 26,911.34	$ 26,911.34
13	1257	New Transmission Line Gibson (Cinergy) to AB Brown (Vectren) to Reid (BREC)	Vectren Energy	$ 254,069.81	$ 254,069.81	$ 254,069.81	$ 254,069.81
14	1263	G431 - Edwardsport	Duke Energy Indiana	0	0	0	$ -
15	1457	G287, 37642-03. Upgrades for G287	Northern States Power Company	$ 186.17	$ 186.17	$ 186.17	$ 186.17
16	1458	G349, 37774-01. Upgrades for G349	Northern States Power Company	$ 92.48	$ 92.48	$ 92.48	$ 92.48
17	1749	G172 Mitchell County Substation	ITC Midwest	$ (16,837.00)	$ (16,837.00)	$ (16,837.00)	$ (16,837.00)
18	1817	Midland	Michigan Electric Transmission Company, LLC	$ 61,686.10	$ 61,686.10	$ 61,686.10	$ 61,686.10
19	1828	Argenta-Palisades 345kV ckt. 1 & 2	Michigan Electric Transmission Company, LLC	0	0	0	$ -
20	2068	Latham - Oreana 345 kV line	Ameren Illinois	0	0	0	$ -
21	2069	South Bloomington - Install new 560 MVA 345 /138 Xfmr	Ameren Illinois	0	0	0	$ -
22	2472	New 345kV Supply at Fargo Substation	Ameren Illinois	0	0	0	$ -
23	2793	G883/4 Uprate Point Beach-Sheboygan EC 345-kV	American Transmission Company LLC	0	0	0	$ -
24	2829	Coffeen Plant-Coffeen, North - 2nd. Bus tie	Ameren Illinois	0	0	0	$ -
25	2837	Uprate Cypress-Arcadian 345 kV line	American Transmission Company LLC	0	0	0	$ -
26	3104	G514 Heartland Wind	Great River Energy		0	0	$ -
				3 Month Average Annual Legacy MTEP Revenue Requirements			$ 1,797,269.14

Monthly Revenue Requirement Value to be entered on Line 1 of Appendix F $ 149,772.43 per Month
(3 Month Average Annual Legacy MTEP Revenue Requirements/12 Months)

Workpaper 6 (Treatment of Merger Transaction Costs)

MEMORANDUM

To: Rich Ziegler

From: Kevin Burgess

CC: Steve Law, Kevin Norris

Date: April 8, 2011

Re: Accounting Treatment of Merger Transaction Costs

The purpose of this memorandum is to confirm that the merger transaction costs for calendar year 2010 have been properly recorded for American Transmission Systems, Incorporated ("ATSI") per the FERC Order in Docket No. EC10-68-000, at paragraph 73.[1] Paragraph 73 of the FERC Order states:

> Applicants also estimate that they will incur transaction costs of roughly $120 million, and each jurisdictional subsidiary is charging transaction costs to Account 923, Outside Services, as they are incurred. The Commission has previously determined that merger transaction costs are considered non-operating in nature and should be recorded in Account 426.5, Other Deductions.[2] Account 426.5 includes miscellaneous expense items which are non-operating in nature.[3] The Commission has also determined that post-merger transition costs should be charged to the appropriate operating expense account as incurred.[4] Accordingly, the jurisdictional subsidiaries should record all merger-related costs in Account 426.5 or the appropriate operating expense account as discussed above.

As required under the FERC Order, ATSI has recorded all merger transaction costs in FERC Account 426.5, Other Deductions for FERC reporting

---

[1] *FirstEnergy Corp., et al.*, 133 FERC ¶ 61,222 at P 73 (2010).

[2] *See, e.g., Midwest Power Systems, Inc. and Iowa-Illinois Gas and Electric Company*, 71 FERC ¶ 61,386, at 62,509 (1995); *MidAmerican Energy Company and MidAmerican Energy Holdings Company*, 85 FERC ¶ 61,354, at 62,370 (1998); *Wisconsin Electric Power Company,* 74 FERC ¶ 61,069, at 61,192 (1996).

[3] The Commission's accounting regulations provide for the classification of non-operating expenses in Accounts 426.1 through 426.5. The Note to the Special Instructions of these accounts states, "The classification of expenses as non-operating and their inclusion in these accounts is for accounting purposes. It does not preclude Commission consideration of proof to the contrary for ratemaking or other purposes."

[4] *See, e.g., Sierra Pacific Power Company and Nevada Power Company*, 87 FERC ¶ 61,077, at 61,335 (1999); *American Electric Power Company and Central and Southwest Corporation,* 85 FERC ¶ 61,201 at 61,822 (1998).

purposes. This required an adjustment that moved merger transaction costs from FERC Account 923, Outside Services, to FERC Account 426.5. This adjustment was reported as a reconciling item in the FERC Form No. 1 footnotes. As a result, Line 49 of ATSI’s 2010 FERC Form No. 1 Income Statement lists $2,722,406 of merger transaction costs in Account 426.5.

If you have any questions please let me know.