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PSEG

June 16, 2008

In the Matter of the Provision of
Basic Generation Service for Year Two of the Post-Transition Period
-and-
In the Matter of the Provision of
Basic Generation Service for the Period Beginning June 1, 2006
-and-
In the Matter of the Provision of
Basic Generation Service for the Period Beginning June 1, 2007
-and-
In the Matter of the Provision of
Basic Generation Service for the Period Beginning June 1, 2008

Docket Nos. EO03050394, EO05040317, EO06020119 and ER07060378

Kristi Izzo, Secretary
Board of Public Utilities
Two Gateway Center
Newark, New Jersey 07102

Dear Secretary Izzo:

This letter (original and 10 copies) is filed with the Board of Public Utilities (the "Board") on behalf of Atlantic City Electric Company ("ACE"), Jersey Central Power & Light Company ("JCP&L"), Public Service Electric and Gas Company ("PSE&G") and Rockland Electric Company ("RECO") (collectively, the "EDCs"). Enclosed please find copies of tariff sheets proposed by each of the EDCs and revised to reflect changes to the PJM Open Access Transmission Tariff ("OATT") made in response to a revised formula rate filing made by Trans-Allegheny Interstate Line Company ("TrAILCo") in connection with Federal Energy Regulatory Commission ("FERC") Docket No. ER07-562-000, and a filing made by Virginia Electric and Power Company ("VEPCo") in Docket Nos. ER-08-92-000 through ER-08-92-003.

In its Order dated October 22, 2003 (BPU Docket No. EO03050394), the Board authorized the EDCs to recover FERC-approved changes in firm transmission service-related charges. The Board has also authorized recovery of FERC-approved changes in firm transmission service-related charges in subsequent orders approving the Basic Generation

Service ("BGS") supply procurement process and the associated Supplier Master Agreement ("SMA"). In the most recent Board Order (BPU Docket No. ER07060378), the Board discussed this issue at length, and concluded that such a "pass through" of FERC-approved transmission rate changes was in the best interests of BGS customers.

The EDCs' pro-forma tariff sheets, included as Attachments 1 (ACE)[1], 2 (JCP&L)[2], 3 (PSE&G) and 4 (RECO), have proposed effective dates of September 1, 2008, and specifically reflect changes to BGS-FP and BGS-CIEP rates to customers resulting from the VEPCo filings that were approved by FERC on April 29, 2008, and the TrAILCo 2008 annual formula rate update filed with the FERC on May 15, 2008.[3] The specific, additional PJM transmission charges related to the TrAILCo and VEPCo filings are found in Schedule 12 of the PJM OATT.

These Schedule 12 charges, also defined as Transmission Enhancement Charges ("TECs") in the PJM OATT were implemented to compensate transmission owners for the annual transmission revenue requirements for "Required Transmission Enhancements" (again, as defined in the PJM OATT) that are requested by PJM for reliability or economic purposes. TECs are recovered by PJM through an additional transmission charge in the transmission zones assigned cost responsibility for Required Transmission Enhancement projects.

The EDCs request approval to implement these revised tariff rates effective September 1, 2008. In support of this request, the EDCs have included pro-forma tariff sheets in Attachments 1, 2, 3 and 4 of this filing. The BGS rates have been modified in accordance with the Board-approved methodology contained in each of the EDCs' Company-Specific Addenda (ACE at 12-13; JCP&L at 14 and 17; Public Service at 13-15: and RECO at 20-21) in the above-referenced BGS proceedings and in conformance with each of EDCs' Board-approved BGS tariff sheets.

In the event that the Board approves the implementation of this request either prior or subsequent to September 1, 2008, the EDCs will compress (or expand) the TEC costs related to the VEPCo project over the number of months remaining in 2008 and will compress (or expand) the TEC costs related to the TrAILCo project over the number of months remaining before June 2009. The TECs will be compressed using the rate translation methodology shown in Attachments 5 and 6. The EDCs will provide a compliance filing including updated versions of Attachments 1, 2, 3 and 4 for the Board's information reflecting differences in the timing of when these charges are authorized by the Board.

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[1] Please note that, in this submittal, ACE, in an effort to more clearly delineate the different TECs in the retail tariff, is presenting the TECs by project in table format in Rider BGS on Sheet 60b. The TEC line item on the individual Rate Schedules now refers to Rider BGS.

[2] In an effort to more clearly delineate the different TECs in the retail tariff, JCP&L renamed the first TEC for TRAILCO (effective February 1, 2008) as "TRAILCO1 - TEC", and the proposed TRAILCO TEC as "TRAILCO2 - TEC" in Riders BGS-FP and BGS-CIEP. Upon BPU approval of TRAILCO2 - TEC, JCP&L intends to remove TRAILCO1 from both Riders.

[3] TrAILCo's tariff on file with FERC specifies that, on or before May 15 of each year, TrAILCo shall recalculate its Annual Transmission Revenue Requirements producing the "Annual Update" for the upcoming Rate Year and post such Annual Update on PJM's Internet website via link to the Transmission Services page or a similar successor page. The EDCs received approval from the Board to begin allocating TECs related to the TrAILCo project in an Order dated January 18, 2008, but further ordered the EDCs to file for subsequent changes to Schedule 12.

The determinants for calculation of the PJM charges are set forth in Schedule 12 of the PJM OATT and on the Formula Rates page of the PJM website.[4] Attachment 5 shows the cost impact for the 2008/2009 period for each of the EDCs. These costs were allocated to the various transmission zones using the cost information from the formula rates for the TrAILCo and VEPCo projects posted on the PJM website. Please note that the cost allocations shares for PSE&G and JCP&L (7.23% and 4.36%, respectively) used in this filing are slightly lower than the cost allocation shares shown in the PJM OATT (7.58% and 4.57%). PJM has informed the EDCs that load serving entities will be billed the lower amounts in accordance with revised cost allocations filed by PJM and pending with FERC. The translation of the transmission zone rate impact to the BGS rates of each of the EDCs assuming implementation on September 1, 2008 is included as Attachment 6.

The EDCs also request that the BGS Suppliers be compensated for this increase, subject to the terms and conditions of the applicable SMAs. Any differences between payments to BGS Suppliers and charges to customers would flow through each EDC's BGS Reconciliation Charge. Since it is expected that the FERC-approved TEC for the VEPCo project will change in January of each year and may also change from time to time, the EDCs also respectfully request, in accordance with their Company-Specific Addenda in the above referenced proceedings, approval to submit compliance tariff sheets as required to implement any subsequent FERC-approved changes to the TECs resulting from the VEPCo project. The EDCs further request approval to submit compliance tariff sheets for future TEC changes related to the annual revenue requirements update filed with FERC for the TrAILCo project that are effective each June 1.

This filing satisfies the requirements of ¶¶ 15.9 (a)(i) and (ii) of the BGS-FP and BGS-CIEP SMAs, which mandate that BGS-FP and BGS-CIEP Suppliers be notified of rate increases for firm transmission service, and that the EDC file for and obtain Board approval of an increase in retail rates commensurate with the FERC-implemented rate increase.

We thank the Board for all courtesies extended.

Respectfully submitted,

Original Signed by
Frances I. Sundheim

Attachments

cc: Nusha Wyner
Frank Perrotti
Alice Bator
Michael McFadden
Stacy Peterson
Stefanie Brand, Division of Rate Counsel
Service List (via Electronic Mail Server)

[4] *See* http://www.pjm.com/services/formula-rates, Schedule 12 of the PJM Tariff.

Attachment 1

Atlantic City Electric Tariff Sheets

RATE SCHEDULE RS
(Residential Service)

AVAILABILITY
Available for full domestic service to individually metered residential customers, including rural domestic customers, engaged principally in agricultural pursuits.

	SUMMER June Through September	**WINTER** October Through May
Delivery Service Charges:		
Customer Charge ($/Month)	$2.51	$2.51
Distribution Rates ($/kWH)		
First Block	$0.028699	$0.028679
(Summer <= 750 kWh; Winter<= 500kWh)		
Excess kWh	$0.033030	$0.023190
Non-Utility Generation Charge (NGC) ($/kWH)	See Rider NGC	
Fossil Asset Sale Credit ($/kWh)	See Rider FASC	
Societal Benefits Charge ($/kWh)		
Consumer Education Program Charge	See Rider SBC	
Clean Energy Program	See Rider SBC	
Universal Service Fund	See Rider SBC	
Lifeline	See Rider SBC	
Uncollectible Accounts	See Rider SBC	
Regulatory Asset Recovery Charge (RARC) ($/kWh)	$0.000632	$0.000632
Transition Bond Charge (TBC) ($/kWh)	See Rider SEC	
Market Transition Charge Tax (MTC-Tax) ($/kWh)	See Rider SEC	
System Control Charge (SCC) ($/kWh)	See Rider BGS	
Transmission Service Charges ($/kWh):		
Transmission Rate	$0.007909	$0.007909
Reliability Must Run Transmission Surcharge	$0.000135	$0.000135
Transmission Enhancement Charge ($/kWh)	See Rider BGS	
Basic Generation Service Charge ($/kWh)	See Rider BGS	

TRANSITION ENERGY FACILITY ASSESSMENT (TEFA)
Energy charges (kWh) under this rate schedule shall be adjusted as set forth in Rider TEFA.

CORPORATE BUSINESS TAX (CBT)
Charges under this rate schedule include a component for Corporate Business Taxes as set forth in Rider CBT.

NEW JERSEY SALES AND USE TAX (SUT)
Charges under this rate schedule include a component for New Jersey Sales and Use Tax as set forth in Rider SUT.

RATE SCHEDULE MGS-SECONDARY

(Monthly General Service)

AVAILABILITY
Available at any point of Company's system where facilities of adequate character and capacity exist for the entire electric service requirements of any customer delivered at one point and metered at or compensated to the voltage of delivery. This schedule is not available to residential customers.

	SUMMER June Through September	WINTER October Through May
Delivery Service Charges:		
Customer Charge		
Single Phase	$4.80	$4.80
Three Phase	$6.00	$6.00
Distribution Demand Charge (for each kW in excess of 3 kW)	$4.62	$3.80
Reactive Demand Charge	$0.38	$0.38
(For each kvar over one-third of kW demand)		
Distribution Rates ($/kWh)		
For each of the first 300 kWh	$0.040026	$0.040096
For each of the next 900 kWh	$0.023417	$0.018400
For each additional kWh over 1,200 kWhs	$0.020568	$0.018400
Ceiling Limit	$0.044678	$0.044678
Non-Utility Generation Charge (NGC) ($/kWH)	See Rider NGC	
Fossil Asset Sale Credit ($/kWh)	See Rider FASC	
Societal Benefits Charge ($/kWh)		
Consumer Education Program Charge	See Rider SBC	
Clean Energy Program	See Rider SBC	
Universal Service Fund	See Rider SBC	
Lifeline	See Rider SBC	
Uncollectible Accounts	See Rider SBC	
Regulatory Assets Recovery Charge ($/kWh)	$0.000632	$0.000632
Transition Bond Charge (TBC) ($/kWh)	See Rider SEC	
Market Transition Charge Tax (MTC-Tax) ($/kWh)	See Rider SEC	
System Control Charge (SCC) ($/kWh)	See Rider BGS	
CIEP Standby Fee ($/kWh)	See Rider BGS	
Transmission Demand Charge ($/kW for each kW in excess of 3 kW)	$3.51	$3.13
Reliability Must Run Transmission Surcharge ($/kWh)	$0.000135	$0.000135
Transmission Enhancement Charge ($/kWh)	See Rider BGS	
Basic Generation Service Charge ($/kWh)	See Rider BGS	

The minimum monthly bill will be $4.80 per month plus any applicable adjustment.

TRANSITION ENERGY FACILITY ASSESSMENT (TEFA)
Energy charges (kWh) under this rate schedule shall be adjusted as set forth in Rider TEFA.

RATE SCHEDULE MGS-PRIMARY
(Monthly General Service)

AVAILABILITY

Available at any point of Company's system where facilities of adequate character and capacity exist for the entire electric service requirements of any customer delivered at one point and metered at or compensated to the voltage of delivery. This schedule is not available to residential customers.

	SUMMER	**WINTER**
	June Through September	October Through May
Delivery Service Charges:		
Customer Charge		
Single Phase	$4.80	$4.80
Three Phase	$6.00	$6.00
Distribution Demand Charge (for each kW in excess of 3 kW)	$4.81	$3.94
Reactive Demand Charge	$0.38	$0.38
(For each kvar over one-third of kW demand)		
Distribution Rates ($/kWh)		
For each of the first 300 kWh	$0.041288	$0.041359
For each of the next 900 kWh	$0.024410	$0.019311
For each additional kWh over 1,200 kWhs	$0.021515	$0.019311
Ceiling Limit	$0.046015	$0.046015
Non-Utility Generation Charge (NGC) ($/kWH)	See Rider NGC	
Fossil Asset Sale Credit ($/kWh)	See Rider FASC	
Societal Benefits Charge ($/kWh)		
Consumer Education Program Charge	See Rider SBC	
Clean Energy Program	See Rider SBC	
Universal Service Fund	See Rider SBC	
Lifeline	See Rider SBC	
Uncollectible Accounts	See Rider SBC	
Regulatory Assets Recovery Charge ($/kWh)	$0.000632	$0.000632
Transition Bond Charge (TBC) ($/kWh)	See Rider SEC	
Market Transition Charge Tax (MTC-Tax) ($/kWh)	See Rider SEC	
System Control Charge (SCC) ($/kWh)	See Rider BGS	
CIEP Standby Fee ($/kWh)	See Rider BGS	
Transmission Demand Charge ($/kW for each kW in excess of 3 kW)	$4.07	$3.72
Reliability Must Run Transmission Surcharge ($/kWh)	$0.000131	$0.000131
Transmission Enhancement Charge ($/kWh)	See Rider BGS	
Basic Generation Service Charge ($/kWh)	See Rider BGS	

The minimum monthly bill will be $4.80 per month plus any applicable adjustment.

TRANSITION ENERGY FACILITY ASSESSMENT (TEFA)

Energy charges (kWh) under this rate schedule shall be adjusted as set forth in Rider TEFA.

RATE SCHEDULE AGS-SECONDARY
(Annual General Service)

AVAILABILITY
Available at any point of Company's system where facilities of adequate character and capacity exist for the entire electric service requirements of any customer contracting for annual service delivered at one point and metered at or compensated to the voltage of delivery.

MONTHLY RATE

	SUMMER	**WINTER**
Delivery Service Charges:	June Through September	October Through May
Customer Charge	$93.33	$93.33
Distribution Demand Charge ($/kW)		
Including 25 kW	$5.34	$5.34
Per kW for the next 875 kW	$5.34	$5.34
Per kW for the next 9100 kW	$5.30	$5.30
Per kW for each additional kW	$4.96	$4.96
Winter Excess Demand*	N/A	$2.75
Reactive Demand (for each kvar over one-third of kW demand)	$0.47	$0.47
Distribution Rates ($/kWh)		
Step 1. For each of the first 82,500 kWh after determining Step 3	$0.000391	$0.000391
Step 2. For each additional kWh, except	$0.000355	$0.000355
Step 3. For each kWh over 330 kWh per kW demand	$0.000355	$0.000355
Non-Utility Generation Charge (NGC) ($/kWH)	See Rider NGC	
Fossil Asset Sale Credit ($/kWh)	See Rider FASC	
Societal Benefits Charge ($/kWh)		
Consumer Education Program Charge	See Rider SBC	
Clean Energy Program	See Rider SBC	
Universal Service Fund	See Rider SBC	
Lifeline	See Rider SBC	
Uncollectible Accounts	See Rider SBC	
Regulatory Assets Recovery Charge ($/kWh)	$0.000632	$0.000632
Transition Bond Charge (TBC) ($/kWh)	See Rider SEC	
Market Transition Charge Tax (MTC-Tax) ($/kWh)	See Rider SEC	
System Control Charge (SCC) ($/kWh)	See Rider BGS	
CIEP Standby Fee ($/kWh)	See Rider BGS	
Transmission Demand Charge ($/kW)		
Including 25 kW	$1.37	$1.37
Per kW for the next 875 kW	$1.37	$1.37
Per kW for the next 9100 kW	$1.37	$1.37
Per kW for each additional kW	$1.35	$1.35
Winter Excess Demand*	N/A	$0.84
Reliability Must Run Transmission Surcharge ($/kWh)	$0.000135	$0.000135
Transmission Enhancement Charge ($/kWh)	See Rider BGS	
Basic Generation Service Charge ($/kWh)	See Rider BGS	

*During the months October thru' May inclusive, for demand in excess of the metered demand recorded during the months June thru' September inclusive.

RATE SCHEDULE AGS-PRIMARY
(Annual General Service)

AVAILABILITY

Available at any point of Company's system where facilities of adequate character and capacity exist for the entire electric service requirements of any customer contracting for annual service delivered at one point and metered at or compensated to the voltage of delivery.

MONTHLY RATE

Delivery Service Charges:	SUMMER June Through September	WINTER October Through May
Customer Charge	$93.33	$93.33
Distribution Demand Charge ($/kW)		
Including 25 kW	$4.50	$4.50
Per kW for the next 875 kW	$4.50	$4.50
Per kW for the next 9100 kW	$4.47	$4.47
Per kW for each additional kW	$4.86	$4.86
Winter Excess Demand*	N/A	$2.50
Reactive Demand (for each kvar over one-third of kW demand)	$0.40	$0.40
Distribution Rates ($/kWh)		
Step 1. For each of the first 82,500 kWh after determining Step 3	$0.000843	$0.000843
Step 2. For each additional kWh, except	$0.000803	$0.000803
Step 3. For each kWh over 330 kWh per kW demand	$0.000803	$0.000803
Non-Utility Generation Charge (NGC) ($/kWH)	See Rider NGC	
Fossil Asset Sale Credit ($/kWh)	See Rider FASC	
Societal Benefits Charge ($/kWh)		
Consumer Education Program Charge	See Rider SBC	
Clean Energy Program	See Rider SBC	
Universal Service Fund	See Rider SBC	
Lifeline	See Rider SBC	
Uncollectible Accounts	See Rider SBC	
Regulatory Assets Recovery Charge ($/kWh)	$0.000632	$0.000632
Transition Bond Charge (TBC) ($/kWh)	See Rider SEC	
Market Transition Charge Tax (MTC-Tax) ($/kWh)	See Rider SEC	
System Control Charge (SCC) ($/kWh)	See Rider BGS	
CIEP Standby Fee ($/kWh)	See Rider BGS	
Transmission Demand Charge ($/kW)		
Including 25 kW	$1.57	$1.57
Per kW for the next 875 kW	$1.57	$1.57
Per kW for the next 9100 kW	$1.56	$1.56
Per kW for each additional kW	$1.53	$1.53
Winter Excess*	N/A	$0.84
Reliability Must Run Transmission Surcharge ($/kWh)	$0.000131	$0.000131
Transmission Enhancement Charge ($/kWh)	See Rider BGS	
Basic Generation Service Charge ($/kWh)	See Rider BGS	

***During the months October thru' May inclusive, for demand in excess of the metered demand recorded during the months June thru' September inclusive.

RATE SCHEDULE TGS

AVAILABILITY
Available at any point of Company's system where facilities of adequate character and capacity exist for the entire electric service requirements of any customer contracting for annual service delivered at one point and metered at or compensated to the voltage at transmission level (69 kV or higher) or subtransmission level (23 or 34.5 kV).

MONTHLY RATE

	SUMMER	**WINTER**
Delivery Service Charges:	June Through September	October Through May
Customer Charge	$89.26	$89.26
Distribution Demand Charge ($/kW)		
Including 25 kW	$1.89	$1.89
Per kW for the next 875 kW	$1.89	$1.89
Per kW for the next 9100 kW	$1.88	$1.88
Per kW for each additional kW	$1.86	$1.86
Winter Excess Demand*	N/A	$1.36
Reactive Demand (for each kvar over one-third of kW demand)	$0.17	$0.17
Distribution Rates ($/kWh)		
Step 1. For each of the first 82,500 kWh after determining Step 3	$0.000308	$0.000308
Step 2. For each additional kWh, except	$0.000295	$0.000295
Step 3. For each kWh over 330 kWh per kW demand	$0.000295	$0.000295
Non-Utility Generation Charge (NGC) ($/kWH)	See Rider NGC	
Fossil Asset Sale Credit ($/kWh)	See Rider FASC	
Societal Benefits Charge ($/kWh)		
Consumer Education Program Charge	See Rider SBC	
Clean Energy Program	See Rider SBC	
Universal Service Fund	See Rider SBC	
Lifeline	See Rider SBC	
Uncollectible Accounts	See Rider SBC	
Regulatory Assets Recovery Charge ($/kWh)	$0.000632	$0.000632
Transition Bond Charge (TBC) ($/kWh)	See Rider SEC	
Market Transition Charge Tax (MTC-Tax) ($/kWh)	See Rider SEC	
System Control Charge (SCC) ($/kWh)	See Rider BGS	
CIEP Standby Fee ($/kWh)	See Rider BGS	
Transmission Demand Charge ($/kW)		
Including 25 kW	$1.66	$1.66
Per kW for the next 875 kW	$1.66	$1.66
Per kW for the next 9100 kW	$1.65	$1.65
Per kW for each additional kW	$1.62	$1.62
Winter Excess Demand*	N/A	$.84
Reliability Must Run Transmission Surcharge ($/kWh)	$0.000128	$0.000128
Transmission Enhancement Charge ($/kWh)	See Rider BGS	
Basic Generation Service Charge ($/kWh)	See Rider BGS	

*During the months October through May inclusive, for demand in excess of the metered demand recorded during the months June thru' September inclusive.

RATE SCHEDULE DDC
(Direct Distribution Connection)

AVAILABILITY

Available at any point of the Company's existing distribution system where facilities of adequate character exist for the connection of fixed, constant and predictable non-residential loads not to exceed one kilowatt

T&D DAILY RATE

Service and Demand Charge:	$0.332251	Per day for each service connection plus
Energy Charge:	$4.271047	Per day for each kilowatt of effective load

The Service and Demand and Energy Charges includes the following charges:

Distribution:	
Service and Demand (per day per connection)	$0.332251
Energy (per day for each kW of effective load)	$1.600326
Non-Utility Generation Charge (NGC) ($/kWH)	See Rider NGC
Fossil Asset Sale Credit ($/kWh)	See Rider FASC
Societal Benefits Charge ($/kWh)	
Consumer Education Program Charge	See Rider SBC
Clean Energy Program	See Rider SBC
Universal Service Fund	See Rider SBC
Lifeline	See Rider SBC
Uncollectible Accounts	See Rider SBC
Regulatory Assets Recovery Charge ($/kWh)	$0.000632
Transition Bond Charge (TBC) ($/kWh)	See Rider SEC
Market Transition Charge Tax (MTC-Tax) ($/kWh)	See Rider SEC
System Control Charge (SCC) ($/kWh)	See Rider BGS
Transmission Rate ($/kWh)	$0.002612
Reliability Must Run Transmission Surcharge ($/kWh)	$0.000135
Transmission Enhancement Charge ($/kWh)	See Rider BGS
Basic Generation Service Charge ($/kWh)	See Rider BGS

TRANSITION ENERGY FACILITY ASSESSMENT (TEFA)

Energy charges (kWh) under this rate schedule shall be adjusted as set forth in Rider TEFA.

CORPORATE BUSINESS TAX (CBT)

Charges under this rate schedule include a component for Corporate Business Taxes as set forth in Rider CBT.

NEW JERSEY SALES AND USE TAX (SUT)

Charges under this rate schedule include a component for New Jersey Sales and Use Tax as set forth in Rider SUT.

LOAD CONSUMPTION

Effective load shall be determined by the Company and be specified in the contract. Effective load is defined as the sum of the products of the connected load in kilowatts times the percent load on at one time. No changes in attached load may be made by the customer without the permission of the Company and customer shall allow the Company access to his premises to assure conformance with this provision.

RATE SCHEDULE SPL
(Street and Private Lighting)

AVAILABILITY OF SERVICE

Available for general lighting service in service by December 14, 1982, new lights requested for installation before January 1, 1983 or high pressure sodium fixtures in the area served by the Company.

The Company will provide and maintain a lighting system and provide fixture and electric energy sufficient to operate said fixture continuously, automatically controlled, from approximately one-half hour after sunset until approximately one-half-hour before sunrise, every night and all night, approximately forty-two hundred (4200) hours per annum during the term of years hereinafter set forth.

The following rates shall be applied to the kWh Usage for the particular light type and size to determine the monthly charge per light.

Delivery Service Charges:	
Average Distribution Rate ($/kWh)	$0.135476
Non-Utility Generation Charge (NGC) ($/kWH)	See Rider NGC
Fossil Asset Sale Credit ($/kWh)	See Rider FASC
Societal Benefits Charge ($/kWh)	
Consumer Education Program Charge	See Rider SBC
Clean Energy Program	See Rider SBC
Universal Service Fund	See Rider SBC
Lifeline	See Rider SBC
Uncollectible Accounts	See Rider SBC
Regulatory Assets Recovery Charge ($/kWh)	$0.000632
Transition Bond Charge (TBC) ($/kWh)	See Rider SEC
System Control Charge (SCC) ($/kWh)	See Rider BGS
Market Transition Charge Tax (MTC-Tax) ($/kWh)	See Rider SEC
Transmission Rate ($/kWh)	$0.000000
Reliability Must Run Transmission Surcharge ($/kWh)	$0.000135
Transmission Enhancement Charge ($/kWh)	See Rider BGS
Basic Generation Service Charge ($/kWh)	See Rider BGS

RATE SCHEDULE CSL
(Contributed Street Lighting)

AVAILABILITY

Available for general lighting service in the service area of the Company

The Company will install and maintain a lighting system and provide electric energy sufficient to operate fixtures continuously, automatically controlled, for approximately one-half-hour after sunset until approximately one-half-hour before sunrise, every night and all night, approximately forty-two hundred (4200) hours per annum during the term of years hereinafter set forth. The installed cost of the fixtures, standards, and other installed equipment (if necessary) shall be paid by the customer upon installation. All equipment shall be the property of the Company (see Rate Schedule CLE). The rates below provide for ordinary maintenance and replacement of lamps and automatic controls. The rates below do not provide for replacement due to expiration of the service life of installed fixtures, standards or other equipment.

The following rates shall be applied to the kWh Usage for the particular light type and size to determine the monthly charge per light.

Delivery Service Charges:	
Average Distribution Rate ($/kWh)	$0.135476
Non-Utility Generation Charge (NGC) ($/kWH)	See Rider NGC
Fossil Asset Sale Credit ($/kWh)	See Rider FASC
Societal Benefits Charge ($/kWh)	
Consumer Education Program Charge	See Rider SBC
Clean Energy Program	See Rider SBC
Universal Service Fund	See Rider SBC
Lifeline	See Rider SBC
Uncollectible Accounts	See Rider SBC
Regulatory Assets Recovery Charge ($/kWh)	$0.000632
Transition Bond Charge (TBC) ($/kWh)	See Rider SEC
System Control Charge (SCC) ($/kWh)	See Rider BGS
Market Transition Charge Tax (MTC-Tax) ($/kWh)	See Rider SEC
Transmission Rate ($/kWh)	$0.000000
Reliability Must Run Transmission Surcharge ($/kWh)	$0.000135
Transmission Enhancement Charge ($/kWh)	See Rider BGS
Basic Generation Service Charge ($/kWh)	See Rider BGS

TRANSITION ENERGY FACILITY ASSESSMENT (TEFA)

Energy charges (kWh) under this rate schedule shall be adjusted as set forth in Rider TEFA.

CORPORATE BUSINESS TAX (CBT)

Charges under this rate schedule include a component for Corporate Business Taxes as set forth in Rider CBT.

NEW JERSEY SALES AND USE TAX (SUT)

Charges under this rate schedule include a component for New Jersey Sales and Use Tax as set forth in Rider SUT.

PRICE TO COMPARE

A customer may choose to receive electric supply from a third party supplier as defined in Section 11 of the Standard Terms and Conditions of this Tariff. A customer who receives electric supply from a third party supplier will not be billed the Basic Generation Service Charges or the Transmission Service Charges. . Customers who receive electric supply from a third party supplier will continue to be billed the System Control Charge (SCC) and, as applicable to customers eligible for BGS CIEP, the CIEP Standby Fee.

RIDER (BGS) continued

Basic Generation Service (BGS)

CIEP Standby Fee $0.000161 per kWh
This charge recovers the costs associated with the winning BGS-CIEP bidders maintaining the availability of the hourly priced default electric supply service plus administrative charges pursuant to N.J.S.A. 48:2-60 and New Jersey Sales and Use Tax as set forth in Rider SUT. This charge is assessed on all kWhs delivered to all CIEP- eligible customers on Rate Schedules MGS Secondary, MGS Primary, AGS Secondary, AGS Primary or TGS.

System Control Charge (SCC) $$0.000066 per kWh
This charge provides for recovery of appliance cycling load management costs. This charge includes administrative charges pursuant to N.J.S.A. 48:2-60 and New Jersey Sales and Use Tax as set forth in Rider SUT. This charge is assessed on all kWhs delivered to all electric customers.

Retail Margin $0.005377 per kWh
This charge is applicable to all customers taking service under BGS CIEP and those BGS-FP customers on Rate Schedules MGS Secondary, MGS Primary, AGS Secondary or AGS Primary whose annual PLS for generation capacity is equal to or greater than 750 kW as of November 1 of each year. This charge includes administrative charges pursuant to N.J.S.A. 48:2-60 and New Jersey Sales and Use Tax as set forth in Rider SUT

Transmission Enhancement Charge
This charge reflects Transmission Enhancement Charges (“TECs”), implemented to compensate transmission owners for the annual transmission revenue requirements for “Required Transmission Enhancements” (as defined in Schedule 12 of the PJM OATT) that are requested by PJM for reliability or economic purposes and approved by the Federal Energy Regulatory Commission (FERC). The TEC charge (in $ per kWh by Rate Schedule), including administrative charges pursuant to N.J.S.A. 48:2-60 and New Jersey Sales and Use Tax as set forth in Rider SUT, is delineated in the following table.

Rate Class	PATH	TrAILCo	Dominion	Total
RS	$ 0.000061	$ 0.000120	$ 0.000018	$ 0.000199
MGS Secondary	$ 0.000054	$ 0.000122	$ 0.000018	$ 0.000194
MGS Primary	$ 0.000050	$ 0.000207	$ 0.000022	$ 0.000279
AGS Secondary	$ 0.000042	$ 0.000093	$ 0.000014	$ 0.000149
AGS Primary	$ 0.000042	$ 0.000108	$ 0.000017	$ 0.000167
TGS	$ 0.000083	$ 0.000174	$ 0.000026	$ 0.000283
SPL/CSL	$ 0.000000	$ 0.000000	$ 0.000000	$ 0.000000
DDC	$ 0.000028	$ 0.000056	$ 0.000009	$ 0.000093

Attachment 2

Jersey Central Power and Light Tariff Sheets

Rider BGS-FP
Basic Generation Service – Fixed Pricing
(Applicable to Service Classifications RS, RT, RGT, GS, GST, OL, SVL, MVL and ISL)

1) BGS Energy Charge per KWH: (Continued)

(Note 1) Retail Margin: A Retail Margin of **$0.005350** per KWH (includes Sales and Use Tax as provided in Rider SUT) will be added to the BGS Energy Charges stated above applicable to all KWH usage by any GS and GST customers that the Company has identified with loads of 750 KW or greater (but less than 1000 KW) as of November 1, 2007 and that the Company has notified that the Retail Margin would be added to the BGS Energy Charges applicable to their KWH usage beginning June 1, 2008.

2) BGS Transmission Charge per KWH: As provided in the respective tariff for Service Classifications RS, RT, RGT, GS, GST, OL, SVL, MVL and ISL. Effective January 1, 2008, a RMR surcharge of **$0.000111** per KWH (includes Sales and Use Tax as provided in Rider SUT) will be added to the BGS Transmission Charge applicable to all KWH usage.

Effective February 1, 2008, a TRAILCO1-TEC surcharge of **$0.000022** per KWH (includes Sales and Use Tax as provided in Rider SUT) will be added to the BGS Transmission Charge applicable to all KWH usage except lighting under Service Classifications OL, SVL, MVL and ISL.

Effective September 1, 2008, a VEPCO-TEC surcharge of **$0.000021** per KWH (includes Sales and Use Tax as provided in Rider SUT) will be added to the BGS Transmission Charge applicable to all KWH usage except lighting under Service Classifications OL, SVL, MVL and ISL.

3) BGS Reconciliation Charge per KWH: ($0.002832) (includes Sales and Use Tax as provided in Rider SUT)

The above BGS Reconciliation Charge recovers the difference between the payments to BGS suppliers and the revenues from BGS customers for Basic Generation Service and is subject to quarterly true-up.

Rider BGS-CIEP
Basic Generation Service – Commercial Industrial Energy Pricing
(Applicable to Service Classifications GP and GT and Certain Customers under Service Classifications GS and GST)

AVAILABILITY: Rider BGS-CIEP is available to and provides Basic Generation Service (default service) charges applicable to all Full Service Customers taking service at primary and transmission voltages under Service Classifications GP and GT and any Full Service Customers taking service at secondary voltages under Service Classifications GS and GST that have a peak load share of 1000 KW or greater as of November 1, 2007, or that have elected to take BGS-CIEP service no later than the second business day in January of each year. All BGS-CIEP customers remain subject to this Rider for the entire 12-month period from June 1 of any given year through May 31 of the following year.

RATE PER BILLING MONTH:
(For service rendered effective June 1, 2008 through May 31, 2009)

1) BGS Energy Charge per KWH: The sum of actual real-time PJM load weighted average Locational Marginal Price for JCP&L Transmission Zone and ancillary services of **$0.00600** per KWH, times the Losses Multiplier provided below, plus a Retail Margin of **$0.005** per KWH, times 1.07 multiplier for Sales and Use Tax as provided in Rider SUT.

Losses Multiplier:	GT – High Tension Service	1.005
	GT	1.027
	GP	1.047
	GST	1.103
	GS	1.103

2) BGS Capacity Charge per KW of Generation Obligation: $0.11576 per KW-day times BGS-CIEP customer's share of the capacity peak load assigned to the JCP&L Transmission Zone by the PJM Interconnection, L.L.C., as adjusted by PJM assigned capacity related factors, times 1.07 multiplier for Sales and Use Tax as provided in Rider SUT.

3) BGS Transmission Charge per KWH: As provided in the respective tariff for Service Classifications GS, GST, GP and GT. Effective January 1, 2008, a RMR surcharge will be added to the BGS Transmission Charge applicable to all KWH usage, as follows (includes Sales and Use Tax as provided in Rider SUT):

GT – High Tension Service	**$0.000102**
GT	**$0.000104**
GP	**$0.000106**
GS and GST	**$0.000111**

Effective February 1, 2008, a TRAILCO1-TEC surcharge will be added to the BGS Transmission Charge applicable to all KWH usage, as follows (includes Sales and Use Tax as provided in Rider SUT):

GT – High Tension Service	**$0.000004**
GT	**$0.000012**
GP	**$0.000013**
GS and GST	**$0.000022**

Effective September 1, 2008, a VEPCO-TEC surcharge will be added to the BGS Transmission Charge applicable to all KWH usage, as follows (includes Sales and Use Tax as provided in Rider SUT):

GT – High Tension Service	**$0.000003**
GT	**$0.000011**
GP	**$0.000012**
GS and GST	**$0.000021**

4) BGS Reconciliation Charge per KWH: ($0.000039) (includes Sales and Use Tax as provided in Rider SUT)

The above BGS Reconciliation Charge recovers the difference between the payments to BGS suppliers and the revenues from BGS customers for Basic Generation Service and is subject to quarterly true-up.

Filed pursuant to Order of Board of Public Utilities
Docket Nos. EO03050394, EO05040317, EO06020119 and ER07060378 dated

Issued by Stephen E. Morgan, President
300 Madison Avenue, Morristown, NJ 07962-1911

Rider BGS-FP
Basic Generation Service – Fixed Pricing
(Applicable to Service Classifications RS, RT, RGT, GS, GST, OL, SVL, MVL and ISL)

1) BGS Energy Charge per KWH: (Continued)

(Note 1) Retail Margin: A Retail Margin of **$0.005350** per KWH (includes Sales and Use Tax as provided in Rider SUT) will be added to the BGS Energy Charges stated above applicable to all KWH usage by any GS and GST customers that the Company has identified with loads of 750 KW or greater (but less than 1000 KW) as of November 1, 2007 and that the Company has notified that the Retail Margin would be added to the BGS Energy Charges applicable to their KWH usage beginning June 1, 2008.

2) BGS Transmission Charge per KWH: As provided in the respective tariff for Service Classifications RS, RT, RGT, GS, GST, OL, SVL, MVL and ISL. Effective January 1, 2008, a RMR surcharge of **$0.000111** per KWH (includes Sales and Use Tax as provided in Rider SUT) will be added to the BGS Transmission Charge applicable to all KWH usage.

Effective February 1, 2008, a TRAILCO1-TEC surcharge of **$0.000022** per KWH (includes Sales and Use Tax as provided in Rider SUT) will be added to the BGS Transmission Charge applicable to all KWH usage except lighting under Service Classifications OL, SVL, MVL and ISL.

Effective September 1, 2008, a TRAILCO2-TEC surcharge of **$0.000101** per KWH (includes Sales and Use Tax as provided in Rider SUT) will be added to the BGS Transmission Charge applicable to all KWH usage except lighting under Service Classifications OL, SVL, MVL and ISL.

3) BGS Reconciliation Charge per KWH: ($0.002832) (includes Sales and Use Tax as provided in Rider SUT)

The above BGS Reconciliation Charge recovers the difference between the payments to BGS suppliers and the revenues from BGS customers for Basic Generation Service and is subject to quarterly true-up.

Rider BGS-CIEP
Basic Generation Service – Commercial Industrial Energy Pricing
(Applicable to Service Classifications GP and GT and Certain Customers under Service Classifications GS and GST)

AVAILABILITY: Rider BGS-CIEP is available to and provides Basic Generation Service (default service) charges applicable to all Full Service Customers taking service at primary and transmission voltages under Service Classifications GP and GT and any Full Service Customers taking service at secondary voltages under Service Classifications GS and GST that have a peak load share of 1000 KW or greater as of November 1, 2007, or that have elected to take BGS-CIEP service no later than the second business day in January of each year. All BGS-CIEP customers remain subject to this Rider for the entire 12-month period from June 1 of any given year through May 31 of the following year.

RATE PER BILLING MONTH:
(For service rendered effective June 1, 2008 through May 31, 2009)

1) BGS Energy Charge per KWH: The sum of actual real-time PJM load weighted average Locational Marginal Price for JCP&L Transmission Zone and ancillary services of **$0.00600** per KWH, times the Losses Multiplier provided below, plus a Retail Margin of **$0.005** per KWH, times 1.07 multiplier for Sales and Use Tax as provided in Rider SUT.

Losses Multiplier:	GT – High Tension Service	1.005
	GT	1.027
	GP	1.047
	GST	1.103
	GS	1.103

2) BGS Capacity Charge per KW of Generation Obligation: $0.11576 per KW-day times BGS-CIEP customer's share of the capacity peak load assigned to the JCP&L Transmission Zone by the PJM Interconnection, L.L.C., as adjusted by PJM assigned capacity related factors, times 1.07 multiplier for Sales and Use Tax as provided in Rider SUT.

3) BGS Transmission Charge per KWH: As provided in the respective tariff for Service Classifications GS, GST, GP and GT. Effective January 1, 2008, a RMR surcharge will be added to the BGS Transmission Charge applicable to all KWH usage, as follows (includes Sales and Use Tax as provided in Rider SUT):

GT – High Tension Service	**$0.000102**
GT	**$0.000104**
GP	**$0.000106**
GS and GST	**$0.000111**

Effective February 1, 2008, a TRAILCO1-TEC surcharge will be added to the BGS Transmission Charge applicable to all KWH usage, as follows (includes Sales and Use Tax as provided in Rider SUT):

GT – High Tension Service	**$0.000004**
GT	**$0.000012**
GP	**$0.000013**
GS and GST	**$0.000022**

Effective September 1, 2008, a TRAILCO2-TEC surcharge will be added to the BGS Transmission Charge applicable to all KWH usage, as follows (includes Sales and Use Tax as provided in Rider SUT):

GT – High Tension Service	**$0.000014**
GT	**$0.000052**
GP	**$0.000056**
GS and GST	**$0.000101**

4) BGS Reconciliation Charge per KWH: ($0.000039) (includes Sales and Use Tax as provided in Rider SUT)

The above BGS Reconciliation Charge recovers the difference between the payments to BGS suppliers and the revenues from BGS customers for Basic Generation Service and is subject to quarterly true-up.

Filed pursuant to Order of Board of Public Utilities
Docket Nos. EO03050394, EO05040317, EO06020119 and ER07060378 dated

Issued by Stephen E. Morgan, President
300 Madison Avenue, Morristown, NJ 07962-1911

Attachment 3

Public Service Electric and Gas Company Tariff Sheets

BASIC GENERATION SERVICE – FIXED PRICING (BGS-FP)
ELECTRIC SUPPLY CHARGES

APPLICABLE TO:

Default electric supply service for Rate Schedules RS, RSP, RHS, RLM, WH, WHS, HS, BPL, BPL-POF, PSAL, GLP and LPL-Secondary (less than 1,000 kilowatts).

BGS ENERGY CHARGES:

Applicable to Rate Schedules RS, RHS, RLM, WH, WHS, HS, BPL, BPL-POF and PSAL

Charges per kilowatthour:

Rate Schedule	For usage in each of the months of October through May		For usage in each of the months of June through September	
	Charges	Charges Including SUT	Charges	Charges Including SUT
RS – first 600 kWh	10.8319 ¢	11.5901 ¢	12.1609 ¢	13.0122 ¢
RS – in excess of 600 kWh	10.8319 ¢	11.5901 ¢	13.0629 ¢	13.9773 ¢
RHS – first 600 kWh	9.7280 ¢	10.4090 ¢	12.0863 ¢	12.9323 ¢
RHS – in excess of 600 kWh	9.7280 ¢	10.4090 ¢	13.2924 ¢	14.2229 ¢
RLM On-Peak	15.1178 ¢	16.1760 ¢	16.8787 ¢	18.0602 ¢
RLM Off-Peak	7.2831 ¢	7.7929 ¢	8.1912 ¢	8.7646 ¢
WH	8.1185 ¢	8.6868 ¢	9.7328 ¢	10.4141 ¢
WHS	7.9564 ¢	8.5133 ¢	9.4606 ¢	10.1228 ¢
HS	9.7068 ¢	10.3863 ¢	13.9197 ¢	14.8941 ¢
BPL	7.4192 ¢	7.9385 ¢	8.3501 ¢	8.9346 ¢
BPL-POF	7.4192 ¢	7.9385 ¢	8.3501 ¢	8.9346 ¢
PSAL	7.4192 ¢	7.9385 ¢	8.3501 ¢	8.9346 ¢

The above Basic Generation Service Energy Charges reflect costs for Energy, Generation Capacity, Transmission, and Ancillary Services (including PJM Interconnection, L.L.C. (PJM) Administrative Charges). The portion of these charges related to Network Integration Transmission Service, including the PJM Seams Elimination Cost Assignment Charges, the PJM Reliability Must Run Charge and PJM Transmission Enhancement Charges may be changed from time to time on the effective date of such change to the PJM rate for these charges as approved by the Federal Energy Regulatory Commission (FERC).

Kilowatt threshold noted above is based upon the customer’s Peak Load Share of the overall summer peak load assigned to Public Service by the Pennsylvania-New Jersey-Maryland Office of the Interconnection (PJM). See Section 9.1, Measurement of Electric Service, of the Standard Terms and Conditions of this Tariff.

BASIC GENERATION SERVICE – FIXED PRICING (BGS-FP)
ELECTRIC SUPPLY CHARGES
(Continued)

BGS CAPACITY CHARGES:

Applicable to Rate Schedules GLP and LPL-Sec.

Charges per kilowatt of Generation Obligation:

Charge applicable in the months of June through September..$ 4.3771
Charge including New Jersey Sales and Use Tax (SUT) ....$ 4.6835

Charge applicable in the months of October through May..$ 4.3591
Charge including New Jersey Sales and Use Tax (SUT) ....$ 4.6642

The above charges shall recover each customer's share of the overall summer peak load assigned to the Public Service Transmission Zone by the PJM Interconnection, L.L.C. (PJM) as adjusted by PJM assigned capacity related factors and shall be in accordance with Section 9.1, Measurement of Electric Service, of the Standard Terms and Conditions.

BGS TRANSMISSION CHARGES

Applicable to Rate Schedules GLP and LPL-Sec.

Charges per kilowatt of Transmission Obligation:

Currently effective Annual Transmission Rate for
Network Integration Transmission Service for the
Public Service Transmission Zone as stated in the
FERC Electric Tariff of the PJM Interconnection, LLC ....$ 17,631 per MW per year
PJM Seams Elimination Cost Assignment Charges ....$ 0.00 per MW per month
PJM Reliability Must Run Charge..$ 38.50 per MW per month
PJM Transmission Enhancements
Trans-Allegheny Interstate Line Company
Projects – 2008 Annual Update ....$ 24.26 per MW per month
Virginia Electric and Power Company Projects..............................$ 5.97 per MW per month

Above rates converted to a charge per kW of Transmission
Obligation, applicable in all months..$ 1.5381
Charge including New Jersey Sales and Use Tax (SUT) ....$ 1.6458

The above charges shall recover each customer's share of the overall summer peak transmission load assigned to the Public Service Transmission Zone by the PJM Interconnection, L.L.C. (PJM) as adjusted by PJM assigned transmission capacity related factors and shall be in accordance with Section 9.1, Measurement of Electric Service, of the Standard Terms and Conditions. These charges will be changed from time to time on the effective date of such change to the PJM rate for charges for Network Integration Transmission Service, including the PJM Seams Elimination Cost Assignment Charges, the PJM Reliability Must Run Charge and PJM Transmission Enhancement Charges as approved by Federal Energy Regulatory Commission (FERC).

BASIC GENERATION SERVICE – COMMERCIAL AND INDUSTRIAL ENERGY PRICING (CIEP)
ELECTRIC SUPPLY CHARGES
(Continued)

BGS TRANSMISSION CHARGES

Charges per kilowatt of Transmission Obligation:

Currently effective Annual Transmission Rate for
Network Integration Transmission Service for the
Public Service Transmission Zone as stated in the
FERC Electric Tariff of the PJM Interconnection, LLC .... $ 17,631 per MW per year
PJM Seams Elimination Cost Assignment Charges .... $ 0.00 per MW per month
PJM Reliability Must Run Charge.. $ 38.50 per MW per month
PJM Transmission Enhancements
Trans-Allegheny Interstate Line Company
Projects – 2008 Annual Update .... $ 24.26 per MW per month
Virginia Electric and Power Company Projects.............................. $ 5.97 per MW per month

Above rates converted to a charge per kW of Transmission
Obligation, applicable in all months... $ 1.5381
Charge including New Jersey Sales and Use Tax (SUT) $1.6458

The above charges shall recover each customer's share of the overall summer peak transmission load assigned to the Public Service Transmission Zone by the PJM Interconnection, L.L.C. (PJM) as adjusted by PJM assigned transmission capacity related factors and shall be in accordance with Section 9.1, Measurement of Electric Service, of the Standard Terms and Conditions. These charges will be changed from time to time on the effective date of such charge to the PJM rate for charges for Network Integration Transmission Service, including the PJM Seams Elimination Cost Assignment Charges, the PJM Reliability Must Run Charge and PJM Transmission Enhancement Charges as approved by Federal Energy Regulatory Commission (FERC).

Kilowatt threshold noted above is based upon the customer's Peak Load Share of the overall summer peak load assigned to Public Service by the Pennsylvania-New Jersey-Maryland Office of the Interconnection (PJM). See Section 9.1, Measurement of Electric Service, of the Standard Terms and Conditions of this Tariff.

Attachment 4
Rockland Electric Company Tariff Sheets

SERVICE CLASSIFICATION NO. 1
RESIDENTIAL SERVICE (Continued)

RATE – SIX PART – MONTHLY: (Continued)

(3) Transmission Charge

A. These charges apply to all customers taking Basic Generation Service from the Company. These charges are also applicable to customers located in the Company's Central and Western Divisions and obtaining Competitive Energy Supply. These charges are not applicable to customers located in the Company's Eastern Division and obtaining Competitive Energy Supply. The Company's Eastern, Central and Western Divisions are defined in General Information Section No. 1.

	Summer Months*	Other Months
First 250 kWh………………@	1.209 ¢ per kWh	1.209 ¢ per kWh
Over 250 kWh………………@	1.209 ¢ per kWh	1.209 ¢ per kWh

B. Transmission Surcharge – This charge is applicable to all customers taking Basic Generation Service from the Company and includes surcharges related to Reliability Must Run and Transmission Enhancement Charges.

All kWh	0.022 ¢ per kWh	0.022 ¢ per kWh

(4) Societal Benefits Charge

In accordance with General Information Section 29, a Societal Benefits Charge shall be assessed on all kWh delivered hereunder.

(5) Securitization Charges

In accordance with General Information Section 32, the Securitization Charges shall be assessed on all kWh delivered hereunder.

(6) Basic Generation Service

Customers taking Basic Generation Service from the Company will be billed for such service in accordance with General Information Section No. 28.

* Definition of Summer Billing Months
June through September

(Continued)

SERVICE CLASSIFICATION NO. 2
GENERAL SERVICE (Continued)

RATE – SIX PART – MONTHLY: (Continued)

(2) Distribution Charges (Continued)

	Summer Months*	Other Months
Primary Voltage Service Only Over 60,000 kWh or 300 hours use of demand, whichever is greater.................................@	1.348 ¢ per kWh	1.348 ¢ per kWh

(3) Transmission Charges

A. These charges apply to all customers taking Basic Generation Service from the Company. These charges are also applicable to customers located in the Company's Central and Western Divisions and obtaining Competitive Energy Supply. These charges are not applicable to customers located in the Company's Eastern Division and obtaining Competitive Energy Supply. The Company's Eastern, Central and Western Divisions are defined in General Information Section No. 1.

	Summer Months*	Other Months
Demand Charge		
First 5 kW or less…………..@	No Charge	No Charge
Over 5 kW…………………..@	$1.38 per kW	$1.19 per kW
Usage Charge		
First 4,920 kWh…………….@	0.552 ¢ per kWh	0.552 ¢ per kWh
Over 4,920 kWh……………@	0.552 ¢ per kWh	0.552 ¢ per kWh
Primary Voltage Service Only Over 60,000 kWh or 300 hours use of demand, whichever is greater ……………………...@	0.552 ¢ per kWh	0.552 ¢ per kWh

B. Transmission Surcharge – This charge is applicable to all customers taking Basic Generation Service from the Company and includes surcharges related to Reliability Must Run and Transmission Enhancement Charges.

Secondary Voltage Service Only All kWh	0.017 ¢ per kWh	0.017 ¢ per kWh
Primary Voltage Service Only All kWh	0.014 ¢ per kWh	0.014 ¢ per kWh

(Continued)

SERVICE CLASSIFICATION NO. 3
RESIDENTIAL TIME-OF-DAY HEATING SERVICE (Continued)

RATE – SIX PART – MONTHLY: (Continued)

(3) Transmission Charge (Continued)
A. (Continued)

	Summer Months*	Other Months
Peak All kWh measured between 10:00 a.m. and 10:00 p.m., Monday through Friday.........................@	0.811 ¢ per kWh	0.811 ¢ per kWh
Off-Peak: All other kWh..........................@	0.811 ¢ per kWh	0.811 ¢ per kWh

B. Transmission Surcharge – This charge is applicable to all customers taking Basic Generation Service from the Company and includes surcharges related to Reliability Must Run and Transmission Enhancement Charges.

	Summer Months*	Other Months
All kWh..................................@	0.020 ¢ per kWh	0.020 ¢ per kWh

(4) Societal Benefits Charge

In accordance with General Information Section 29, a Societal Benefits Charge shall be assessed on all kWh delivered hereunder.

(5) Securitization Charges

In accordance with General Information Section 32, the Securitization Charges shall be assessed on all kWh delivered hereunder.

(6) Basic Generation Service

Customers taking Basic Generation Service from the Company will be billed for such service in accordance with General Information Section No. 28.

In accordance with Riders CBT, SUT and TEFA, the charges in this Rate Schedule include provision for the New Jersey Corporation Business Tax, the New Jersey Sales and Use Tax, and until it expires, a temporary Transitional Energy Facility Assessment. When billed to customers exempt from one or more of these taxes, as set forth in Riders CBT, SUT and TEFA, such charges will be reduced by the relevant amount of such taxes included therein.

* Definition of Summer Billing Months
June through September

(Continued)

SERVICE CLASSIFICATION NO. 5
RESIDENTIAL SPACE HEATING SERVICE (Continued)

RATE – SIX PART – MONTHLY: (Continued)

(3) Transmission Charge

A. These charges apply to all customers taking Basic Generation Service from the Company. These charges are also applicable to customers located in the Company's Central and Western Divisions and obtaining Competitive Energy Supply. These charges are not applicable to customers located in the Company's Eastern Division and obtaining Competitive Energy Supply. The Company's Eastern, Central and Western Divisions are defined in General Information Section No. 1.

	Summer Months*		Other Months	
First 250 kWh ....@	0.794	¢ per kWh	0.794	¢ per kWh
Next 450 kWh ....@	0.794	¢ per kWh	0.794	¢ per kWh
Over 700 kWh ....@	0.794	¢ per kWh	0.794	¢ per kWh

B. Transmission Surcharge – This charge is applicable to all customers taking Basic Generation Service from the Company and includes surcharges related to Reliability Must Run and Transmission Enhancement Charges.

All kWh ....@	0.015	¢ per kWh	0.015	¢ per kWh

(4) Societal Benefits Charge

In accordance with General Information Section 29, a Societal Benefits Charge shall be assessed on all kWh delivered hereunder.

(5) Securitization Charges

In accordance with General Information Section 32, the Securitization Charges shall be assessed on all kWh delivered hereunder.

(6) Basic Generation Service

Customers taking Basic Generation Service from the Company will be billed for such service in accordance with General Information Section No. 28.

In accordance with Riders CBT, SUT and TEFA, the charges in this Rate Schedule include provision for the New Jersey Corporation Business Tax, the New Jersey Sales and Use Tax, and until it expires, a temporary Transitional Energy Facility Assessment. When billed to customers exempt from one or more of these taxes, as set forth in Riders CBT, SUT and TEFA, such charges will be reduced by the relevant amount of such taxes included therein.

* Definition of Summer Billing Months
June through September

(Continued)

SERVICE CLASSIFICATION NO. 7
LARGE GENERAL TIME-OF-DAY SERVICE (Continued)

RATE – SEVEN PART – MONTHLY: (Continued)

(2) Distribution Charges (Continued)

Usage Charge

Period I	All kWh @	1.764 ¢ per kWh
Period II	All kWh @	1.388 ¢ per kWh
Period III	All kWh @	1.764 ¢ per kWh
Period IV	All kWh @	1.388 ¢ per kWh

(3) Transmission Charges

A. These charges apply to all customers taking Basic Generation Service from the Company. These charges are also applicable to customers located in the Company's Central and Western Divisions and obtaining Competitive Energy Supply. These charges are not applicable to customers located in the Company's Eastern Division and obtaining Competitive Energy Supply. The Company's Eastern, Central and Western Divisions are defined in General Information Section No. 1.

Demand Charge

Period I	All kW @	$1.92 per kW
Period II	All kW @	$0.50 per kW
Period III	All kW @	$1.74 per kW
Period IV	All kW @	$0.50 per kW

Usage Charge

Period I	All kWh @	0.366 ¢ per kWh
Period II	All kWh @	0.366 ¢ per kWh
Period III	All kWh @	0.366 ¢ per kWh
Period IV	All kWh @	0.366 ¢ per kWh

B. Transmission Surcharge – This charge is applicable to all customers taking Basic Generation Service from the Company and includes surcharges related to Reliability Must Run and Transmission Enhancement Charges.

All Periods	All kWh @	0.015 ¢ per kWh

(Continued)

Attachment 5a
Cost Allocation of 2008 VEPCo Schedule 12 Charges

Attachment 5b
Cost Allocation of 2008/2009 TrAILCo Schedule 12 Charges

Attachment 5a-PJM Schedule 12 - Transmission Enhancement Charges for January 2008 - December 2008
Calculation of costs and monthly PJM charges for VEPCo Projects

		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
			Responsible Customers - Schedule 12 Appendix				Estimated New Jersey EDC Zone Charges by Project				
Required Transmission Enhancement *per PJM website*	**PJM Upgrade ID** *per PJM spreadsheet*	**Jan - Dec 2008 Annual Revenue Requirement** *per PJM website*	**ACE Zone Share**	**JCP&L Zone Share[1]**	**PSE&G Zone Share[1]**	**RE Zone Share**	**ACE Zone Charges**	**JCP&L Zone Charges**	**PSE&G Zone Charges**	**RE Zone Charges**	**Total NJ Zones Charges**
			per PJM Open Access Transmission Tariff								
Mt Storm - Doubs 500kV	b0217	$ 347,423.00	2.05%	4.36%	7.23%	0.30%	$7,122	$15,148	$25,119	$1,042	$48,431
Loudoun 150 MVA cap @ 500 kV	b0222	$ 303,849.00	2.05%	4.36%	7.23%	0.30%	$6,229	$13,248	$21,968	$912	$42,357
Ashburn/Dranesville 150 MVA cap @ 230 kV	b0223, b0224	$ 388,741.00	0.00%	6.00%	10.00%	0.00%	$0	$23,324	$38,874	$0	$62,199
Possum Pt. 33 MVA cap @ 115KV	b0225	$ 155,835.00	0.00%	0.00%	13.00%	0.00%	$0	$0	$20,259	$0	$20,259
Clfiton 500/230 kVA Tx & 150 MVAR cap	b0226	$ 1,583,884.00	1.00%	2.00%	4.00%	0.00%	$15,839	$31,678	$63,355	$0	$110,872
Northern Neck Brkr	b0341	$ 372,873.00	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
Dooms 500/230 kVa Tx	b0403	$ 1,567,125.00	1.00%	3.00%	5.00%	0.00%	$15,671	$47,014	$78,356	$0	$141,041
Totals		**$ 4,719,730.00**					**$44,861**	**$130,411**	**$247,931**	**$1,954**	**$425,158**
Notes on calculations >>>							= (a) * (b)	= (a) * (c)	= (a) * (d)	= (a) * (e)	= (f) + (g) + (h) + (i)

	(k)	(l)	(m)	(n)	(o)
Zonal Cost Allocation for New Jersey Zones	**Average Monthly Impact on Zone Customers in 2008**	**2007 TX Peak Load** *per PJM website*	**Rate in $/MW-mo.**	**2008 Impact[4] (4 months)**	
PSE&G	$ 61,982.81	10,378.7	$ 5.97	$ 247,931	
JCP&L	$ 32,602.84	6,256.3	$ 5.21	$ 130,411	
ACE	$ 11,215.29	2,947.0	$ 3.81	$ 44,861	
RE	$ 488.45	423.0	$ 1.15	$ 1,954	
Total Impact on NJ Zones	**$ 106,289.39**			**$ 425,158**	
Notes on calculations >>>			= (k) * (l)	= (k) *4	

Notes:
1) 2008 allocation share percentages (columns e,f) were filed with FERC and are still pending - PJM uses revised percentages for billing purposes, but OATT still shows higher percentages.
The values used in this filing represents lower allocations (and costs).
2) PJM Settlement for "Below 500kV" filed in September 2007 FERC and still pending.
3) Allocation share percentages for Merchant Transmission Owners pending an ALJ decision after hearing which could affect all other allocation share percentages (columns b-d above - past, present and future).
4) Rate compression assumes BPU approves rate for implementation on September 1, 2008.

Attachment 5b -PJM Schedule 12 - Transmission Enhancement Charges for June 2008 - May 2009
Calculation of costs and monthly PJM charges for Allegheny TrAILCo Projects

		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
			Responsible Customers - Schedule 12 Appendix				**Estimated New Jersey EDC Zone Charges by Project**				
Required Transmission Enhancement *per PJM website*	**PJM Upgrade ID** *per PJM spreadsheet*	**June 2008- May 2009 Annual Revenue Requirement** *per PJM website*	**ACE Zone Share**	**JCP&L Zone Share[1]**	**PSE&G Zone Share[1]**	**RE Zone Share**	**ACE Zone Charges**	**JCP&L Zone Charges**	**PSE&G Zone Charges**	**RE Zone Charges**	**Total NJ Zones Charges**
			per PJM Open Access Transmission Tariff								
Prexy - 502 Junction (<500kV) - CWIP	b0321.2; b0321.3	$ 2,368,355.65	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
Prexy - 502 Junction (>=500kV) - CWIP[1]	b0321.1	$ 2,427,894.80	2.05%	4.36%	7.23%	0.30%	$49,772	$105,856	$175,537	$7,284	$338,449
502 Junction-Mt Storm-Meadowbrook (>=500kV) - CWIP[1]	b0328.2; b0347.1; b0347.2; b0347.3; b0347.4	$ 13,827,994.67	2.05%	4.36%	7.23%	0.30%	$283,474	$602,901	$999,764	$41,484	$1,927,622
Wylie Ridge [2]	b0218	$ 2,302,697.88	4.00%	10.00%	15.00%	1.00%	$92,108	$230,270	$345,405	$23,027	$690,809
Black Oak[1]	b0216	$ 9,198,118.76	2.05%	4.36%	7.23%	0.30%	$188,561	$401,038	$665,024	$27,594	$1,282,218
N Shenandoah Txfmr	b0323	$ 239,587.73	3.00%	6.00%	11.00%	0.00%	$7,188	$14,375	$26,355	$0	$47,918
Meadowbrook Txfmr	b0230	$ 898,323.05	2.00%	4.00%	6.00%	0.00%	$17,966	$35,933	$53,899	$0	$107,799
Totals		**$ 31,262,972.54**					**$639,069**	**$1,390,373**	**$2,265,984**	**$99,389**	**$4,394,814**
Notes on calculations >>>							= (a) * (b)	= (a) * (c)	= (a) * (d)	= (a) * (e)	= (f) + (g) + (h) + (i)

	(k)	(l)	(m)	(n)	(o)	(p)
Zonal Cost Allocation for New Jersey Zones	**Average Monthly Impact on Zone Customers in 08/09**	**2007 TX Peak Load** *per PJM website*	**Rate in $/MW-mo.**	**2008 Impact (4 months)**	**2009 Impact (5 months)**	**2008 - 2009 Impact [4] (9 months)**
PSE&G	$ 251,775.95	10,378.7	$ 24.26	$ 1,007,104	$ 1,258,880	$ 2,265,984
JCP&L	$ 154,485.86	6,256.3	$ 24.69	$ 617,943	$ 772,429	$ 1,390,373
ACE	$ 71,007.69	2,947.0	$ 24.09	$ 284,031	$ 355,038	$ 639,069
RE	$ 11,043.22	423.0	$ 26.11	$ 44,173	$ 55,216	$ 99,389
Total Impact on NJ Zones	**$ 488,312.71**			**$ 1,953,251**	**$ 2,441,564**	**$ 4,394,814**
Notes on calculations >>>			= (k) * (l)	= (k) * 4	= (k) * 5	= (n) * (o)

Notes:

1) 2008 allocation share percentages (columns e,f) were filed with FERC and are still pending - PJM uses revised percentages for billing purposes, but OATT still shows higher percentages.
The values used in this filing represents lower allocations (and costs).

2) PJM Settlement for "Below 500kV" filed in September 2007 FERC and still pending.

3) Allocation share percentages for Merchant Transmission Owners pending an ALJ decision after hearing which could affect all other allocation share percentages (columns b-d above - past, present and future).

4) Rate compression assumes BPU approves rate for implementation on September 1, 2008.

Attachment 6 a (ACE, JCP&L, PSE&G and RECO)
Translation of VEPCo Costs into BGS Rates

And

Attachment 6 b (ACE, JCP&L, PSE&G and RECO)
Translation of TrAILCo Costs into BGS Rates

Attachment 6 a

Atlantic City Electric Company
Proposed Dominion Project Transmission Enhancement Charge (Dominion Projects-TEC Surcharge) effective September 1, 2008
To reflect FERC-approved Dominion Project Transmission Enhancement Charge (Schedule 12 PJM OATT) effective January 1, 2008

Monthly Transmission Enhancement Costs Allocated to ACE Zone	$	11,215
2007 ACE Zone Transmission Peak Load (MW)		2,947
Transmission Enhancement Rate ($/MW-Month)	$	3.81

Rate Class	Col. 1 Transmission Obligation (MW)	Col. 2 Allocated Cost Recovery	Col. 3 BGS Eligible Sales September 2008 - December 2008 (kWh)	Col. 4 = Col. 2/Col. 3 Transmission Enhancement Charge ($/kWh)	Col. 5 = Col. 4 x 1/(1-.005) Transmission Enhancement Charge w/ BPU Assessment ($/kWh)	Col. 6 = Col. 5 x 1.07 Transmission Enhancement Charge w/ SUT ($/kWh)
RS	1,578	$ 24,029	1,384,055,310	$ 0.000017	$ 0.000017	$ 0.000018
MGS Secondary	387	$ 5,888	345,240,974	$ 0.000017	$ 0.000017	$ 0.000018
MGS Primary	6	$ 99	4,643,923	$ 0.000021	$ 0.000021	$ 0.000022
AGS Secondary	372	$ 5,657	421,947,270	$ 0.000013	$ 0.000013	$ 0.000014
AGS Primary	105	$ 1,605	100,908,807	$ 0.000016	$ 0.000016	$ 0.000017
TGS	236	$ 3,595	146,997,893	$ 0.000024	$ 0.000024	$ 0.000026
SPL/CSL	0	$ -	26,788,583	$ -	$ -	$ -
DDC	2	$ 26	3,225,862	$ 0.000008	$ 0.000008	$ 0.000009
	2,687	$ 40,897	2,433,808,622			

BGS-FP Supplier Payment Adjustment

Line No.				
1	BGS-FP Eligible Sales September - December @ cust (kWh)		2,320,135	MWH
2	BGS-FP Eligible Sales September - December @ trans node (kWh)		2,512,944	MWH
3	BGS-FP Eligible Transmission Obligation		2,362	MW
4	Transmission Enhancement Costs to FP Suppliers	$	35,955.12	=Line 3 x $3.81 x 4
5	Change in Supplier Payment Rate $/MWH (rounded to 2 decimals)	$	0.01	= Line 4/Line 2

Attachment 6 a

Jersey Central Power & Light Company
Proposed VEPCO Project Transmission Enhancement Charge (VEPCO-TEC Surcharge) effective September 1, 2008
To reflect FERC-approved VEPCO Project Transmission Enhancement Charge (Schedule 12 PJM OATT) effective April 29, 2008

2008 Average Monthly VEPCO-TEC Costs Allocated to JCP&L Zone	$	32,602.84	(1)
2007 JCP&L Zone Transmission Peak Load (MW)		6256.3	
VEPCO-Transmission Enhancement Rate ($/MW-month)	$	5.21	

				Effective September 1, 2008:	
BGS by Voltage Level	Transmission Obligation (MW)	Allocated Cost Recovery ($) (2)	BGS Eligible Sales (kWh) (3)	VEPCO-TEC Surcharge ($/kWh)	VEPCO-TEC Surcharge w/ SUT($/kWh)
Secondary (excluding lighting)	5553.0	115,751	5,833,639,119	$ 0.000020	$ 0.000021
Primary	353.9	7,377	690,716,848	$ 0.000011	$ 0.000012
Transmission @ 34.5 kV	330.3	6,885	677,828,974	$ 0.000010	$ 0.000011
Transmission @ 230 kV	19.1	398	144,800,315	$ 0.000003	$ 0.000003
Total	6256.3	130,411	7,346,985,256		

(1) Attachment 5a Cost Allocation of VEPCO Project Schedule 12 Charges to JCP&L Zone for 2008
(2) Based on 4 months VEPCO Project costs from September 2008 through December 2008
(3) September 2008 through December 2008

BGS-FP Supplier Payment Adjustment

Line No.				
1	BGS-FP Eligible Sales September through December @ Customer		5,397,732	MWH
2	BGS-FP Eligible Sales September through December @ Transmission Node		5,953,105	MWH
3	BGS-FP Eligible Transmission Obligation		5,814	MW
4	VEPCO-Transmission Enhancement Costs to FP Suppliers	$	121,192	= Line 3 x $5.21 x 4
5	Change to Supplier Payment Rates $/MWH (rounded to 2 decimals)	$	0.02	= Line 4 / Line 2

Attachment 6a - PSE&G
Transmission Charge Adjustement - BGS-FP
PJM Schedule 12 - Transmission Enhancement Charges for January 2008 - December 2008
Calculation of costs and monthly PJM charges for Virginia Power and Electric Company Projects

TEC Charges for Sept 2008 - December 2008	$	247,931.23	
PSE&G Zonal Transmission Load for Effective Yr. (MW)		10,378.70	
Term (Months)		4	
OATT rate	$	5.97	/MW/month
converted to $/MW/yr =	$	71.64	/MW/yr

all values show w/o NJ SUT

	RS	RHS	RLM	WH	WHS	HS	PSAL	BPL
Trans Obl - MW	4404.0	44.0	95.0	0.0	0.0	6.0	0.0	0.0
Total Annual Energy - MWh	13,246,996	198,610	300,135	2,743	71	28,679	164,262	327,325
Change in energy charge								
in $/MWh	$ 0.0238	$ 0.0159	$ 0.0227	$ -	$ -	$ 0.0150	$ -	$ -
in cents/kWh - rounded to 4 places	**0.0024**	**0.0016**	**0.0023**	**0**	**0**	**0.0015**	**0**	**0**

	GLP	LPL-S	
Change in Transmission Obligation Charge			
in $/kW/month - rounded to 4 places	**$ 0.0060**	**$ 0.0060**	<< same increase to BGS-CIEP Transmission Obligation Charges

Line #					
1	Total BGS-FP eligbile Trans Obl	9052	MW		= sum of BGS-FP eligible Trans Obl
2	Total BGS-FP eligbile energy @ cust	32,526,058	MWh		= sum of BGS-FP eligible kWh @ cust
3	Total BGS-FP eligbile energy @ trans nodes	34,810,786	MWh	unrounded	= (2) * loss expansion factor to trans node
4	Change in OATT rate * total Trans Obl	$ 648,485		unrounded	= Change in OATT rate * Total BGS-FP eligible Trans C
5	Change in Average Supplier Payment Rate	$ 0.0186	/MWh	unrounded	= (4) / (3)
6	Change in Average Supplier Payment Rate	$ 0.02	/MWh	rounded to 2 decimal places	= (5) rounded to 2 decimal places
7	Proposed Total Supplier Payment	$ 696,216		unrounded	= (6) * (3)
8	Difference due to rounding	$ 47,730		unrounded	= (7) - (4)

Attachment 6a

Rockland Electric Company

Proposed Transmission Enhancement Charge Surcharge for the Period September 1, 2008 through December 31, 2008

To reflect FERC-approved VEPCo Project Schedule 12 Charges (Schedule 12 PJM OATT) for the period January 1, 2008 to December 31, 2008

2008 Average Monthly VEPCo-TEC Costs Allocated to RECO	$	488	(1)
2007 RECO Zone Transmission Peak Load (MW)		423.0	
Transmission Enhancement Rate ($/MW-Month)	$	1.15	

	Col. 1	Col. 2	Col.3=Col.2 x $488 x 4	Col. 4	Col. 5 = Col. 3/Col. 4	Col. 6 = Col. 5 x 1.07	Col. 7	Col. 8 = Col. 6 + Col. 7
Rate Class	Transmission Obligation (MW)	Transmission Obligation (Pct)	Allocated Cost Recovery	BGS Eligible Sales September 2008 - December 2008 (kWh)	Transmission Enhancement Charge ($/kWh)	Transmission Enhancement Charge w/ SUT ($/kWh)	Reliability Must Run Charges w/SUT ($/kWh)	Transmission Surcharges
SC1	276.3	58.79%	$ 1,149	253,336,000	$ -	$ -	$ 0.00010	$ 0.00010
SC2 Secondary	133.9	28.49%	$ 557	196,574,000	$ -	$ -	$ 0.00010	$ 0.00010
SC2 Primary	19.4	4.13%	$ 81	42,506,000	$ -	$ -	$ 0.00010	$ 0.00010
SC3	0.1	0.02%	$ -	96,000	$ -	$ -	$ 0.00010	$ 0.00010
SC4	0.0	0.00%	$ -	2,559,000	$ -	$ -	$ 0.00011	$ 0.00011
SC5	3.8	0.81%	$ 16	6,472,000	$ -	$ -	$ 0.00010	$ 0.00010
SC6	0.0	0.00%	$ -	2,100,000	$ -	$ -	$ 0.00011	$ 0.00011
SC7	36.5	7.77%	$ 152	66,501,000	$ -	$ -	$ 0.00010	$ 0.00010
Total	470.0 (2)	100.00%	$ 1,955	570,144,000				

(1) Attachment 5a Cost Allocation of VEPCo Schedule 12 Charges to RECO Zone for June 2008 through December 2008

(2) Includes RECO's Central and Western Divisions

BGS-FP Supplier Payment Adjustment

Line No.				
1	BGS-FP Eligible Sales Sep 2008 - Dec 2008 @ cust (RECO Eastern Division)		449,015	MWH
2	BGS-FP Eligible Sales Sep 2008 - Dec 2008 @ trans node (RECO Eastern Division)		481,249	MWH
3	BGS-FP Eligible Transmission Obligation		386	MW
4	Transmission Enhancement Costs to FP Suppliers	$	1,775.60	=Line 3 x $1.15 * 4
5	Change in Supplier Payment Rate $/MWH (rounded to 2 decimals)	$	-	= Line 4/Line 2

Attachment 6 b

Atlantic City Electric Company
Proposed Allegheny TrAILCo Project Transmission Enhancement Charge (Allegheny TrAILCo-TEC Surcharge) effective September 1, 2008
To reflect FERC-approved TrAILCo Project Transmission Enhancement Charge (Schedule 12 PJM OATT) effective June 1, 2008

Monthly Transmission Enhancement Costs Allocated to ACE Zone	$	71,008
2007 ACE Zone Transmission Peak Load (MW)		2,947
Transmission Enhancement Rate ($/MW-Month)	$	24.09

Rate Class	Col. 1 Transmission Obligation (MW)	Col. 2 Allocated Cost Recovery	Col. 3 BGS Eligible Sales September 2008 - May 2009 (kWh)	Col. 4 = Col. 2/Col. 3 Transmission Enhancement Charge ($/kWh)	Col. 5 = Col. 4 x 1/(1-.005) Transmission Enhancement Charge w/ BPU Assessment ($/kWh)	Col. 6 = Col. 5 x 1.07 Transmission Enhancement Charge w/ SUT ($/kWh)
RS	1,578	$ 342,301	3,075,993,400	$ 0.000111	$ 0.000112	$ 0.000120
MGS Secondary	387	$ 83,879	744,577,627	$ 0.000113	$ 0.000114	$ 0.000122
MGS Primary	6	$ 1,405	7,298,069	$ 0.000192	$ 0.000193	$ 0.000207
AGS Secondary	372	$ 80,583	929,466,669	$ 0.000087	$ 0.000087	$ 0.000093
AGS Primary	105	$ 22,858	227,905,376	$ 0.000100	$ 0.000101	$ 0.000108
TGS	236	$ 51,207	316,866,950	$ 0.000162	$ 0.000163	$ 0.000174
SPL/CSL	0	$ -	58,809,479	$ -	$ -	$ -
DDC	2	$ 368	7,122,282	$ 0.000052	$ 0.000052	$ 0.000056
	2,687	$ 582,601	5,368,039,852			

BGS-FP Supplier Payment Adjustment

Line No.				
1	BGS-FP Eligible Sales September - May @ cust (kWh)		5,117,320	MWH
2	BGS-FP Eligible Sales September - May @ trans node (kWh)		5,542,915	MWH
3	BGS-FP Eligible Transmission Obligation		2,362	MW
4	Transmission Enhancement Costs to FP Suppliers	$	512,093.95	=Line 3 x $24.09 x 9
5	Change in Supplier Payment Rate $/MWH (rounded to 2 decimals)	$	0.09	= Line 4/Line 2

Attachment 6 b

Jersey Central Power and Light Comapny

Proposed TRAILCO Project Transmission Enhancement Charge (TRALCO-TEC Surcharge) effective September 1, 2008
To reflect FERC-approved TRAILCO Project Transmission Enhancement Charge (Schedule 12 PJM OATT) effective June 1, 2008

2008 Average Monthly TRAILCO-TEC Costs Allocated to JCP&L Zone	$	154,485.86	(1)
2007 JCP&L Zone Transmission Peak Load (MW)		6256.3	
TRAILCO-Transmission Enhancement Rate ($/MW-month)	$	24.69	

				Effective September 1, 2008:	
BGS by Voltage Level	Transmission Obligation (MW)	Allocated Cost Recovery ($) (2)	BGS Eligible Sales (kWh) (3)	TRAILCO-TEC Surcharge ($/kWh)	TRAILCO-TEC Surcharge w/ SUT($/kWh)
Secondary (excluding lighting)	5553.0	1,234,074	13,126,025,924	$ 0.000094	$ 0.000101
Primary	353.9	78,649	1,508,602,839	$ 0.000052	$ 0.000056
Transmission @ 34.5 kV	330.3	73,404	1,488,369,085	$ 0.000049	$ 0.000052
Transmission @ 230 kV	19.1	4,245	315,531,658	$ 0.000013	$ 0.000014
Total	6256.3	1,390,373	16,438,529,505		

(1) Attachment 5b Cost Allocation of TRAILCO Project Schedule 12 Charges to JCP&L Zone for 2008/2009
(2) Based on 9 months TRAILCO Project costs from September 2008 through May 2009
(3) September 2008 through May 2009

BGS-FP Supplier Payment Adjustment

Line No.				
1	BGS-FP Eligible Sales September through May @ Customer		12,083,857	MWH
2	BGS-FP Eligible Sales September through May @ Transmission Node		13,327,165	MWH
3	BGS-FP Eligible Transmission Obligation		5,814	MW
4	TRAILCO-Transmission Enhancement Costs to FP Suppliers	$	1,292,078	= Line 3 x $24.69 x 9
5	Change to Supplier Payment Rates $/MWH (rounded to 2 decimals)	$	0.10	= Line 4 / Line 2

Attachment 6b - PSE&G
Transmission Charge Adjustement - BGS-FP
PJM Schedule 12 - Transmission Enhancement Charges for June 2008 - May 2009
Calculation of costs and monthly PJM charges for Allegheny TrAILCo Projects 2008 Annual Update

TEC Charges for Sept 2008 - May 2009	$ 2,265,983.51		
PSE&G Zonal Transmission Load for Effective Yr. (MW)	10,378.70		
Term (Months)	9		
OATT rate	$ 24.26	/MW/month	all values show w/o NJ SUT
converted to $/MW/yr =	$ 291.12	/MW/yr	

	RS	RHS	RLM	WH	WHS	HS	PSAL	BPL
Trans Obl - MW	4404.0	44.0	95.0	0.0	0.0	6.0	0.0	0.0
Total Annual Energy - MWh	13,246,996	198,610	300,135	2,743	71	28,679	164,262	327,325
Change in energy charge								
in $/MWh	$ 0.0968	$ 0.0645	$ 0.0921	$ -	$ -	$ 0.0609	$ -	$ -
in cents/kWh - rounded to 4 places	**0.0097**	**0.0064**	**0.0092**	**0**	**0**	**0.0061**	**0**	**0**

	GLP	LPL-S	
Change in Transmission Obligation Charge			
in $/kW/month - rounded to 4 places	**$ 0.0243**	**$ 0.0243**	<< same increase to BGS-CIEP Transmission Obligation Charges

Line #					
1	Total BGS-FP eligbile Trans Obl	9052	MW		= sum of BGS-FP eligible Trans Obl
2	Total BGS-FP eligbile energy @ cust	32,526,058	MWh		= sum of BGS-FP eligible kWh @ cust
3	Total BGS-FP eligbile energy @ trans nodes	34,810,786	MWh	unrounded	= (2) * loss expansion factor to trans node
4	Change in OATT rate * total Trans Obl	$ 2,635,218		unrounded	= Change in OATT rate * Total BGS-FP eligible Trans
5	Change in Average Supplier Payment Rate	$ 0.0757	/MWh	unrounded	= (4) / (3)
6	Change in Average Supplier Payment Rate	$ 0.08	/MWh	rounded to 2 decimal places	= (5) rounded to 2 decimal places
7	Proposed Total Supplier Payment	$ 2,784,863		unrounded	= (6) * (3)
8	Difference due to rounding	$ 149,645		unrounded	= (7) - (4)

Attachment 6b

Rockland Electric Company

Proposed Transmission Enhancement Charge Surcharge for the Period September 1, 2008 through May 31, 2009

To reflect FERC-approved TrailCo Project Schedule 12 Charges (Schedule 12 PJM OATT) for the period June 1, 2008 to May 31, 2009

2008 Average Monthly TrailCo-TEC Costs Allocated to RECO	$	11,043	(1)
2007 RECO Zone Transmission Peak Load (MW)		423.0	
Transmission Enhancement Rate ($/MW-Month)	$	26.11	

Rate Class	Col. 1 Transmission Obligation (MW)	Col. 2 Transmission Obligation (Pct)	Col.3=Col.2 x $11,043 x 9 Allocated Cost Recovery	Col. 4 BGS Eligible Sales September 2008 - May 2009 (kWh)	Col. 5 = Col. 3/Col. 4 Transmission Enhancement Charge ($/kWh)	Col. 6 = Col. 5 x 1.07 Transmission Enhancement Charge w/ SUT ($/kWh)	Col. 7 Reliability Must Run Charges w/SUT ($/kWh)	Col. 8 = Col. 6 + Col. 7 Transmission Surcharges
SC1	276.3	58.79%	$ 58,428	527,421,000	$ 0.00011	$ 0.00012	$ 0.00010	$ 0.00022
SC2 Secondary	133.9	28.49%	$ 28,315	426,370,000	$ 0.00007	$ 0.00007	$ 0.00010	$ 0.00017
SC2 Primary	19.4	4.13%	$ 4,102	91,486,000	$ 0.00004	$ 0.00004	$ 0.00010	$ 0.00014
SC3	0.1	0.02%	$ 21	237,000	$ 0.00009	$ 0.00010	$ 0.00010	$ 0.00020
SC4	0.0	0.00%	$ -	5,443,000	$ -	$ -	$ 0.00011	$ 0.00011
SC5	3.8	0.81%	$ 804	15,371,000	$ 0.00005	$ 0.00005	$ 0.00010	$ 0.00015
SC6	0.0	0.00%	$ -	4,317,000	$ -	$ -	$ 0.00011	$ 0.00011
SC7	36.5	7.77%	$ 7,719	153,086,000	$ 0.00005	$ 0.00005	$ 0.00010	$ 0.00015
Total	470.0 (2)	100.00%	$ 99,389	1,223,731,000				

(1) Attachment 5b Cost Allocation of TrailCo Schedule 12 Charges to RECO Zone for June 2008 through May 2009

(2) Includes RECO's Central and Western Divisions

BGS-FP Supplier Payment Adjustment

Line No.				
1	BGS-FP Eligible Sales Sep 2008 - May 2009 @ cust (RECO Eastern Division)		950,199	MWH
2	BGS-FP Eligible Sales Sep 2008 - May 2009 @ trans node (RECO Eastern Division)		1,018,413	MWH
3	BGS-FP Eligible Transmission Obligation		386	MW
4	Transmission Enhancement Costs to FP Suppliers	$	90,706.14	=Line 3 x $26.11 * 9
5	Change in Supplier Payment Rate $/MWH (rounded to 2 decimals)	$	0.09	= Line 4/Line 2

Attachment 7a
FERC Order on VEPCo Formula Rates

Attachment 7b
TrAILCo Formula Rate Update Compliance Filing

123 FERC ¶ 61,098
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Joseph T. Kelliher, Chairman;
Suedeen G. Kelly, Marc Spitzer,
Philip D. Moeller, and Jon Wellinghoff.

Virginia Electric and Power Company — Docket Nos. ER08-92-000, ER08-92-001, ER08-92-002, ER08-92-003

ORDER ON FORMULA RATE PROPOSAL

(Issued April 29, 2008)

1. On October 25, 2007, Virginia Electric and Power Company (VEPCO) filed revised tariff sheets to Attachment H-16 and Schedules 7, 8, and 12 of PJM Interconnection, L.L.C.'s (PJM) Open Access Transmission Tariff (OATT) to substitute a formula rate for its stated rates for Network Integration Transmission Service (NITS) and Point-to-Point transmission service (October 25 Filing). VEPCO also requested a 50 basis point adder to the return on equity (ROE) reflected in its formula rate as an incentive for continued membership in a regional transmission organization (RTO), pursuant to Order Nos. 679 and 679-A.[1] In this order, the Commission accepts the formula rate proposed by VEPCO, with certain modifications, rejects its proposed ROE and requires a compliance filing as discussed herein, effective January 1, 2008.

I. Background

2. VEPCO states that it is in the early stages of a major expansion of its transmission system due to continued peak load growth. VEPCO expects to participate in the construction of transmission projects included in PJM's Regional Transmission Expansion Plan (RTEP).

3. On October 25, 2007, in Docket No. ER08-92-000, VEPCO filed revised tariff sheets to PJM's OATT which would substitute a forward-looking formula rate for its currently-effective stated rates for transmission service within the VEPCO zone of PJM.

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[1] *Promoting Transmission Investment through Pricing Reform*, Order No. 679, FERC Stats. & Regs. ¶ 31,222 , *order on reh'g*, Order No. 679-A, FERC Stats. & Regs. ¶ 31,236 (2006), *order on reh'g*, 119 FERC ¶ 61,062 (2007).

VEPCO states that a forward-looking formula rate will (1) provide for the timely and administratively efficient recovery of the costs associated with the expansion, (2) eliminate the need for multiple filings under section 205 of the Federal Power Act,[2] and (3) allow for the systematic adjustment of its rates to reflect changes in transmission costs and loads over time. VEPCO states that its proposed formula rate is consistent with other Commission-approved formula rates. Specifically, VEPCO states that the foundation for its proposal is the formula rate from an uncontested settlement approved by the Commission in *PHI/BGE*[3] and incorporates the forward-looking features adopted by the Commission in *ITC*.[4] According to VEPCO, formulas that are updated after FERC Form No. 1 data becomes available, inherently build 5 to 17 months of lag in between the end of the cost year and the beginning of the rate year, thus detrimentally impacting the utility's ability to recover its prudently-incurred costs in a timely manner.

4. On December 19, 2007, the Commission staff issued a deficiency letter requesting additional information to be filed by January 18, 2008 (Deficiency Letter). The additional information requested dealt with, *inter alia*, cost and revenue data required by section 35.13 of the Commission's regulations and detailed explanations of the formula rate and the True-Up Adjustment.

5. On January 10, 2008 (January 10 Filing), as amended on January 11, 2008 (January 11 Filing), VEPCO filed in Docket No. ER08-92-001, its response to the majority of staff's questions and noted that it would be filing several more responses by the January 18, 2008 due date. In addition, VEPCO requested that the Commission staff "modify the [Deficiency L]etter to not require [VEPCO]" to answer the questions on actual cost-of-service data for the 2006 calendar year (Period 1) and for projected cost-of-service data for the 2008 calendar year (Period 2). In the alternative, VEPCO requested a one-month extension of time, to February 19, 2008, to answer the Deficiency Letter. On January 18, 2008, VEPCO filed in Docket No. ER08-92-002 its responses to several outstanding questions from staff in the Deficiency Letter. On February 12, 2008, VEPCO requested an additional 10-day extension of its already extended due date of February 19, 2008 to respond to certain questions regarding cost-of-service data. On February 29, 2008, in Docket No. ER08-92-003, VEPCO filed its responses to staff's remaining questions.

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[2] 16 U.S.C. § 824d (2000).

[3] *Baltimore Gas and Electric Co.*, 115 FERC ¶ 61,066 (*PHI/BGE*) (2006).

[4] *International Transmission Co.*, 116 FERC ¶ 61,036 at P19 (*ITC*) (2006).

II. <u>Proposal</u>

6. VEPCO proposes to utilize a forward-looking formula rate in calculating its annual transmission rates, instead of the current stated cost-of-service rate it uses. VEPCO proposes a forward-looking formula which will be used to calculate its Annual Transmission Revenue Requirement (ATRR). The annual rate for transmission service will then be calculated by dividing the ATRR by the annual single-day coincidental peak for the 12-month period ending October 31 of the previous year. As described in greater detail herein, the proposed forward-looking formula is adjusted annually through an Annual Update which is based on projected costs, and subsequently reconciled to actual costs in the following year using the True-Up Adjustment process set forth in VEPCO's tariff sheets.

7. To effectuate its formula rate, VEPCO proposes to make the following changes to PJM's OATT:

- Revise Attachment H-16, *Annual Transmission Rates for Network Integration Transmission Service*, to: (1) eliminate VEPCO's "stated" ATRR of $155,000,000 and the rate for NITS of $10,971.35 per MW per year and replace these amounts with amounts to be determined according to the formula contained in the new Attachment H-16A, *Formula Rate – Appendix A*, and the protocols contained in the new Attachment H-16B, *Formula Rate Implementation Protocols* and (2) specify the calculation of revenue credits.

- Add new Attachment H-16A, *Formula Rate – Appendix A*, which is a spreadsheet containing formulas to calculate VEPCO's ATRR and the rate for transmission service in the VEPCO zone of PJM.

- Add new Attachment H-16B, *Formula Rate Implementation Protocols*, which will set out the implementation protocols for the formula rate. Attachment H-16B specifies: (1) the projected and actual costs which will be used in determining the ATRR and the rate for transmission service in the VEPCO zone of PJM, (2) how the True-Up Adjustment will be implemented, and (3) the procedures for reviewing and challenging the inputs to the spreadsheet.

- Revise Schedules 7 and 8 to replace VEPCO's existing stated rates for transmission service to delivery points within the VEPCO Zone with rates that are derived from the VEPCO formula.

- Make non-substantive changes to effectuate the formula rate by: (1) revising Schedule 12 to reference the derivation of VEPCO's annual revenue requirements for its RTEP projects for which it seeks recovery, (2) moving from Attachment H-16A to Attachment H-16C the Virginia Retail

Administrative Fee Credit for Virginia Load Serving Entities in the VEPCO Zone, and (3) moving from Attachment H-16B to Attachment H-16D the proposed rates for wholesale distribution service.

8. VEPCO requests an effective date of January 1, 2008 for its proposed revisions to the PJM OATT.

III. Notice, Interventions, and Protests

9. Notice of VEPCO's October 25 Filing in Docket No. ER08-92-000 was published in the *Federal Register*, 72 Fed. Reg. 62,842 (2007), with interventions and protests due on or before November 15, 2007. Timely motions to intervene were filed by American Electric Power Service Corporation, Exelon Corporation (Exelon), PJM, PJM Industrial Customer Coalition, and PPL Electric Utilities Corporation. Timely motions to intervene or notices of intervention and comments were filed by PHI Companies,[5] the Public Service Commission of Maryland (Maryland Commission), the Staff of the Virginia State Corporation Commission (VSCC Staff), and Public Service Electric and Gas Company (PSE&G). A timely motion to intervene and protest was filed by the Office of the Attorney General of Virginia, Division of Consumer Counsel (Virginia Consumer Counsel).

10. Baltimore Gas and Electric Company (BG&E) filed a motion to intervene, comments, and a request for maximum suspension period. Indicated Customers[6] filed a motion to intervene, protest, request for a hearing, and opposition to waivers. North Carolina Agencies[7] and the Virginia Municipal Electric Association No. 1 (VMEA)[8] filed

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[5] The PHI Companies are Pepco Holdings, Inc., Potomac Electric Power Company (Pepco), Atlantic City Electric Company and Delmarva Power & Light Company.

[6] Indicated Customers are Central Virginia Electric Cooperative, Craig-Botetourt Electric Cooperative, North Carolina Electric Membership Corporation and Old Dominion Electric Cooperative.

[7] North Carolina Agencies are the North Carolina Utilities Commission, the Public Staff – North Carolina Utilities Commission, and the Attorney General of the State of North Carolina.

[8] The members of VMEA – Blackstone, Culpeper, Elkton, Franklin, Manassas and Wakefield, Virginia, and the Harrisonburg Electric Commission – state that the issues of significance to VMEA have been raised in the protest filed on November 15 by Indicated Customers.

a motion to intervene or notice of intervention, protests, and requests for a hearing. On November 30, 2007, VEPCO filed an answer to the comments and protests. On December 17, 2007, Indicated Customers filed an answer to VEPCO's answer.

11. Notice of VEPCO's January 10 Filing, as amended on January 11, in Docket No. ER08-92-001 was published in the *Federal Register*, 73 Fed. Reg. 4,202 (2008), with interventions and protests due on or before January 30, 2008. On January 18, 2008, Indicated Customers filed an answer opposing or commenting on certain procedural requests of VEPCO's January 10 Filing. Notice of VEPCO's January 18 Filing in Docket No. ER08-92-002 was published in the *Federal Register*, 73 Fed. Reg. 6,174 (2008), with interventions and protests due on or before January 31, 2008. On January 31, 2008, Indicated Customers filed a protest to VEPCO's filings of January 10 and 11, 2008 and January 18, 2008, which provided responses to the Deficiency Letter.

12. Notice of VEPCO's February 29 Filing was published in the *Federal Register*, 73 Fed. Reg. 13,877 (2008), with interventions and protests due on or before March 21, 2008. On March 21, 2008, Indicated Customers filed a protest to VEPCO's February 29, 2008 filing (Indicated Customers March 21 Supplemental Protest). Also on March 21, 2008, Virginia Consumer Counsel filed comments. On April 2, 2008, VEPCO filed an answer to the March 21 protests by Indicated Customers and Virginia Consumer Counsel (VEPCO April 2 Answer). On April 15, 2008, Indicated Customers filed an answer to VEPCO's April 2 Answer.

IV. Discussion

A. Procedural Matters

13. Pursuant to Rule 214 of the Commission's Rules of Practice and Procedure,[9] the notices of intervention and timely, unopposed motions to intervene serve to make the entities that filed them parties to this proceeding.

14. Rule 213(a)(2) of the Commission's Rules of Practice and Procedure[10] prohibits an answer to an answer or protest unless otherwise permitted by the decisional authority. In this case, we find that VEPCO's November 30 and April 2 answers and Indicated Customers' December 17 and April 15 answers have assisted the Commission in its decision-making process.[11] Therefore, we will accept them.

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[9] 18 C.F.R. § 385.214 (2007).

[10] 18 C.F.R. § 385.213(a)(2) (2007).

[11] *See, e.g.*, *Midwest Independent System Operator Corp.*, 121 FERC ¶ 61,132, at P 12 (2007); *Westar Energy, Inc.*, 121 FERC ¶ 61,108, at P 18 (2007).

B. Formula Rate Proposal

15. We approve VEPCO's proposal to implement a transmission cost of service formula rate. The Commission has found that the use of formula rates encourages the construction and timely placement into service of needed transmission infrastructure.[12]

16. The Commission has approved the use of formula rates by a number of transmission-owning utilities in the PJM region, both those utilizing prior-year FERC Form No. 1 data to calculate rates for the upcoming year,[13] as well as those utilizing projected costs, as VEPCO proposes to do.[14] In each case, the fundamental process for the formula rates remains the same: rates are estimated for the following year, either through prior-year FERC Form No. 1 data or through projections, and data regarding such rates is provided to customers with sufficient time for them to review the rates before they are implemented and challenge them before the Commission if necessary. Once the actual costs are known from that year's FERC Form No. 1, those costs are trued-up to the rates that have been charged over the past year and any over-collections are returned to customers with interest at the FERC interest rate. These mechanisms allow the utility to recover its costs in a more timely manner while also protecting customers from inflated rates through the true-up process. Since over-collections are returned to customers with interest at the FERC interest rate, customers are made whole from any excessive projections or over-collections.[15] As discussed herein, VEPCO's proposal is consistent with this structure.

1. Formula Rate Proposal

a. Use Of Projected Costs

i. VEPCO's Proposal

17. VEPCO's proposed formula rate is contained in Attachment H-16A, Appendix A to PJM's OATT, which consists of a spreadsheet and supporting documents. VEPCO's

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[12] *See Northeast Utilities Service Co.*, 105 FERC ¶ 61,089, at P 23 (2003).

[13] *PHI/BGE*, 115 FERC ¶ 61,066; *Duquesne Light Co.*, 118 FERC ¶ 61,087 (2007).

[14] *Potomac-Appalachian Transmission Highline, L.L.C.*, 122 ¶ FERC 61,188 (2008) (*PATH*).

[15] *International Transmission Co.*, 116 FERC ¶ 61,036, at P 20 (2006) (*ITC*).

ATRR will be calculated by entering data into the spreadsheet. The annual rate for transmission service will then be calculated by dividing the ATRR by the annual single-day coincidental peak for the 12-month period ending October 31 of the previous year.[16]

18. VEPCO states that its utilization of projected costs parallels the traditional reliance on Period II cost of service data for establishing rates.[17] In addition, VEPCO states that the key modification to its proposed formula, as compared to the PHI/BGE formula, is its accommodation of projected calendar year cost-of-service data to determine an ATRR and rates. VEPCO also states that the majority of the projected cost-of-service data is derived from VEPCO's budgets. VEPCO states that, as with the ITC formula, the ATRR and the rates are ultimately trued-up with interest using actual calendar year cost-of-service data. VEPCO also states that the actual data is taken from FERC Form No. 1 or from accounting data that are consistent with the FERC Form No. 1 data.[18]

19. VEPCO also proposes to modify the PHI/BGE formula by using average balances for inclusion in rate base rather than end-of-year balances. An average of the 13 months' balances for the calendar year will be used for each balance for plant in service and depreciation. Further, for every other type of balance in rate base, VEPCO proposes to use the average of the balance for the beginning and end of the calendar year.

20. VEPCO proposes that its rate be effective January 1, 2008 for a calendar year – the same year for which it uses projected cost-of service data. VEPCO notes that this is another feature of its proposal that differs from the PHI/BGE formula, which uses the twelve months beginning June 1. For calendar year 2008, VEPCO's ATRR is contained in the instant filing and supported by testimony.[19] For each year thereafter, VEPCO will post on PJM's website by September 15 its proposed Annual Update, which will reflect the projected costs to be used to determine the rates for the subsequent calendar year. VEPCO will file with the Commission, in an informational filing, its proposed Annual Update by December 15.

21. VEPCO requests an ROE of 11.73 percent, plus a 50 basis point adder to its proposed ROE for continued membership in PJM, for a total ROE of 12.23 percent.

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[16] *See* October 25 Filing, Exhibit No. DVP-2, Direct Testimony Mr. James Daniel Jackson, Jr. (Jackson Testimony).

[17] *Id.* at 7.

[18] *Id*. at 8.

[19] *See* October 25 Filing, Exhibit Nos. DVP-8, Attachment H-16A, *Formula Rate – Appendix A*; DVP-9, Direct Testimony of Mr. Alexander N. Bailey (Bailey Testimony); and DVP-10, Direct Testimony of Mr. Leo R. Meyer.

VEPCO states that the range of implied cost of equity is from 7.85 percent to 15.61 percent, with the midpoint of the range produced by the adjusted proxy group being 11.73 percent. VEPCO states that the requested 50 basis point adder is appropriate because the Commission has consistently authorized a 50 basis point ROE adder in order to encourage RTO membership, specifically for RTO participants that continue such participation.[20]

22. VEPCO states that it is not seeking an ROE transmission rate incentive in this proceeding. However, VEPCO notes that it has included placeholders for ROE incentives in its formula in order to accommodate projects which may receive incentives at varying ROE levels in the future.[21] VEPCO states that the placeholders will only be changed pursuant to a Commission ruling in a section 205 filing.

23. VEPCO states that its proposed rates reflect a $66,500,000 increase in revenues when compared to its currently-effective ATRR of $155,000,000.[22] This is an increase of 42.9 percent. VEPCO states that its requested rate increase does not include the recovery of any RTO start-up costs or administrative fees.

ii. <u>Comments and Protests</u>

24. The Virginia Consumer Counsel and Indicated Customers raise concerns with VEPCO's proposal to use projected costs. They are concerned that parties will not be able to meaningfully analyze the projected costs which will be derived from VEPCO's internal budgets. They are also concerned with the accuracy and reasonableness of the projections.

25. Indicated Customers take exception to VEPCO's reliance on the ITC formula. For example, they note that unlike ITC, which is a single-purpose new transmission project, VEPCO is a vertically-integrated plant. They add that VEPCO's estimated cost of new transmission investment is $2 billion, which is only a small portion of VEPCO's electric plant-in-service of $23 billion (for the year ending December 2008). In addition, Indicated Customers take exception to VEPCO's contention that its forward-looking proposal is not a departure from "traditional" ratemaking.[23] Rather, Indicated Customers note that under "traditional" ratemaking when projected costs are used: (1) the utility

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[20] *Citing Duquesne Light Co.*, 118 FERC 61,087, at P 50 (2007); *Commonwealth Edison Co.*, 119 FERC 61,238, at P 72, 77 (2007) (*ComEd*).

[21] Jackson Testimony at 13.

[22] October 25 Filing at 9.

[23] *Citing ITC*, 116 FERC ¶ 61,036 at P 19.

makes a FPA section 205 filing, (2) the filing is noticed and customers have an opportunity to challenge the filing, and (3) the Commission reviews the projections to determine that the resulting rates are just and reasonable. However, Indicated Customers contend that under VEPCO's proposal: (1) VEPCO proposes that only the revised Annual Update be submitted as an "informational" filing, but not the initial Annual Update or the True-Up Adjustment, and (2) such informational filings do not give customers an opportunity to challenge the projections or resulting rates before they take effect.

26. Indicated Customers recommend that the Commission require VEPCO to annually file its proposed changes in charges produced under the formula rates pursuant to FPA section 205. Indicated Customers state that under this approach, the Commission would retain its authority to provide maximum protection against abuse of formula rates while not depriving VEPCO of the legitimate benefits of a formulary approach to ratemaking. Indicated Customers further state that formula would still be the "filed rate," and that investigations would not "open up" the formula. Indicated Customers argue that with an annual filing, there should be little or no controversy triggering the Commission's exercise of its section 205 remedial powers.

27. In response to VEPCO's February 29 Filing, Indicated Customers contend that VEPCO's filing still lacks cost support, workpapers, budgets, underlying assumptions or other data to support its projected Period II revenue requirements, which result in a 42.9 percent increase in its ATRR. Indicated Customers request that the Commission reject VEPCO's formula rate filing as deficient. In the alternative, Indicated Customers request that an evidentiary hearing be established to examine the justness and reasonableness of VEPCO's formula rate proposal.

iii. Commission Determination

28. The Commission will approve the forward-looking aspect of VEPCO's proposed formula rate. As VEPCO notes, the use of estimated costs in determining rates is not a change in Commission policy. In fact, the Commission has recently approved formula rate proposals very similar to the instant proposal.[24]

29. Indicated Customers and the VSCC Staff express concern that they will not be able to "meaningfully analyze" the projections provided by VEPCO and express concern over the accuracy of such projections. VEPCO has proposed an annual update process that will provide its customers with sufficient opportunity to evaluate its projected rates.

[24] *Xcel Energy Service, Inc.*, 121 FERC ¶ 61,284 (2007) (*Xcel*); *Michigan Electric Transmission Co.*, 117 FERC ¶ 61,314 (2006), *order on reh'g*, 118 FERC ¶ 61,139 (2007) (*Michigan Electric*).

30. For the forward-looking ATRR, which reflects projected costs, VEPCO will post on the PJM website, by September 15 of each year, its Annual Update which contains: (1) its projected costs, including the ATRR and NITS rate, (2) its estimated peak load, and (3) any Material Accounting Changes. VEPCO also will provide a spreadsheet containing its projected rates. By September 30 of each year, VEPCO will hold a public meeting to explain the projected costs and respond to questions from its customers.[25] During this process, VEPCO must make available sufficient information for parties to evaluate the accuracy of its forward-looking ATRR.[26] This process provides sufficient opportunity for customers to review VEPCO's projected costs, discuss those costs with VEPCO, and challenge them before the Commission if the explanations offered by VEPCO are not sufficient.

31. We deny Indicated Customers' request that VEPCO be required to file a limited section 205 filing each year, containing its Annual Update and True-Up Adjustment. When the Commission approves a company's request for a formula rate, it approves the formula itself, which becomes the filed rate. There is no need to file each Annual Update or True-Up Adjustment under section 205 because the data contained in these processes is not the rate; it is merely an input into the formula, which is the rate. Any excess costs charged as a result of inaccurate projections will be returned to customers, with interest at the FERC interest rate, during the True-Up Adjustment process.

32. We also deny Indicated Customers' request to reject the filing as deficient or to set the proceeding for hearing. Although VEPCO did not submit as much information as is required for Period II costs, the true-up mechanism contained in VEPCO's proposal obviates the need for the filing of all of the data specified in our regulations for Period II costs.[27]

b. True-Up Adjustment

i. VEPCO's Proposal

33. VEPCO's proposed protocols, setting forth the procedures by which VEPCO will implement its formula rate, are contained in Attachment H-16B of Appendix A to PJM's OATT.

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[25] Attachment H-16B § 2, Proposed Original Sheet No. 314F.26.

[26] *Michigan Electric*, 117 FERC ¶ 61,314 at P 18, *order on reh'g*, 118 FERC ¶ 61,139 at P 13.

[27] Unlike rate cases in which cost projections are used to establish fixed rates, VEPCO's true-up mechanism will protect customers against unjust and unreasonable rates based on the projections.

34. VEPCO's projected costs will be trued-up to actual costs once such data becomes available. To calculate the True-Up Adjustment, VEPCO proposes to use actual cost-of-service data, which will either come from FERC Form No. 1 or from accounting data that is consistent with FERC Form No. 1 data.[28] VEPCO will compare the actual ATRR with the adjusted ATRR. The difference in these amounts, plus interest, equals the True-Up Adjustment. VEPCO proposes to post on PJM's website, by June 15, the adjusted ATRR for the previous year, along with the True-Up Adjustment. Parties will have until October 1 of each year to submit information requests to VEPCO concerning the adjusted ATRR and the True-Up Adjustment. VEPCO states that it will make a good faith effort to respond to such requests within 15 business days.

35. The protocols also provide for challenges to the True-Up Adjustment. Under VEPCO's proposed "Preliminary Challenge" provision, parties have until November 1 to notify VEPCO of any challenges to: (1) the True-Up Adjustment for the previous calendar year or (2) any Material Accounting Changes identified in the Annual Update. If changes are agreed upon, such changes will be posted on the PJM website by November 30 and incorporated into the ATRR for the following calendar year. If the differences among the parties are not resolved, parties may file a section 206 complaint with the Commission no later than December 16. The protocols limit the subject of the complaint to issues which were raised during the Preliminary Challenge stage of the proceeding.

36. The protocols specify that in any complaint proceeding or any proceeding initiated *sua sponte* by the Commission, VEPCO shall bear the burden of proving that it has reasonably calculated the True-Up Adjustment or reasonably made the Material Accounting Change. In addition, the protocols specify that the True-Up Adjustment and any Material Accounting Change, as well as the resulting ATRR, shall become final and no longer subject to challenge by the later of: (1) December 16 of the year in which they are posted if no complaint is filed and no proceeding is initiated *sua sponte* by the Commission, or (2) a final Commission order issued in response to a complaint or Commission-initiated proceeding to consider the True-Up Adjustment.

ii. <u>Comments and Protests</u>

37. The Virginia Consumer Counsel, VSCC Staff and Indicated Customers argue that VEPCO's proposal improperly attempts to create a new burden for customers by requiring them to file a complaint in order to trigger Commission scrutiny of changes in

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[28] VEPCO explains that it needs to use data other than that contained in FERC Form No. 1 because it relies on plant costs which use an average of 13 monthly balances. The balances for the first and last months will come from FERC Form No. 1, while the balances for the remaining 11 months will come from VEPCO's general ledger.

charges under the formula rates, which would then require the customers to bear the burden, as the complainant, of demonstrating that the existing rate or charge is unjust and unreasonable and what the change(s) to be made to the rate or charge should be and why. They contend that the utility, and not the ratepayer, has the burden of justifying its rates. Further, Indicated Customers object to a formal challenge being limited to issues raised in a preliminary challenge, even though issues may be discovered after the artificial cut-off date established by VEPCO's proposed timeline.

38. Protestors note that the amount of information to be provided by VEPCO under its proposal will be limited, and therefore will make it difficult to establish a factual basis to support a section 206 complaint. They also note that VEPCO's proposal limits parties' rights to challenge whether: (1) costs are prudent, (2) costs were properly recorded in the Uniform System of Accounts, or (3) the implementation of the formula rate is consistent with any changes in the requirements and contents of FERC Form No. 1 implemented since the adoption of the formula rate. Further, the protestors contend that VEPCO's proposed protocols limit the time allowed for analysis of changes in charges, which would artificially and unreasonably limit the right of an interested party to challenge the projected ATRR, adjusted ATRR, and True-Up Adjustment.

39. Protestors also raise a number of procedural issues. For example, Indicated Customers note that PJM cannot provide notice under the FPA to customers of a rate change; only the Commission can discharge this responsibility.[29] Protestors also state that the protocols do not provide procedures if VEPCO does not respond to requests for information or withholds relevant information. They also note that if VEPCO is not required, under section 205, to file its forward-looking ATRR or its true-up procedures, then VEPCO is not subject to the Deficiency Letter or suspension of its rates. Without such protections, protestors contend that the Commission will be deprived of the tools it needs to ensure that VEPCO's charges are not unjust, unreasonable, or unduly discriminatory.

40. Indicated Customers state that the timeline must be adequate to afford interested parties the opportunity to conduct the necessary review of the underpinning data, including time for discovery. Indicated Customers propose that in order to afford customers a meaningful opportunity for review of the projected ATRR and the True-Up Adjustment: (1) customer meetings should be scheduled at least 30 days after the posting, (2) customers should have at least 90 days after the customer meeting to submit information request to VEPCO, with 15 business days for VEPCO to respond; and (3) customers should have at least 30 days after the last response to submit a preliminary challenge.

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[29] Indicated Customers Protest at 18, *citing* 18 C.F.R. § 35.1(a), (c).

41. Indicated Customers note that VEPCO's protocols would require VEPCO to identify and customers to challenge Material Accounting Changes, which are changes in VEPCO's accounting policies and practices "that took effect in the preceding twelve months ending August 31"[30] that are reported in Notes 3 and 4 of VEPCO's Securities and Exchange Commission Form 10-Q. Indicated Customers note that this fails to take into account any changes VEPCO makes to conform to changes in FERC accounting policies. Indicated Customers note that changes to the formula rate are needed if there are changes to: (1) the reporting requirements in FERC Form No. 1; (2) the Uniform System of Accounts; (3) accounting policies, practices and procedures of the formula rate; and (4) the Commission's current policies with regard to cost allocation and rate designs. Indicated Customers contend that since the protocols do not address these fundamental predicates, VEPCO will be left with discretion as to when and how changes in the formula rate will reflect these predicates.

42. VSCC Staff notes that VEPCO's proposed True-Up Adjustment does not examine actual revenues collected by VEPCO under the formula rate. Rather, VSCC Staff contends that VEPCO proposes to compare projected costs with actual costs, not actual revenues. VSCC Staff argues that the Commission should require VEPCO to use actual revenues collected from customers in calculating the True-Up Adjustment.

43. VSCC Staff also notes that the True-Up Adjustment could serve to allow VEPCO to circumvent Virginia law regarding retail rates. Under the law, retail rates are capped until 2009. Because VEPCO will true-up its 2008 revenue requirement in 2010, retail ratepayers in Virginia could end up paying costs which were incurred during a period in which the retail rates were capped.

iii. <u>Commission Determination</u>

44. VEPCO's proposed True-Up Adjustment is consistent with the true-up mechanisms approved by the Commission for other companies.[31] To the extent that there is a disparity between actual revenues and actual costs which is not resolved through the True-Up Adjustment process set forth in VEPCO's protocols, parties may file a challenge with the Commission requesting that the inputs into the rate be reviewed. Between the information available from VEPCO's FERC Form No. 1 and that provided by VEPCO to its customers through the Annual Update and True-Up Adjustment, parties should have the information necessary to make such a challenge.

45. Several parties are concerned that VEPCO's proposed tariff language limits parties' and the Commission's rights to initiate a section 206 proceeding. The

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[30] Indicated Customers Protest at 33-34.

[31] *See, e.g.*, *PHI/BGE*, 115 FERC ¶ 61,066; *Xcel*, 121 FERC ¶ 61,284.

Commission does not object to a utility's efforts to resolve matters with its customers before resorting to a section 206 complaint. That process, however, may not impact the rights of any party which has standing to bring a complaint. VEPCO must revise its tariff to expand the definition of the term "Interested Party" to include all parties having standing under section 206, pursuant to its commitment in its April 2 Answer.[32]

46. VEPCO also proposes that there be a cut-off date for challenges to its rates but has not adequately justified why such a cut-off date is needed. In order for formula rates to work properly, they must allow for after-the-fact corrections and updates.[33] Parties should use due diligence to ensure that correct data is used; however, should an error be discovered, the inputs to the formula must be corrected and the formula re-calculated to prevent parties from being overcharged or undercharged. The Commission therefore requires VEPCO to remove the provision prohibiting parties from raising in a section 206 complaint any issues that it did not raise in its Preliminary Challenge; and remove the December 16 cut-off date for filing challenges.

47. We note that any challenge to the projected costs, True-Up Adjustment or Material Accounting Change would not require the complainant to meet the section 206 burden of proof. VEPCO continues to bear the burden of demonstrating the justness and reasonableness of the rate resulting from its application of the formula the Commission approves today, and specifically recognizes this burden in the applicable tariff sheets:

> In any Complaint proceeding or proceeding initiated *sua sponte* by the FERC challenging a True-Up Adjustment or a Material Accounting Change, VEPCO shall bear the burden of proving that it has reasonably calculated the True-Up Adjustment and/or reasonably adopted and applied the Material Accounting Change.[34]

48. We will not require VEPCO to file its True-Up Adjustment in an informational filing, as requested by various parties. VEPCO has committed, in its protocols, to provide information to its customers and to respond to information requests by such

[32] VEPCO April 2 Answer at 14.

[33] *See, e.g., San Diego Gas & Electric Co. v. Sellers of Energy and Ancillary Services*, 96 FERC ¶ 61,120, at 61,508 n.42 (2001); *Kern River Gas Transmission Co.*, 116 FERC ¶ 61,217 (2006).

[34] Attachment H-16B § 3(b), Proposed Original Sheet No. 314F.27.

customers.[35] We expect VEPCO to provide data to its customers relating to both the Annual Update and True-Up Adjustment in a timely manner, hold a customer meeting to explain the data, and respond to requests for further information.

49. We agree with Indicated Customers, however, that one day after a customer meeting is not sufficient time for parties to prepare comments, though we disagree that parties need 90 days. Within 30 days of the date of this order, VEPCO is required to make a compliance filing proposing a reasonable time period for parties to submit comments.

50. Indicated Shippers argue that only the Commission can provide notice that a rate has been changed. Indicated Shippers are correct that the formula can only be changed with proper notice. As noted above, the formula is the rate and the inputs that are applied as part of the formula are not part of the rate.[36] Therefore, Indicated Shippers' concerns are misplaced.

51. VSCC Staff did not explain how approving a wholesale formula rate would impact capped retail rates. The Commission is not making a predetermination of VEPCO's ability to collect retail rates under Virginia law. We find that VSCC Staff's concerns regarding the retail rate freeze in Virginia is beyond the scope of this proceeding.

2. <u>Issues Related to Formula Inputs</u>

a. <u>RTO Membership Adder</u>

i. <u>VEPCO's Proposal</u>

52. VEPCO requests Commission approval of a 50 basis point adder to its proposed ROE for its continued participation in the PJM RTO. VEPCO notes that the Commission has consistently authorized a 50 basis point adder in order to encourage RTO membership and has specifically authorized the adder for RTO participants that continue their participation. VEPCO contends that its requested base ROE of 11.73 percent plus the RTO incentive adder results in an ROE of 12.23 percent, which falls within the zone of reasonableness.

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[35] Attachment H-16B § 2, Proposed Original Sheet No. 314F.26.

[36] *PJM Interconnection, LLC*, 110 FERC ¶ 61,053, at P 120 (2005), *Appalachian Power Co.*, 23 FERC ¶ 61,032, at 61,088 (1983).

ii. Comments and Protests

53. The North Carolina Agencies and VSCC Staff oppose the 50 basis point adder for VEPCO's continued participation in PJM. They note that that Order No. 679 specifies that the 50 basis point incentive adder is to reward utilities for voluntary membership in an RTO.[37] However, they note that VEPCO's membership in PJM is not voluntary; rather it was required by the Virginia Electric Utility Restructuring Act[38] and the VSCC order approving VEPCO's integration into PJM.[39] Therefore, they contend, that to reward VEPCO for its obligatory participation in PJM rewards VEPCO's shareholders at the expense of Virginia's ratepayers.

iii. Commission Determination

54. We find that VEPCO's proposal to increase its ROE by 50 basis points for continued participation in PJM is just and reasonable and not unduly discriminatory. Section 219 of the FPA specifically provides that the Commission shall provide for incentives to each transmitting utility that joins an RTO. The consumer benefits, including reliable grid operation, provided by such organizations are consistent with the purpose of section 219. As we stated in Order No. 679-A, we will authorize incentive-based rate treatment for public utilities that continue to be a member of an RTO.[40] This decision to provide incentives for RTO participation is based on the policy of encouraging utilities to join and remain in an RTO.[41] Accordingly, we reject requests that VEPCO not be rewarded for its continued membership in PJM. In addition, we also deny the relief requested by the parties as this argument is a collateral attack on Order No. 679-A.[42] Finally, we note that the level of the requested incentive, 50 basis points, is the same as that approved for similar utilities, including BG&E.[43]

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[37] *Citing* Order No. 679 at P 83 and Order No. 679-A at P 331.

[38] VSCC Protest at 5, *citing* Va. Code § 56-577.

[39] VSCC Protest at 5, *citing* VSCC Case No. PUE-2000-0055 (November 10, 2004).

[40] Order No. 679-A at P 86.

[41] *AEP*, 121 FERC ¶ 61,245 at P 10 (denying rehearing of objections to 50 basis point ROE adder when participation in the RTO was a merger condition, not voluntary).

[42] Order No. 679-A at P 79.

[43] *Baltimore Gas and Electric Co.*, 120 FERC ¶ 61,084, at P 31 (2007), *reh'g pending*.

b. Return on Equity

i. VEPCO's Proposal

55. VEPCO's formula rate incorporates a base ROE of 11.73 percent, which is the midpoint of its proposed range of reasonableness of 7.5 percent to 15.61 percent. VEPCO states that this range of reasonableness was determined using the one-step DCF methodology with benchmarks for sustainable growth rate estimated from Value Line information and security analysts' long-term earnings growth forecasts. VEPCO used a proxy group of transmission owners within PJM,[44] excluding: (1) those utilities that are not currently paying cash dividends; (2) utilities that have announced a merger during the six-month period used to calculate the dividend yields; (3) utilities primarily operating as natural gas companies; (4) utilities that do not have both an IBES (International Brokers Estimation System) growth rate and *Value Line* data; and (5) one utility whose high-end cost of equity was more than 100 basis points above the cost of equity of any other utility in its proposed proxy group.

ii. Comments and Protests

56. VSCC Staff contends that VEPCO's proposed ROE of 11.73 percent is too high because (1) a formula rate reduces financial risk by allowing for more timely recovery of costs; (2) the true-up mechanism permits ratepayer funds to be used as a source of financing; and (3) Virginia law requires that all of VEPCO's costs for transmission service provided by PJM must be deemed prudent. VSCC Staff notes that the VSCC has determined that the ROE for Virginia jurisdictional utilities is approximately 10 percent. VSCC Staff recommend that the issue of the appropriate ROE be set for hearing.

57. Indicated Customers also contend that the proposed ROE does not reflect the appropriate level of risk for VEPCO because (1) electric transmission utilities, like VEPCO, are less risky than electric generating utilities, such as many of the companies in VEPCO's proxy group; (2) the conversion from stated rates to formula rates eliminates uncertainty regarding the collection of prudently incurred actual costs, including equity costs; and (3) VEPCO's parent carries a lower risk than VEPCO's proposed proxy group. Indicated Customers further argue that Constellation and Exelon should be excluded from the proxy group because they provide an upward bias. In addition, Indicated Customers contend that VEPCO incorrectly relies on the midpoint of the low and high results of the

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[44] VEPCO's proposed proxy group consists of American Electric Power Company, Inc. (AEP), Consolidated Edison, Inc. (ConEd), Constellation Energy Group, Inc. (Constellation), VEPCO's parent – Dominion Resources, Inc., DPL, Inc. (DPL), Exelon Corp. (Exelon), First Energy Corp. (FirstEnergy), PHI, PPL Corp. (PPL), and Public Service Enterprise Group, Inc. (Public Service).

range of reasonableness. They recommend that the median be used,[45] and recommend a base ROE of 10.06 percent. Finally, in their response to VEPCO's February 29 Filing, Indicated Customers request that the Commission set the issue of ROE for hearing and not summarily address the issues.

iii. Commission Determination

58. We deny VEPCO's request for an ROE of 12.23 percent (a base ROE of 11.73 percent as discussed below plus a 50 basis point ROE adder for continued RTO membership) and find that, consistent with our precedent, the appropriate ROE to be applied is 10.9 percent, plus the 50 basis point ROE adder for continued RTO membership. This yields a combined ROE of 11.4 percent. As discussed below, first, we find that VEPCO's proxy group does not reflect our current proxy group policies as set forth in *PATH*.[46] Second, the Commission's precedent on ROE for individual companies requires the use of the median of the calculated ROE of companies in the proxy group, rather than the midpoint used by VEPCO.

59. The Supreme Court has provided guidance in two often-cited decisions regarding the range of allowed returns that may be permitted in a particular case. In *Bluefield*, the court stated that the approved return should be "reasonably sufficient to assure confidence in the financial soundness of the utility, and should be adequate, under efficient and economical management, to maintain and support its credit, and enable it to raise the money necessary for the proper discharge of its public duties."[47] In *Hope*, the court stated that the return to the equity owner should be commensurate with returns on investment in other enterprises having corresponding risks.[48]

60. The Commission has found that a 15-company proxy group that includes utilities in PJM, ISO-NE and NYISO is a good starting point for companies in PJM to develop an individual proxy that takes into account comparable risks.[49] VEPCO limited its proposed proxy group to utilities within PJM. However, VEPCO did not provide any evidence as to why comparable utilities should be limited to PJM as opposed to utilities in the

[45] *Citing Northwest Pipeline Corp.*, 99 FERC ¶ 61,305, at 62,276 (2002).

[46] *Potomac-Appalachian Transmission Highline, L.L.C.*, 122 FERC ¶ 61,188 at P 93-103 (2008) (*PATH*).

[47] *Bluefield Water Works & Improvement Co. v. Public Service Commission of West Virginia*, 262 U.S. 679, 693 (1923).

[48] *FPC v. Hope Natural Gas Co.*, 320 U.S. 591, 603 (1944).

[49] *PATH*, 122 FERC ¶ 61,188.

northeastern United States. Consistent with our holdings in *PATH* and other cases, we find that the broader region more accurately reflects the energy markets in which VEPCO competes. Therefore, the proxy group should be expanded to include entities within the interrelated RTO markets operated by PJM, ISO-NE and the New York ISO whose risk is comparable to VEPCO.[50]

61. In order to ensure that the entities in its proxy group are of comparable risk, VEPCO applied the following screening criteria as part of its analysis and excluded: (1) those utilities that are not currently paying cash dividends; (2) utilities that have announced a merger during the six-month period used to calculate the dividend yields; (3) utilities primarily operating as natural gas companies; (4) utilities that do not have both an IBES growth rate and Value Line data, and (5) one utility whose high-end cost of equity was more than 100 basis points above the cost of equity of any other utility in its proposed proxy group. However, while VEPCO states that it applied a screen for risk, VEPCO's proxy group does not sufficiently screen for risk, because as discussed below it includes various companies whose corporate credit ratings are not comparable. Further, VEPCO has not sufficiently screened its proxy group for unsustainable growth rates.

62. We agree with protesters that, consistent with *Hope*, we must consider whether the proxy group is composed of companies with comparable risk to that of VEPCO. It is reasonable to use the proxy companies' corporate credit rating as a good measure of investment risk, since this rating considers both financial and business risk. At the time of its filing, VEPCO's parent company's Standard and Poor's (S&P) corporate credit rating was BBB.[51] Indicated Customers state that, since VEPCO's filing, S&P has upgraded the crediting rating of VEPCO's parent company to A-.[52] They accordingly argue that the proxy group should be limited to utilities with credit ratings within one step above and below the current credit rating of VEPCO's parent. This would limit the proxy group to utilities with credit ratings of BBB+, A-, and A. However, VEPCO responds that although S&P upgraded the credit rating, the other two major credit rating agencies, Fitch Ratings (Fitch) and Moody's Investor Services (Moody's), have not altered their credit ratings for VEPCO's parent company. Fitch's most recent rating is BBB+, which is the equivalent of an S&P rating of BBB+. Moody's most recent rating is Baa2, which is the equivalent of an S&P rating of BBB.

[50] *PATH*, 122 FERC ¶ 61,188 at P 95.

[51] *See* October 25 Filing, Exhibit No. DVP-12 at 10 (Direct Testimony of Dr. Michael J. Vilbert).

[52] Indicated Customers March 21 Supplemental Protest, Attachment B at 8 (Affidavit of J. Bertram Solomon); *see also* VEPCO April 2 Answer at 7-8.

63. In these circumstances, we find that the appropriate credit rating screening criterion to use in this case is to require that each utility included in the proxy group have corporate credit ratings from BBB to A-, or the equivalent Moody's rating. Consistent with our holdings in other cases, this limits the proxy companies to one of three possible credit ratings,[53] and in this case each of those credit ratings is currently applied to VEPCO's parent by a major credit rating agency. We accordingly exclude ConEd, FPL and NSTAR from the proxy group, because their credit ratings are all higher than A-. We also exclude UIL Holdings and Central Vermont Public Service because their credit ratings are below BBB or the Moody's equivalent.

64. We also agree with Indicated Customers that the inclusion of Constellation, Exelon, and Public Service in the proxy group is inappropriate because, as we found in *PATH*,[54] their current growth rates are too high to be sustainable over time and therefore do not meet threshold tests of economic logic. In addition, we find that VEPCO's parent company should be excluded from the proxy group, because its cost of equity is below its cost of debt.[55]

65. Based on these findings, we find that VEPCO's proxy group should include the following six utilities: AEP, DPL, FirstEnergy, Northeast Utilities, Pepco Holdings, and PPL. We find that, with these revisions to VEPCO's proposed proxy group, the resulting proxy group is of comparable risk to VEPCO.

66. In the instant proceeding, we are determining the appropriate ROE for an individual utility of average risk, rather than a group of utilities. We agree with Indicated Customers that, in this circumstance, use of the median rather than the midpoint is appropriate because the median "best represents the central tendency in a proxy group with a skewed distribution of returns."[56] As we found in Opinion No. 501, "using the median also has the advantage of taking into account more of the companies in a proxy group rather than only those at the top and bottom."[57]

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[53] *PATH*, 122 FERC ¶ 61,188 at P 98.

[54] *Id.* at P 100.

[55] *See Southern California Edison Co.*, Opinion No. 445, 92 FERC ¶ 61,070, at 61,266 (2000); *PATH*, 122 FERC ¶ 61,188 at P 101.

[56] *Golden Spread Electric Cooperative, Inc. v. Southwestern Public Service Co.*, 123 FERC ¶ 61,047, at P 63 (2008), *citing Northwest Pipeline Corp.*, 99 FERC ¶ 61,305, at 62,276 (2002); *see also Midwest Independent Transmission System Operator Corp.*, 106 FERC ¶ 61,302, at P 10 (2004).

[57] *Golden Spread*, 123 FERC ¶ 61,047 at P 64.

67. Using the dataprepared by Dr. Solomon and revising the proxy group to reflect the companies selected as appropriate for VEPCO yields a range of ROE from 7.9 percent to 14.9 percent, with a median of 10.9 percent.[58] As noted above, consistent with our finding in *Golden Spread*, we find that use of the median ROE of 10.9 percent is appropriate for VEPCO, resulting in an 11.4 percent ROE once the 50 basis point incentive adder for continued RTO membership is included.

68. Finally, the fact the VSCC may have found that the appropriate ROE for the retail services of utilities subject to its jurisdiction is about 10 percent is not relevant to our determination of the appropriate ROE to include in VEPCO's rates for the interstate services subject to our jurisdiction. The Commission has conducted an ROE analysis utilizing comparable companies consistent with our precedent which supports the rate of return we are accepting.

c. Capital Structure

i. VEPCO's Proposal

69. VEPCO proposes to use a projected capital structure of 41.2 percent debt and 58.8 percent common equity.[59] This is comprised of the average balance for the 2008 calendar year, using VEPCO's projected beginning and year-end debt and equity balances.[60] VEPCO proposes to true-up the debt-equity ratio based on actual costs as reflected in the previous year's FERC Form No. 1, except that ROE will remain at 12.23 percent.

ii. Comments and Protests

70. Indicated Customers and North Carolina Agencies contend that VEPCO's proposed capital structure is based on unsubstantiated projections and that the proposed 58.8 percent equity ratio is high compared to the equity ratios of other electric utilities and given current economic conditions. Indicated Customers note VEPCO's 2006

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[58] Supplemental Protest, Exhibit No. INC-1. The median is determined utilizing the methodology accepted by the Commission in *Golden Spread.* First, the average of the high and low ROEs for each of the six proxy companies is calculated. Second, the averaged ROEs for the two utilities which fall within the middle of the range of the high-low average is then averaged. This results in a median of 10.9 percent. *See Golden Spread Electric Cooperative, Inc. v. Southwestern Public Service Co.,* 63 FERC ¶ 63,043 at P 100 and Exhibit No. S-1, Schedule No. 10.

[59] Exhibit No. DVP-8, at 3, lines 120-122.

[60] Bailey Testimony at 9.

average common equity ratio was 53 percent while the equity ratio for VEPCO's proxy group utilities was 46 percent for the year ending December 31, 2007. They further note that VEPCO's parent had an equity ratio of 42 percent as of December 31, 2007.

71. North Carolina Agencies contend that VEPCO's formula rate allows VEPCO a return on equity on an "ever-changing" equity ratio. North Carolina Agencies object to the "floating" equity ratio and recommend that the issue be set for hearing.

72. Indicated Customers are concerned that the proposed true-up would provide VEPCO's parent company an opportunity to potentially manipulate VEPCO's regulated capital structure to its overall corporate benefit and subsidize unregulated subsidiaries at the expense of the regulated formula rate customers. Indicated Customers therefore recommend that VEPCO's formula rate contain a 50 percent cap on its common equity ratio so that a "manipulated, excessive, actual common equity ratio" cannot be used just because it was the actual reported in the company's FERC Form No 1.

iii. Commission Determination

73. We agree with protestors that VEPCO has not supported its proposed capital structure. In fact, VEPCO has provided no explanation as to why it proposes a hypothetical debt/equity ratio of 41.2/58.8. The Commission has a strong preference for using the actual capital structure of the company in developing its rate of return, unless there is an overriding reason not to do so.[61] Further, using FERC Form No. 1 data is consistent with Commission precedent for PJM transmission owners with formula rates. Because VEPCO did not provide an overriding reason to use a hypothetical capital structure, we will require VEPCO to file revised tariff sheets within 30 days of the date of this order to reflect the capital structure for 2006, as shown in its FERC Form No. 1 data.[62]

3. Cost of Service Issues

74. The Commission reviews certain issues related to VEPCO's inputs into the formula rate for 2008 rates because customers have not had the opportunity to review this data and challenge it through the Annual Update process contained in VEPCO's tariff. We note that in the future, we expect that issues related to the cost-of-service inputs into

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[61] *Transcontinental Gas Pipeline Corp.*, 84 FERC ¶ 61,084 (1998); *Allegheny Power*, Opinion No. 469, 106 FERC ¶ 61,251, at P 27 (2004) *citing* 103 FERC ¶ 63,001, at P 28 (2003).

[62] *See, e.g.*, PJM OATT, FERC Electric Tariff, Sixth Rev. Vol. No. 1, Attachment H-1 or H-2.

the formula rate will be resolved through VEPCO's Annual Update and True-Up Adjustment process, with recourse to the Commission only when the parties cannot resolve the issues themselves.

75. In response to VEPCO's October 25 Filing, the Commission issued a Deficiency Letter requesting additional information on certain inputs to the 2008 rate. We find that VEPCO's responses to the following issues are adequate: (1) balances of Account 283, *Accumulated Deferred Income Taxes – Other*; [63] (2) property insurance; (3) inclusion of revenue credits in VEPCO's ATRR; (4) increase in transmission operations and maintenance costs; (5) expenses for wages and salaries; (6) amount to be included in Account No. 165, Prepayments; and (7) amortization of software as part of intangible plant amortization. We also accept VEPCO's proposal for cash working capital as just and reasonable because it conforms to our policy which allows for 45 days or one-eighth of a year's operations and maintenance expenses, less purchased power costs and is consistent with our finding on cash working capital in *PATH*.[64]

4. Request for Waivers

a. VEPCO's Proposal

76. VEPCO requests waiver of section 35.13 of the Commission's regulations, including waiver of the full Period I and Period II data requirements and waiver of the requirement in section 35.13(a)(2)(iv), to determine if and the extent to which a proposed change constitutes a rate increase based on Period I-Period II rates and billing determinants. VEPCO contends that waiver is appropriate because of its use of filed FERC Form No. 1 data and the fact that VEPCO is proposing a formula rate rather than a stated rate. VEPCO also requests that the Commission grant any other necessary waivers.

b. Comments & Protests

77. Indicated Customers argue that VEPCO's justification for the waiver of section 35.13 of the Commission's regulations does not apply here. Indicated Customers explain that in *PHI/BGE*, the Commission reasoned that such Period I and Period II data may not be necessary where the transmission owner is establishing a formula rate using FERC Form No. 1 data. However, Indicated Customers contend that VEPCO's witness, Mr. Bailey, in his supporting testimony, explains that some of the formula input data is not

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[63] October 25 Filing at Exhibit No. DVP-8, page 7.

[64] *Trans-Elect NTD PATH 15, LLC*, 117 ¶ 61,214, at P 32, 39-43 (2006); *see also PATH*, 122 FERC ¶ 61,188 at P 158.

available from FERC Form No. 1.[65] Indicated Customers state that VEPCO has provided Attachment 5 to its filing in order to compensate for the missing data which Mr. Bailey describes as "similar to" statements that would be submitted per section 35.13.[66] Indicated Customers argue that the purpose of requiring detailed cost of service data is to allow the Commission and interested parties the opportunity to verify the rates to be charged. Rather than rely on a blend of FERC Form No. 1 data and attachments that are "similar to" what would be required in the absence of detailed cost information, Indicated Customers urge the Commission to direct VEPCO to comply with the requirements of section 35.13.

c. Commission Determination

78. We will grant VEPCO's requests for waiver to the extent such requests have not been made moot by its responses to the Deficiency Letter. In its responses to the Deficiency Letter,[67] VEPCO provided Statements AA through AY for Period I based on calendar year 2006 that correlates to FERC Form No. 1 data and for Period II that correlates with Exhibit No. DVP-8. VEPCO also provided revenue data as required in Statement BG and Statement BH of section 35.13 of the Commission's regulations. While we find that the provision of these statements (or the data required by these statements) moots VEPCO's requests for waivers as they relate to those statements in section 35.13 of the Commission's regulations, the requests for waivers are still relevant to those provisions of section 35.13 with which VEPCO has not complied. In this instance, we will grant waivers of those remaining provisions of section 35.13 as VEPCO has provided sufficient information to allow the Commission and interested parties the opportunity to verify the rates to be charged for 2008, which we find adequately addresses the concern raised by Indicated Customers.

5. Coordination with Schedule 12 Proceeding

a. VEPCO's Proposal

79. VEPCO requests an effective date of January 1, 2008 for its formula rate.

b. Comments and Protests

80. BG&E, along with PSE&G and PHI Companies, urge the Commission to approve an uncontested settlement containing revised Schedule 12 cost allocations (Schedule 12

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[65] *Citing* Bailey Testimony at 13.

[66] *Id.*

[67] *See* February 29 Filing and January 18 Filing.

Costs Settlement) before VEPCO's formula rate proposal is allowed to go into effect.[68] BG&E explains that all of the Schedule 12 cost allocations that VEPCO is currently reflecting in its formula are from PJM filings that were protested by numerous parties and are to be superseded by the Schedule 12 Costs Settlement filed on September 14, 2007. BG&E states that if the proposal takes effect prior to the Commission's approval and implementation of the Schedule 12 Costs Settlement, then PJM will have to invoice its various rate zones the allocations reflected in the October 25 Filing, only to have to subsequently re-bill these amounts with refunds and retroactive surcharges, as appropriate, once the Schedule 12 Costs Settlement is approved. BG&E argues that this allocation/reallocation scenario is contrary to the public interest, will result in unjust and unreasonable rates, and is administratively inefficient and burdensome. BG&E argues that should this scenario occur, the BG&E rate zone load would be forced to subsidize, through a virtual loan, the agreed-upon Responsible Customers in the interim period between the effective date of the formula rate and the effective date of the Schedule 12 Costs Settlement. BG&E suggests that the most rational approach is for the Schedule 12 Costs Settlement to be approved and effectuated and then to allow the formula rates to go into effect, subject to refund and based on the outcome of a final Commission determination.

81. The Maryland Commission states that recovery of costs for VEPCO transmission projects through Schedule 12 may result in Maryland sharing in a portion of the costs for certain projects through the formula rates in the present proceeding. The Maryland Commission requests that the Commission clarify that the allocation of costs for VEPCO transmission projects to the VEPCO Zone and to other participants in the PJM market through the VEPCO formula rate are (1) subject to any revisions to the PJM Schedule 12 allocations as determined by the Commission and (2) just and reasonable.

c. <u>Commission Determination</u>

82. Protestors request that the tariff sheets associated with the Schedule 12 Costs Settlement be accepted for filing before the tariff sheets establishing VEPCO's formula rate. Alternatively, BG&E requests that the tariff sheets is this proceeding be conditioned upon the acceptance of the tariff sheets in the RTEP proceeding. We deny both requests and accept the tariff sheets submitted by VEPCO in this proceeding, subject to conditions, effective January 1, 2008. We are required by statute to act on VEPCO's filing by April 29, 2008, 60 days after VEPCO filed its last response to the Deficiency

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[68] Alternatively, BG&E opposes VEPCO's request to have its formula rate become effective on January 1, 2008 unless the Schedule 12 Costs Settlement is allowed to go into effect prior to January 1, 2008, and VEPCO and PJM concur that no invoices will be rendered for Schedule 12 costs until VEPCO updates its formula rate filing to reflect the approved Schedule 12 Costs Settlement.

Letter. The Schedule 12 Costs Settlement is pending, but does not require action by a specific date. Although the proceedings may have overlapping issues, we are considering each proceeding on its own merits. Our regulations recognize that the acceptance of tariff sheets in one proceeding may require that tariff sheets accepted in another proceeding be re-filed. In Order No. 614, we referred to such tariff sheets as "retroactive" sheets.[69] Should PJM be required to surcharge or refund ratepayers on VEPCO's behalf, as a result of re-filing tariff sheets, it will apply interest in accordance with our regulations.[70]

The Commission orders:

(A) VEPCO's revised tariff sheets to the PJM OATT are accepted for filing effective January 1, 2008, subject to revision based on the compliance filing.

(B) VEPCO is ordered to file revised tariff sheets to PJM's OATT within 30 days of this order, as discussed more fully above.

By the Commission. Commissioner Kelly dissenting in part with a separate statement to be issued at a later date.

(S E A L)

Kimberly D. Bose,
Secretary.

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[69] *Designation of Electric Rate Schedule Sheets*, (Order No. 614), 65 Fed. Reg. 18,221 (March 21, 2000) FERC Stats. & Regs. ¶ 31,096, at 31,520 (2000).

[70] 18 C.F.R. § 35.19a (2007).

Document Content(s)

(20) Virginia Electric and Power Company

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0217	Upgrade Mt. Storm - Doubs 500kV	As specified in Attachment 7 to Appendix A of Attachment H-16A and under the procedures detailed in Attachment H-16B	AEC (2.05%) / AEP (16.79%) / APS (5.96%) / BGE (4.91%) / ComEd (16.11%) / Dayton (2.53%) / DL (2.08%) / DPL (2.93%) / Dominion (13.22%) / JCPL (4.57%) / ME (2.04%) / NEPTUNE* (0.47%) / PECO (6.10%) / PENELEC (2.09%) / PEPCO (4.74%) / PPL (5.16%) / PSEG (7.58%) / RE (0.30%) / UGI (0.14%) / ECP** (0.23%)
b0222	Install 150 MVAR capacitor at Loudoun 500 kV	As specified in Attachment 7 to Appendix A of Attachment H-16A and under the procedures detailed in Attachment H-16B	AEC (2.05%) / AEP (16.79%) / APS (5.96%) / BGE (4.91%) / ComEd (16.11%) / Dayton (2.53%) / DL (2.08%) / DPL (2.93%) / Dominion (13.22%) / JCPL (4.57%) / ME (2.04%) / NEPTUNE* (0.47%) / PECO (6.10%) / PENELEC (2.09%) / PEPCO (4.74%) / PPL (5.16%) / PSEG (7.58%) / RE (0.30%) / UGI (0.14%) / ECP** (0.23%)

* Neptune Regional Transmission System, LLC
** East Coast Power, L.L.C.

Virginia Electric and Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0223	Install 150 MVAR capacitor at Asburn 230 kV	As specified in Attachment 7 to Appendix A of Attachment H-16A and under the procedures detailed in Attachment H-16B	BG&E (18%) / DP&L (5%) / Dominion (25%) / JCP&L (6%) / PECO (10%) / PEPCO (19%) / PP&L (7%) / PSE&G (10%)
b0224	Install 150 MVAR capacitor at Dranesville 230 kV	As specified in Attachment 7 to Appendix A of Attachment H-16A and under the procedures detailed in Attachment H-16B	BG&E (18%) / DP&L (5%) / Dominion (25%) / JCP&L (6%) / PECO (10%) / PEPCO (19%) / PP&L (7%) / PSE&G (10%)
b0225	Install 33 MVAR capacitor at Possum Pt. 115 kV	As specified in Attachment 7 to Appendix A of Attachment H-16A and under the procedures detailed in Attachment H-16B	BG&E (22%) / Dominion (30%) / PECO (12%) / PEPCO (23%) / PSE&G (13%)

* Neptune Regional Transmission System, LLC
** East Coast Power, L.L.C.

Virginia Electric and Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0226	Install 500/230 kV transformer at Clifton and Clifton 500 kV 150 MVAR capacitor	As specified in Attachment 7 to Appendix A of Attachment H-16A and under the procedures detailed in Attachment H-16B	AE (1%) / BG&E (9%) / DP&L (2%) / Dominion (61%) / JCP&L (2%) / Met-Ed (1%) / PECO (4%) / PEPCO (13%) / PP&L (3%) / PSE&G (4%)
b0227	Install 500/230 kV transformer at Bristers; build new 230 kV Bristers-Gainsville circuit, upgrade two Loudoun-Brambleton circuits		AEC (4%) / APS (3%) / BGE (17%) / DPL (6%) JCPL (9%) / METED (4%) / NEPTUNE (1%) / PECO (12%) / PENELEC (2%) / PEPCO (19%) / PPL (9%) / PSEG (13%) / RE (1%)
b0227.1	Loudoun Sub – upgrade 6-230 kV breakers		AEC (4%) / APS (3%) / BGE (18%) / DPL (6%) / JCPL (9%) / ME (4%) / PECO (12%) / PEPCO (20%) / PPL (10%) / PSEG (14%)

* Neptune Regional Transmission System, LLC
** East Coast Power, L.L.C.

Virginia Electric and Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0231	Install Suffolk 500/230 kV, reconfigure Suffolk 500 kV, reconfigure Yadkin 500 kV, connect Septra-Fentress 500 kV into Yadkin 500 kV		AEC (2.05%) / AEP (16.79%) / APS (5.96%) / BGE (4.91%) / ComEd (16.11%) / Dayton (2.53%) / DL (2.08%) / DPL (2.93%) / Dominion (13.22%) / JCPL (4.57%) / ME (2.04%) / NEPTUNE* (0.47%) / PECO (6.10%) / PENELEC (2.09%) / PEPCO (4.74%) / PPL (5.16%) / PSEG (7.58%) / RE (0.30%) / UGI (0.14%) / ECP** (0.23%)†
b0231	Install Suffolk 500/230 kV, reconfigure Suffolk 500 kV, reconfigure Yadkin 500 kV, connect Septra-Fentress 500 kV into Yadkin 500 kV		Dominion (100%)††
b0231.1	Upgrade 1-230 kV breaker at Yadkin substation		Dominion (100%)
b0232	Install 150 MVAR capacitor at Lynnhaven 230 kV		Dominion (100%)
b0233	Install 150 MVAR capacitor at Landstown 230 kV		Dominion (100%)
b0234	Install 150 MVAR capacitor at Greenwich 230 kV		Dominion (100%)
b0235	Install 150 MVAR capacitor at Fentress 230 kV		Dominion (100%)

* Neptune Regional Transmission System, LLC
** East Coast Power, L.L.C.
†Cost allocations associated with Regional Facilities and Necessary Lower Voltage Facilities associated with the project
††Cost allocations associated with below 500 kV elements of the project

Issued By: Craig Glazer Effective: October 19, 2006
Vice President, Federal Government Policy
Issued On: May 21, 2007
Filed to comply with order of the Federal Energy Regulatory Commission, Docket Nos. ER06-456 et al., issued April 19, 2007, 119 FERC ¶ 61,067 (2007).

Virginia Electric and Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0307	Reconductor Endless Caverns – Mt. Jackson 115 kV		AEC (3%) / APS (19%) BGE (14%) / (DPL (5%) / Dominion (8%) / JCPL (6%) / METED (3%) / PECO (9%) / PEPCO (16%) / PPL (7%) / PSEG 10%)
b0308	Replace L breaker and switches at Endless Caverns 115 kV		APS (22%) / BGE (14%) / Dominion (27%) / PECO (10%) / PEPCO (16%) / PSEG (11%)
b0309	Install SPS at Earleys 115 kV		Dominion (100%)
b0310	Reconductor Club House – South Hill and Chase City – South Hill 115 kV		Dominion (100%)
b0311	Reconductor Idylwood to Arlington 230 kV		Dominion (100%)
b0312	Reconductor Gallows to Ox 230 kV		AEC (2%) / APS (4%) / BGE (5%) / DPL (3%) / Dominion (60%) / JCPL (4%) / METED (2%) / PECO (5%) / PEPCO (6%) / PPL (4%) / PSEG (5%)

Virginia Electric and Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0325	Install a 2nd Everetts 230/115 kV transformer		Dominion (100%)
b0326	Uprate/resag Remington-Brandywine-Culppr 115 kV		Dominion (100%)
b0327	Build 2nd Harrisonburg – Valley 230 kV		AEC (2%) / APS (20%) / BGE (8%) / DPL (3%) / Dominion (33%) / JCPL (5%) / ME (2%) / PECO (6%) / PENELEC (1%) / PEPCO (8%) / PPL (5%) / PSEG (7%)
b0328.1	Build new Meadow Brook – Loudoun 500 kV circuit (30 of 50 miles)		AEC (2.05%) / AEP (16.79%) / APS (5.96%) / BGE (4.91%) / ComEd (16.11%) / Dayton (2.53%) / DL (2.08%) / DPL (2.93%) / Dominion (13.22%) / JCPL (4.57%) / ME (2.04%) / NEPTUNE* (0.47%) / PECO (6.10%) / PENELEC (2.09%) / PEPCO (4.74%) / PPL (5.16%) / PSEG (7.58%) / RE (0.30%) / UGI (0.14%) / ECP** (0.23%)

* Neptune Regional Transmission System, LLC
** East Coast Power, L.L.C.

Virginia Electric and Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0328.3	Upgrade Mt. Storm 500 kV substation		AEC (2.05%) / AEP (16.79%) / APS (5.96%) / BGE (4.91%) / ComEd (16.11%) / Dayton (2.53%) / DL (2.08%) / DPL (2.93%) / Dominion (13.22%) / JCPL (4.57%) / ME (2.04%) / NEPTUNE* (0.47%) / PECO (6.10%) / PENELEC (2.09%) / PEPCO (4.74%) / PPL (5.16%) / PSEG (7.58%) / RE (0.30%) / UGI (0.14%) / ECP** (0.23%)
b0328.4	Upgrade Loudoun 500 kV substation		AEC (2.05%) / AEP (16.79%) / APS (5.96%) / BGE (4.91%) / ComEd (16.11%) / Dayton (2.53%) / DL (2.08%) / DPL (2.93%) / Dominion (13.22%) / JCPL (4.57%) / ME (2.04%) / NEPTUNE* (0.47%) / PECO (6.10%) / PENELEC (2.09%) / PEPCO (4.74%) / PPL (5.16%) / PSEG (7.58%) / RE (0.30%) / UGI (0.14%) / ECP** (0.23%)

* Neptune Regional Transmission System, LLC
** East Coast Power, L.L.C.

Virginia Electric and Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0329	Build Carson – Suffolk 500 kV, install 2nd Suffolk 500/230 kV transformer & build Suffolk – Fentress 230 kV circuit		AEC (2.05%) / AEP (16.79%) / APS (5.96%) / BGE (4.91%) / ComEd (16.11%) / Dayton (2.53%) / DL (2.08%) / DPL (2.93%) / Dominion (13.22%) / JCPL (4.57%) / ME (2.04%) / NEPTUNE* (0.47%) / PECO (6.10%) / PENELEC (2.09%) / PEPCO (4.74%) / PPL (5.16%) / PSEG (7.58%) / RE (0.30%) / UGI (0.14%) / ECP** (0.23%)†
b0329	Build Carson – Suffolk 500 kV, install 2nd Suffolk 500/230 kV transformer & build Suffolk – Fentress 230 kV circuit		Dominion (100%)††
b0330	Install Crewe 115 kV breaker and shift load from line 158 to 98		Dominion (100%)
b0331	Upgrade/resag Shell Bank – Whealton 115 kV (Line 165)		Dominion (100%)

* Neptune Regional Transmission System, LLC
** East Coast Power, L.L.C.
†Cost allocations associated with Regional Facilities and Necessary Lower Voltage Facilities associated with the project
††Cost allocations associated with below 500 kV elements of the project

Virginia Electric and Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0332	Uprate/resag Chesapeake – Cradock 115 kV		Dominion (100%)
b0333	Replace wave trap on Elmont – Replace (Line #231)		Dominion (100%)
b0334	Uprate/resag Iron Bridge-Walmsley-Southwest 230 kV		Dominion (100%)
b0335	Build Chase City – Clarksville 115 kV		Dominion (100%)
b0336	Reconductor one span of Chesapeake – Dozier 115 kV close to Dozier substation		Dominion (100%)
b0337	Build Lexington 230 kV ring bus		Dominion (100%)
b0338	Replace Gordonsville 230/115 kV transformer for larger one		AEC (2%) / APS (3%) / BGE (11%) / DPL (4%) / Dominion (39%) / JCPL (5%) / ME (2%) / PECO (7%) / PENELEC (1%) / PEPCO (12%) / PPL (6%) / PSEG (8%)
b0339	Install Breaker at Dooms 230 kV Sub		BGE (9%) / Dominion (69%) / PECO (5%) / PEPCO (11%) / PSEG (6%)
b0340	Reconductor one span Peninsula – Magruder 115 kV close to Magruder substation		Dominion (100%)
b0341	Install a breaker at Northern Neck 115 kV	As specified in Attachment 7 to Appendix A of Attachment H-16A and under the procedures detailed in Attachment H-16B	Dominion (100%)
b0342	Replace Trowbridge 230/115 kV transformer		Dominion (100%)
b0403	2nd Dooms 500/230 kV transformer addition	As specified in Attachment 7 to Appendix A of Attachment H-16A and under the procedures detailed in Attachment H-16B	AEC (1%) / APS (2%) / BGE (8%) / DPL (2%) / Dominion (59%) / JCPL (3%) / ME (2%) / PECO (5%) / PEPCO (10%) / PPL (3%) / PSEG / (5%)

Virginia Electric and Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0412	Retension Pruntytown – Mt. Storm 500 kV to a 3502 MVA rating		AEC (2.05%) / AEP (16.79%) / APS (5.96%) / BGE (4.91%) / ComEd (16.11%) / Dayton (2.53%) / DL (2.08%) / DPL (2.93%) / Dominion (13.22%) / JCPL (4.57%) / ME (2.04%) / NEPTUNE* (0.47%) / PECO (6.10%) / PENELEC (2.09%) / PEPCO (4.74%) / PPL (5.16%) / PSEG (7.58%) / RE (0.30%) / UGI (0.14%) / ECP** (0.23%)
b0450	Install 150 MVAR Capacitor at Fredricksburg 230 kV		
b0451	Install 25 MVAR Capacitor at Somerset 115 kV		
b0452	Install 150 MVAR Capacitor at Northwest 230 kV		
b0453.1	Convert Remingtion – Sowego 115 kV to 230 kV		
b0453.2	Add Sowego – Gainsville 230 kV		
b0453.3	Add Sowego 230/115 kV transformer		
b0454	Reconductor 2.4 miles of Newport News – Chuckatuck 230 kV		
b0455	Add 2nd Endless Caverns 230/115 kV transformer		
b0456	Reconductor 9.4 miles of Edinburg – Mt. Jackson 115 kV		
b0457	Replace both wave traps on Dooms – Lexington 500 kV		
b0467.2	Reconductor the Dickerson – Pleasant View 230 kV circuit		

*Neptune Regional Transmission System, LLC
**East Coast Power, L.L.C.

Virginia Electric and Power Company (cont.)

Required Transmission Enhancements Annual Revenue Requirement Responsible Customer(s)

b0512	MAPP Project – install new 500 kV transmission from Possum Point to Calvert Cliffs to Salem		AEC (2.05%) / AEP (16.79%) / APS (5.96%) / BGE (4.91%) / ComEd (16.11%) / Dayton (2.53%) / DL (2.08%) / DPL (2.93%) / Dominion (13.22%) / JCPL (4.57%) / ME (2.04%) / Neptune* (0.47%) / PECO (6.10%) / PENELEC (2.09%) / PEPCO (4.74%) / PPL (5.16%) / PSEG (7.58%) / RE (0.30%) / UGI (0.14%) / ECP** (0.23%)

*Neptune Regional Transmission System, LLC
**East Coast Power, L.L.C.

(21) Transmission Owners in the Midwest Independent System Operator, Inc.

Required Transmission Enhancements Annual Revenue Requirement Responsible Customer(s)

ATTACHMENT H-16
Annual Transmission Rates -- Virginia Electric and Power Company
for Network Integration Transmission Service

1. The Annual Transmission Revenue Requirement ("ATRR") and Rate for Network Integration Transmission Service are derived pursuant to the Formula Rate shown in Attachment H-16A, which is posted on the www.pjm.com website, and which reflects the cost of providing transmission service over 69 kV and higher transmission facilities of Virginia Electric and Power Company ("VEPCO"). The ATRR and Rate for Network Integration Transmission Service determined pursuant to Attachment H-16A shall be implemented pursuant to the Formula Rate Implementation Protocols set forth in Attachment H-16B. For Network Customer deliveries at voltages below 69 kV, additional charges for the lower voltage facilities shall be applied at rates as stated in the service agreements with such Network Customers.

2. On a monthly basis, the Transmission Provider shall calculate revenue credits based on the sum of VEPCO's share of revenues collected by it during the month from (i) the Long-Term Firm and Short-Term Firm Point-To-Point Transmission Service under Schedule 7; and (ii) the Network Integration Transmission Service to Non-Zone Network Load under Attachment H-A. Such credits shall be allocated to network and firm point-to-point customers serving load in the Dominion Zone based on demand charge ratios and will appear as reductions to these customers' bills for service in each month.

3. Within the Dominion Zone, a Network Customer's peak load and energy deliveries shall be adjusted to include transmission losses equal to 2.3387% of energy received for transmission. Additionally, for Network Customer deliveries at voltages below 69 kV, the Network Customer's peak load and energy deliveries shall also be adjusted to include distribution losses at rates as stated in the service agreements with such Network Customer. Notwithstanding section 15.7 of the Tariff, the transmission loss factor of 2.3387% also shall apply to point-to-point transmission service with a point of delivery in the Dominion Zone.

4. In addition to the rate set forth in section 1 above, the Network Customer purchasing Network Integration Transmission Service shall pay for transmission congestion charges, in accordance with the provisions of the Tariff, and any amounts necessary to reimburse the Transmission Owners for any amounts payable by them as sales, excise, "Btu," carbon, value-added or similar taxes (other than taxes based upon or measured by net income) with respect to the amounts payable pursuant to the Tariff.

5. Service under this Attachment H-16 shall also be subject to the terms of Attachment H-16C, Virginia Retail Administrative Fee Credit for Virginia Retail Load Serving Entities in the Dominion Zone.

Virginia Electric and Power Company
ATTACHMENT H-16A
Formula Rate -- Appendix A
Shaded cells are input cells

		Notes	FERC Form 1 Page # or Instruction (Note H)	(000's)
	Allocators			
	Wages & Salary Allocation Factor			
1	Transmission Wages Expense		p354.21b/ Attachment 5	$ -
2	Less Generator Step-ups		Attachment 5	-
3	Net Transmission Wage Expenses		(Line 1 - 2)	-
4	Total Wages Expense		p354.28b/Attachment 5	-
5	Less A&G Wages Expense		p354.27b/Attachment 5	-
6	Total		(Line 4 - 5)	$ -
7	**Wages & Salary Allocator**	(Note B)	(Line 3 / 6)	**#DIV/0!**
	Plant Allocation Factors			
8	Electric Plant in Service	(Notes A& Q)	p207.104.g/Attachment 5	#DIV/0!
9	Common Plant In Service - Electric		(Line 26)	#DIV/0!
10	Total Plant In Service		(Sum Lines 8 & 9)	#DIV/0!
11	Accumulated Depreciation (Total Electric Plant)	(Notes A & Q)	(Line 15 - 14 - 13 -12)	#DIV/0!
12	Accumulated Intangible Amortization	(Notes A & Q)	p200.21c/Attachment 5	#DIV/0!
13	Accumulated Common Amortization - Electric	(Notes A & Q)	p356/Attachment 5	#DIV/0!
14	Accumulated Common Plant Depreciation - Electric	(Notes A & Q)	p356/Attachment 5	#DIV/0!
15	Total Accumulated Depreciation		p219.29c/Attachment 5	#DIV/0!
16	Net Plant		(Line 10 - 15)	#DIV/0!
17	Transmission Gross Plant		(Line 31 - 30)	#DIV/0!
18	**Gross Plant Allocator**	(Note B)	(Line 17 / 10)	**#DIV/0!**
19	Transmission Net Plant		(Line 44 - 30)	#DIV/0!
20	**Net Plant Allocator**	(Note B)	(Line 19 / 16)	**#DIV/0!**
	Plant Calculations			
	Plant In Service			
21	Transmission Plant In Service	(Notes A,& Q)	p207.58.g/Attachment 5	#DIV/0!
22	Less: Generator Step-ups	(Notes A,& Q)	Attachment 5	#DIV/0!
23	Less: Interconnect Facilities Installed After March 15, 2000	(Notes A,& Q)	Attachment 5	#DIV/0!
24	**Total Transmission Plant In Service**		(Lines 21 - 22 - 23)	**#DIV/0!**
25	General & Intangible	(Notes A & Q)	p205.5.g + p207.99.g/Attachment 5	#DIV/0!
26	Common Plant (Electric Only)		p356/Attachment 5	#DIV/0!
27	Total General & Common		(Line 25 + 26)	#DIV/0!
28	Wage & Salary Allocation Factor		(Line 7)	#DIV/0!
29	**General & Common Plant Allocated to Transmission**		(Line 27 * 28)	**#DIV/0!**
30	**Plant Held for Future Use (Including Land)**	(Notes C & Q)	p214.47.d/Attachment 5	**$ -**
31	**TOTAL Plant In Service**		**(Line 24 + 29 + 30)**	**#DIV/0!**
	Accumulated Depreciation			
32	Transmission Accumulated Depreciation	(Notes A & Q)	p219.25.c/Attachment 5	#DIV/0!
33	Less Accumulated Depreciation for Generator Step-ups	(Notes A & Q)	Attachment 5	#DIV/0!
34	Less Accumulated Depreciation for Interconnect Facilities Installed After March 15, 2000	(Notes A & Q)	Attachment 5	#DIV/0!
35	Total Accumulated Depreciation for Transmission		(Line 32 - 33 - 34)	#DIV/0!
36	Accumulated General Depreciation	(Notes A & Q)	p219.28.b/Attachment 5	#DIV/0!
37	Accumulated Intangible Amortization	(Notes A & Q)	(Line 12)	#DIV/0!
38	Accumulated Common Amortization - Electric		(Line 13)	#DIV/0!
39	Common Plant Accumulated Depreciation (Electric Only)		(Line 14)	#DIV/0!
40	Total Accumulated Depreciation		(Sum Lines 36 to 39)	#DIV/0!
41	Wage & Salary Allocation Factor		(Line 7)	#DIV/0!
42	**General & Common Allocated to Transmission**		(Line 40 * 41)	**#DIV/0!**
43	**TOTAL Accumulated Depreciation**		**(Line 35 + 42)**	**#DIV/0!**
44	**TOTAL Net Property, Plant & Equipment**		**(Line 31 - 43)**	**#DIV/0!**

Adjustment To Rate Base

	Accumulated Deferred Income Taxes			
45	ADIT net of FASB 106 and 109		Attachment 1	#DIV/0!
46	**Accumulated Deferred Income Taxes Allocated To Transmission**		(Line 45)	**#DIV/0!**
	Transmission O&M Reserves			
47	**Total Balance Transmission Related Account 242 Reserves**	Enter Negative	Attachment 5	**#DIV/0!**
	Prepayments			
48	Prepayments	(Notes A & R)	Attachment 5	#DIV/0!
49	**Total Prepayments Allocated to Transmission**		(Line 48)	**#DIV/0!**
	Materials and Supplies			
50	Undistributed Stores Exp	(Notes A & R)	p227.6c & 16.c	$ -
51	Wage & Salary Allocation Factor		(Line 7)	#DIV/0!
52	Total Transmission Allocated Materials and Supplies		(Line 50 * 51)	#DIV/0!
53	Transmission Materials & Supplies		p227.8c/2	3,078
54	**Total Materials & Supplies Allocated to Transmission**		(Line 52 + 53)	**#DIV/0!**
	Cash Working Capital			
55	Transmission Operation & Maintenance Expense		(Line 85)	#DIV/0!
56	1/8th Rule		x 1/8	12.5%
57	**Total Cash Working Capital Allocated to Transmission**		(Line 55 * 56)	**#DIV/0!**
	Network Credits			
58	Outstanding Network Credits	(Note N)	Attachment 5 / From PJM	0
59	Less Accumulated Depreciation Associated with Facilities with Outstanding Network Credits	(Note N)	Attachment 5 / From PJM	0
60	Net Outstanding Credits		(Line 58 - 59)	**0**
61	**TOTAL Adjustment to Rate Base**		(Line 46 + 47 + 49 + 54 + 57 - 60)	**#DIV/0!**
62	**Rate Base**		(Line 44 + 61)	**#DIV/0!**

O&M

	Transmission O&M			
63	Transmission O&M		p321.112.b/Attachment 5	$ -
64	Less GSU Maintenance		Attachment 5	216
65	Less Account 565 - Transmission by Others		p321.96.b/Attachment 5	0
66	Plus Schedule 12 Charges billed to Transmission Owner and booked to Account 565	(Note O)	PJM Data	
67	**Transmission O&M**		(Lines 63 - 64 + 65 + 66)	**$ (216)**
	Allocated General & Common Expenses			
68	Common Plant O&M	(Note A)	p356	
69	Total A&G		Attachment 5	0
70	Less Property Insurance Account 924		p323.185b	
71	Less Regulatory Commission Exp Account 928	(Note E)	p323.189b/Attachment 5	24,106
72	Less General Advertising Exp Account 930.1		p323.911b/Attachment 5	2,629
73	Less EPRI Dues	(Note D)	p352-353/Attachment 5	0
74	**General & Common Expenses**		(Lines 68 + 69) - Sum (70 to 73)	$ (26,735)
75	Wage & Salary Allocation Factor		(Line 7)	#DIV/0!
76	**General & Common Expenses Allocated to Transmission**		(Line 74 * 75)	**#DIV/0!**
	Directly Assigned A&G			
77	Regulatory Commission Exp Account 928	(Note G)	p323.189b/Attachment 5	$ -
78	General Advertising Exp Account 930.1	(Note K)	p323.191b	0
79	Subtotal - Transmission Related		(Line 77 + 78)	**0**
80	Property Insurance Account 924		p323.185b	
81	General Advertising Exp Account 930.1	(Note F)	Attachment 5	0
82	Total		(Line 80 + 81)	7,982
83	Net Plant Allocation Factor		(Line 20)	#DIV/0!
84	**A&G Directly Assigned to Transmission**		(Line 82 * 83)	**#DIV/0!**
85	**Total Transmission O&M**		**(Line 67 + 76 + 79 + 84)**	**#DIV/0!**

Depreciation & Amortization Expense

Line	Description	Note	Source	Amount
	Depreciation Expense			
86	Transmission Depreciation Expense	(Notes A and S)	p336.7b&c/Attachment 5	$ -
87	Less: GSU Depreciation		Attachment 5	**0**
88	Less Interconnect Facilities Depreciation		Attachment 5	**0**
89	Extraordinary Property Loss		Attachment 5	**#DIV/0!**
90	Total Transmission Depreciation		(Line 86 - 87 - 88 + 89)	**#DIV/0!**
91	General Depreciation	(Note A)	p336.10b&c&d/Attachment 5	0
92	Intangible Amortization	(Note A)	p336.1d&e/Attachment 5	0
93	Total		(Line 91 + 92)	**0**
94	Wage & Salary Allocation Factor		(Line 7)	#DIV/0!
95	**General and Intangible Depreciation Allocated to Transmission**		(Line 93 * 94)	**#DIV/0!**
96	Common Depreciation - Electric Only	(Note A)	p336.11.b	0
97	Common Amortization - Electric Only	(Note A)	p356 or p336.11d	0
98	Total		(Line 96 + 97)	0
99	Wage & Salary Allocation Factor		(Line 7)	#DIV/0!
100	**Common Depreciation - Electric Only Allocated to Transmission**		(Line 98 * 99)	**#DIV/0!**
101	**Total Transmission Depreciation & Amortization**		**(Line 90 + 95 + 100)**	**#DIV/0!**

Taxes Other than Income

Line	Description	Note	Source	Amount
102	**Taxes Other than Income**		Attachment 2	**#DIV/0!**
103	**Total Taxes Other than Income**		**(Line 102)**	**#DIV/0!**

Return / Capitalization Calculations

Line	Description		Note	Source	Amount
	Long Term Interest				
104	Long Term Interest			p117.62c through 67c	
105	Less LTD Interest on Securitization Bonds		(Note P)	Attachment 8	0
106	**Long Term Interest**			(Line 104 - 105)	$ -
107	**Preferred Dividends**		enter positive	p118.29c	
	Common Stock				
108	Proprietary Capital			p112.16c,d/2	
109	Less Preferred Stock		enter negative	(Line 117)	
110	Less Account 219 - Accumulated Other Comprehensive Income		enter negative	p112.15c,d/2	
111	**Common Stock**			(Sum Lines 108 to 110)	$ -
	Capitalization				
112	Long Term Debt			p112.24c,d/2	
113	Less Loss on Reacquired Debt		enter negative	p111.81c,d/2	
114	Plus Gain on Reacquired Debt		enter positive	p113.61c,d/2	
115	Less LTD on Securitization Bonds	(Note P)	enter negative	Attachment 8	0
116	Total Long Term Debt			(Sum Lines 112 to 115)	0
117	Preferred Stock			p112.3c,d/2	
118	Common Stock			(Line 111)	0
119	**Total Capitalization**			(Sum Lines 116 to 118)	$ -
120	Debt %	Total Long Term Debt		(Line 116 / 119)	0.0%
121	Preferred %	Preferred Stock		(Line 117 / 119)	0.0%
122	Common %	Common Stock		(Line 118 / 119)	0.0%
123	Debt Cost	Total Long Term Debt		(Line 106 / 116)	0.0000
124	Preferred Cost	Preferred Stock		(Line 107 / 117)	0.0000
125	Common Cost	Common Stock	(Note J)	Fixed	
126	Weighted Cost of Debt	Total Long Term Debt (WCLTD)		(Line 120 * 123)	0.0000
127	Weighted Cost of Preferred	Preferred Stock		(Line 121 * 124)	0.0000
128	Weighted Cost of Common	Common Stock		(Line 122 * 125)	0.0000
129	**Total Return (R)**			(Sum Lines 126 to 128)	**0.0000**
130	**Investment Return = Rate Base * Rate of Return**			**(Line 62 * 129)**	**#DIV/0!**

Composite Income Taxes

	Income Tax Rates				
131	FIT=Federal Income Tax Rate			Attachment 5	
132	SIT=State Income Tax Rate or Composite		(Note I)	Attachment 5	0.00%
133	p	(percent of federal income tax deductible for state purposes)		Per State Tax Code	0.00%
134	T	T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =			0.00%
135	T/ (1-T)				0.00%
	ITC Adjustment		(Note I)		
136	Amortized Investment Tax Credit		enter negative	Attachment 1	$ -
137	T/(1-T)			(Line 135)	0.00%
138	**ITC Adjustment Allocated to Transmission**			(Line 136 * (1 + 137))	**$ -**
139	**Income Tax Component =**	CIT=(T/1-T) * Investment Return * (1-(WCLTD/R)) =		[Line 135 * 130 * (1-(126 / 129))]	**#DIV/0!**
140	**Total Income Taxes**			**(Line 138 + 139)**	**#DIV/0!**

REVENUE REQUIREMENT

	Summary		
141	Net Property, Plant & Equipment	(Line 44)	#DIV/0!
142	Adjustment to Rate Base	(Line 61)	#DIV/0!
143	**Rate Base**	(Line 62)	**#DIV/0!**
144	O&M	(Line 85)	#DIV/0!
145	Depreciation & Amortization	(Line 101)	#DIV/0!
146	Taxes Other than Income	(Line 103)	#DIV/0!
147	Investment Return	(Line 130)	#DIV/0!
148	Income Taxes	(Line 140)	#DIV/0!
149			
150	**Revenue Requirement**	**(Sum Lines 144 to 149)**	**#DIV/0!**
	Net Plant Carrying Charge		
151	Revenue Requirement	(Line 150)	**#DIV/0!**
152	Net Transmission Plant	(Line 24 - 35)	**#DIV/0!**
153	Net Plant Carrying Charge	(Line 151 / 152)	**#DIV/0!**
154	Net Plant Carrying Charge without Depreciation	(Line 151 - 86) / 152	**#DIV/0!**
155	Net Plant Carrying Charge without Depreciation, Return or Income Taxes	(Line 151 - 86 - 130 - 140) / 152	**#DIV/0!**
	Net Plant Carrying Charge Calculation per 100 Basis Point increase in ROE		
156	Gross Revenue Requirement Less Return and Taxes	(Line 150 - 147 - 148)	**#DIV/0!**
157	Increased Return and Taxes	Attachment 4	**#DIV/0!**
158	Net Revenue Requirement per 100 Basis Point increase in ROE	(Line 156 + 157)	**#DIV/0!**
159	Net Transmission Plant	(Line 152)	**#DIV/0!**
160	Net Plant Carrying Charge per 100 Basis Point increase in ROE	(Line 158 / 159)	**#DIV/0!**
161	Net Plant Carrying Charge per 100 Basis Point increase in ROE without Depreciation	(Line 158 - 86) / 159	**#DIV/0!**
162	**Revenue Requirement**	(Line 150)	**#DIV/0!**
163	True-Up Adjustment	Attachment 6	**-**
164	Plus any increased ROE calculated on Attachment 7 other than PJM Schedule 12 projects.	Attachment 7	**-**
165	Facility Credits under Section 30.9 of the PJM OATT.	Attachment 5	**-**
166	Revenue Credits	Attachment 3	**-**
167	Interest on Network Credits	PJM data	
168	**Annual Transmission Revenue Requirement (ATRR)**	(Line 162 + 163 +164 + 165 + 166 + 167)	**#DIV/0!**
	Rate for Network Integration Transmission Service		
169	1 CP Peak (Note L)	PJM Data	
170	Rate ($/MW-Year)	(Line 168 / 169)	**#DIV/0!**
171	**Rate for Network Integration Transmisson Service Rate ($/MW/Year)**	**(Line 170)**	**#DIV/0!**

Notes

A Electric portion only - VEPCO does not have Common Plant.
B Excludes amounts for Generator Step-ups and Interconnection Facilities, when appropriate.
C Includes Transmission portion only.
D Excludes all EPRI Annual Membership Dues.
E Includes all regulatory commission expenses.
F Includes all safety related advertising included in Account 930.1.
G Includes all regulatory commission expenses directly related to transmission service, RTO filings, or transmission siting itemized in Form 1 at 351.h.
H The Form 1 reference incates only the end-of-year balance used to derive the amount beside the reference. Each plant balance with a Form 1 reference will include the Form 1 balance in an average of the 13 month blances for the year. Each non-plant balance included in rate base with a Form 1 reference will include Form 1 balances in the calculation of the average of the beginning and end of year balances for the year. See notes Q and R below.
I 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 includes taxes in more than one state, it must explain in Attachment 5 the name of each state and how the blended or composite SIT was developed. Furthermore, a utility that elected to use 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). A utility must not include tax credits as a reduction to rate base and as an amortization against taxable income.
J ROE will be supported in the original filing and no change in ROE will be made absent a filing at FERC. The basis point increase in ROE for new investment will be set at 100 basis points in Attachment 4 but not applied to determine any of the charges resulting from this formula absent absent a filing at FERC.
K Education and outreach expenses relating to transmission, for example siting or billing.
L As provided for in Section 34.1 of the PJM OATT.
M Amount of transmission plant excluded from rates per Attachment 5.
N Outstanding Network Credits is the balance of Network Facilities Upgrades Credits due Transmission Customers who have made lump-sum payments (net of accumulated depreciation) toward the construction of Network Transmission Facilities consistent with Paragraph 657 of Order 2003-A. Interest on the Network Credits as booked each year is added to the revenue requirement on Line 167.
O Payments made under Schedule 12 of the PJM OATT that are not directly assessed to load in the Zone under Schedule 12 are included in Transmission O&M. If they are booked to Acct 565, they are included on Line 66.
P Securitization bonds may be included in the capital structure.
Q Calculated using 13 month average balance. Only beginning and end of year balances are from Form 1.
R Calculated using average of beginning and end of year balances. Beginning and end of year balances are from Form 1.
S The depreciation rates are included in Attachment 9.

END

Virginia Electric and Power Company
ATTACHMENT H-16A
Attachment 1 - Accumulated Deferred Income Taxes (ADIT) Worksheet - December 31,200_

	Only Transmission Related	Plant Related	Labor Related	Total ADIT
ADIT- 282	0	0	0	
ADIT-283	0	0	0	
ADIT-190	0	0	0	
Subtotal	0	0	0	
Wages & Salary Allocator			#DIV/0!	
Gross Plant Allocator		#DIV/0!		
End of Year ADIT	0	#DIV/0!	#DIV/0!	#DIV/0!
End of Previous Year ADIT (from Sheet 1A-ADIT (3))	0	#DIV/0!	#DIV/0!	#DIV/0!
Average Beginning and End of Year ADIT	0	#DIV/0!	#DIV/0!	#DIV/0!

End of Year ADIT	#DIV/0!
End of Previous Year ADIT	#DIV/0!
Average Beginning and End of Year ADIT	#DIV/0!

In filling out this attachment, a full and complete description of each item and justification for the allocation to Columns B-E and each separate ADIT item will be listed. Dissimilar items with amounts exceeding $100,000 will be listed separately.

End of Year Balances :

A *ADIT-190*	B *Total*	C *Production Or Other Related*	D *Only Transmission Related*	E *Plant Related*	F *Labor Related*	G *Justification*
	-					
	-					
	-					
	-					
	-					
	-					
	-					
	-					
	-					
	-					
	-					
	-					
	-					
	-					
	-					
	-					
	-					
	-					
	-					
	-					
	-					
	-					
	-					
	-					
	-					
	-					
	-					
	-					
	-					
	-					
	-					
Subtotal - p234	0	0	0	0	0	
Less FASB 109 Above if not separately removed						
Less FASB 106 Above if not separately removed						
Total	0	0	0	0	0	

Instructions for Account 190:

1. ADIT items related only to Non-Electric Operations (e.g., Gas, Water, Sewer) or Production are directly assigned to Column C
2. ADIT items related only to Transmission are directly assigned to Column D
3. ADIT items related to Plant and not in Columns C & D are included in Column E
4. ADIT items related to labor and not in Columns C & D are included in Column F

5. Deferred income taxes arise when items are included in taxable income in different periods than they are included in rates, therefore if the item giving rise to the ADIT is not included in the formula, the associated ADIT amount shall be excluded

6. Re: Form 1-F filer: Sum of subtotals for Accounts 282 and 283 should tie to Form No. 1-F, p.113.57.c

Virginia Electric and Power Company
ATTACHMENT H-16A
Attachment 1 - Accumulated Deferred Income Taxes (ADIT) Worksheet - December 31,200_

	Only Transmission Related	Plant Related	Labor Related	Total ADIT
ADIT- 282	0	0	0	
ADIT-283	0	0	0	
ADIT-190	0	0	0	
Subtotal	0	0	0	
Wages & Salary Allocator			0.0000%	
Gross Plant Allocator		0.0000%		
End of Year ADIT	0	0	0	0
End of Previous Year ADIT (from Sheet 1A-ADIT (3))	0	0	0	0
Average Beginning and End of Year ADIT	0	0	0	0

End of Year ADIT	0
End of Previous Year ADIT	0
Average Beginning and End of Year ADIT	0

In filling out this attachment, a full and complete description of each item and justification for the allocation to Columns B-E and each separate ADIT item will be listed. Dissimilar items with amounts exceeding $100,000 will be listed separately.

End of Year Balances :

A ADIT- 282	B Total	C Production Or Other Related	D Only Transmission Related	E Plant Related	F Labor Related	G Justification
	-					
	-					
	-					
	-					
	-					
	-					
	-					
	-					
	-					
	-					
	-					
	-					
	-					
	-					
	-					
	-					
	-					
	-					
	-					
	-					
	-					
	-					
	-					
Subtotal - p275 (Form 1-F filer: see note 6 below)	0	0	0	0	0	
Less FASB 109 Above if not separately removed	0					
Less FASB 106 Above if not separately removed	0					
Total	0	0	0	0	0	

Instructions for Account 282:
1. ADIT items related only to Non-Electric Operations (e.g., Gas, Water, Sewer) or Production are directly assigned to Column C
2. ADIT items related only to Transmission are directly assigned to Column D
3. ADIT items related to Plant and not in Columns C & D are included in Column E
4. ADIT items related to labor and not in Columns C & D are included in Column F
5. Deferred income taxes arise when items are included in taxable income in different periods than they are included in rates, therefore if

6. Re: Form 1-F filer: Sum of subtotals for Accounts 282 and 283 should tie to Form No. 1-F, p.113.57.c

Virginia Electric and Power Company
ATTACHMENT H-16A
*Attachment 1 - Accumulated Deferred Income Taxes (ADIT) Worksheet - December 31,200_*

	Only Transmission Related	Plant Related	Labor Related	Total ADIT
ADIT- 282	0	0	0	
ADIT-283	0	0	0	
ADIT-190	0	0	0	
Subtotal	0	0	0	
Wages & Salary Allocator			0.0000%	
Gross Plant Allocator		0.0000%		
End of Year ADIT	0	0	0	0
End of Previous Year ADIT (from Sheet 1A-ADIT (3))	0	0	0	0
Average Beginning and End of Year ADIT	0	0	0	0

End of Year ADIT	0
End of Previous Year ADIT	0
Average Beginning and End of Year ADIT	0

In filling out this attachment, a full and complete description of each item and justification for the allocation to Columns B-E and each separate ADIT item will be listed. Dissimilar items with amounts exceeding $100,000 will be listed separately.

End of Year Balances :

A ADIT-283	B Total	C Production Or Other Related	D Only Transmission Related	E Plant Related	F Labor Related	G Justification
	-					
	-					
	-					
	-					
	-					
	-					
	-					
	-					
	-					
	-					
	-					
	-					
	-					
	-					
	-					
	0					
Subtotal - p277 (Form 1-F filer: see note 6, below)	0	-	-	-	-	
Less FASB 109 Above if not separately removed	-					
Less FASB 106 Above if not separately removed	-				-	
Total	-	-	-	-	-	

Instructions for Account 283:
1. ADIT items related only to Non-Electric Operations (e.g., Gas, Water, Sewer) or Production are directly assigned to Column C
2. ADIT items related only to Transmission are directly assigned to Column D
3. ADIT items related to Plant and not in Columns C & D are included in Column E
4. ADIT items related to labor and not in Columns C & D are included in Column F
5. Deferred income taxes arise when items are included in taxable income in different periods than they are included in rates, therefore if

6. Re: Form 1-F filer: Sum of subtotals for Accounts 282 and 283 should tie to Form No. 1-F, p.113.57.c

Attachment 1- Accumulated Deferred Income Taxes (ADIT) Worksheet

Amortization ITC-255

		Item	Balance	Amortization
1	Amortization			-
2	Amortization to line 136 of Appendix A	Total		
3	Total		-	-
4	Total Form No. 1 (p 266 & 267)	Form No. 1 balance (p.266) for amortization		
5	Difference /1		-	-

/1 Difference must be zero

Virginia Electric and Power Company
ATTACHMENT H-16A
Attachment 1A - Accumulated Deferred Income Taxes (ADIT) Worksheet - December 31 of the Previous Year

	Only Transmission Related	*Plant Related*	*Labor Related*	*Total ADIT*
ADIT- 282	0	0	0	
ADIT-283	0	0	0	
ADIT-190	0	0	0	
Subtotal	0	0	0	
Wages & Salary Allocator			#DIV/0!	
Gross Plant Allocator		#DIV/0!		
ADIT	0	#DIV/0!	#DIV/0!	#DIV/0!

In filling out this attachment, a full and complete description of each item and justification for the allocation to Columns B-E and each separate ADIT item will be listed. Dissimilar items with amounts exceeding $100,000 will be listed separately.

A *ADIT-190*		B *Total*	C *Production Or Other Related*	D *Only Transmission Related*	E *Plant Related*	F *Labor Related*	G *Justification*
		-					
		-					
		-					
		-					
		-					
		-					
		-					
		-					
		-					
		-					
		-					
		-					
		-					
		-					
		-					
		-					
		-					
		-					
		-					
		-					
Subtotal - p234		0	0	0	0	0	
Less FASB 109 Above if not separately removed		0					
Less FASB 106 Above if not separately removed		0					
Total		0	0	0	0	0	

Instructions for Account 190:

1. ADIT items related only to Non-Electric Operations (e.g., Gas, Water, Sewer) or Production are directly assigned to Column C
2. ADIT items related only to Transmission are directly assigned to Column D
3. ADIT items related to Plant and not in Columns C & D are included in Column E
4. ADIT items related to labor and not in Columns C & D are included in Column F
5. Deferred income taxes arise when items are included in taxable income in different periods than they are included in rates, therefore if the item giving rise to the ADIT is not included in the formula, the associated ADIT amount shall be excluded

6. Re: Form 1-F filer: Sum of subtotals for Accounts 282 and 283 should tie to Form No. 1-F, p.113.57.c

A *ADIT- 282*		B *Total*	C *Production Or Other Related*	D *Only Transmission Related*	E *Plant Related*	F *Labor Related*	G *Justification*
		-					
		-					
		-					
		-					
		-					
		-					
		-					
		-					
		-					
		-					
		-					
		-					
		-					
		-					
		-					
		-					
		-					
		-					
		-					
Subtotal - p275 (Form 1-F filer: see note 6 below)		0	0	0	0	0	
Less FASB 109 Above if not separately removed							
Less FASB 106 Above if not separately removed							
Total		0	0	0	0	0	

Instructions for Account 282:
1. ADIT items related only to Non-Electric Operations (e.g., Gas, Water, Sewer) or Production are directly assigned to Column C
2. ADIT items related only to Transmission are directly assigned to Column D
3. ADIT items related to Plant and not in Columns C & D are included in Column E
4. ADIT items related to labor and not in Columns C & D are included in Column F
5. Deferred income taxes arise when items are included in taxable income in different periods than they are included in rates, therefore if the item giving rise to the ADIT is not included in the formula, the associated ADIT amount shall be excluded

6. Re: Form 1-F filer: Sum of subtotals for Accounts 282 and 283 should tie to Form No. 1-F, p.113.57.c

Virginia Electric and Power Company
ATTACHMENT H-16A
Attachment 1A - Accumulated Deferred Income Taxes (ADIT) Worksheet - December 31 of the Previous Year

	Only Transmission Related	Plant Related	Labor Related	Total ADIT
ADIT- 282	0	0	0	
ADIT-283	0	0	0	
ADIT-190	0	0	0	
Subtotal	0	0	0	
Wages & Salary Allocator			0.0000%	
Gross Plant Allocator		#DIV/0!		
ADIT	0	#DIV/0!	0	#DIV/0!

In filling out this attachment, a full and complete description of each item and justification for the allocation to Columns B-E and each separate ADIT item will be listed. Dissimilar items with amounts exceeding $100,000 will be listed separately.

A ADIT-283		B Total	C Production Or Other Related	D Only Transmission Related	E Plant Related	F Labor Related	G Justification
		-					
		-					
		-					
		-					
		-					
		-					
		-					
		-					
		-					
		-					
		-					
		-					
		-					
		-					
		0					
Subtotal - p277 (Form 1-F filer: see note 6, below)		0	-	-	-	-	
Less FASB 109 Above if not separately removed							
Less FASB 106 Above if not separately removed						-	
Total		-	-	-	-	-	

Instructions for Account 283:
1. ADIT items related only to Non-Electric Operations (e.g., Gas, Water, Sewer) or Production are directly assigned to Column C
2. ADIT items related only to Transmission are directly assigned to Column D
3. ADIT items related to Plant and not in Columns C & D are included in Column E
4. ADIT items related to labor and not in Columns C & D are included in Column F
5. Deferred income taxes arise when items are included in taxable income in different periods than they are included in rates, therefore i

6. Re: Form 1-F filer: Sum of subtotals for Accounts 282 and 283 should tie to Form No. 1-F, p.113.57.c

Attachment 1- Accumulated Deferred Income Taxes (ADIT) Worksheet

Virginia Electric and Power Company
ATTACHMENT H-16A
Attachment 2 - Taxes Other Than Income Worksheet
(000's)

	Other Taxes	*Page 263 Col (i)*	*Allocator*	*Allocated Amount*	
	Plant Related		***Gross Plant Allocator***		
1	Transmission Personal Property Tax (directly assigned to Transmission)	#DIV/0!	100.0000%	#DIV/0!	
1a	Other Plant Related Taxes	0	#DIV/0!	#DIV/0!	
2					-
3					-
4					-
5					-
					-
	Total Plant Related	#DIV/0!			#DIV/0!
	Labor Related		***Wages & Salary Allocator***		
6	Federal FICA & Unemployment & State Unemployment				
	Total Labor Related	$ -	#DIV/0!		#DIV/0!
	Other Included		***Gross Plant Allocator***		
7	Sales and Use Tax				
	Total Other Included	$ -	#DIV/0!		#DIV/0!
	Total Included				#DIV/0!
	Currently Excluded				
8	Business and Occupation Tax - West Virginia				
9	Gross Receipts Tax				
10	IFTA Fuel Tax				
11	Property Taxes - Other	#DIV/0!			
12					
13					
14					
15					
16					
17					
18					
19					
20					
21	Total "Other" Taxes (included on p. 263)	#DIV/0!			
22	Total "Taxes Other Than Income Taxes" - acct 408.10 (p. 114.14)	#DIV/0!			
23	Difference	#DIV/0!			

Criteria for Allocation:
A Other taxes that are incurred through ownership of plant including transmission plant will be either directly assigned or allocated based on the Gross Plant Allocator. If the taxes are 100% recovered at retail they will not be included.
B Other taxes that are incurred through ownership of only general or intangible plant will be allocated based on the Wages and Salary Allocator. If the taxes are 100% recovered at retail they will not be included.
C Other taxes that are assessed based on labor will be allocated based on the Wages and Salary Allocator.
D Other taxes except as provided for in A, B and C above, that are incurred and (1) are not fully recovered at retail or (2) are directly or indirectly related to transmission service will be allocated based on the Gross Plant Allocator; provided, however, that overheads shall be treated as in footnote B above.

VEPCO
ATTACHMENT H-16A
Attachment 2A - Direct Assignment of Property Taxes Per Function
(000's)

Directly Assigned Property Taxes	
Production Property Tax	
Transmission Property Tax	
Distribution Property tax	
General Property Tax	
Total check	-

Allocation of General Property Tax to Transmission	
General Property Tax	$ -
Wages & Salary Allocator	#DIV/0!
Trans General	#DIV/0!

Total Transmission Property Taxes	
Transmission	$ -
General	#DIV/0!
Total Transmission Property Taxes	#DIV/0!

Virginia Electric and Power Company
ATTACHMENT H-16A
Attachment 3 - Revenue Credit Workpaper
(000's)

Line	Description		Transmission Related	Production/Other Related	Total
	Account 454 - Rent from Electric Property				
1	Rent from Electric Property - Transmission Related (Note 3)			-	-
2	Total Rent Revenues	(Sum Lines 1)	-	-	-
	Account 456 - Other Electric Revenues (Note 1)				
3	Schedule 1A				
4	Net revenues associated with Network Integration Transmission Service (NITS) and for the transmission component of the NCEMPA contract rate for which the load is not included in the divisor. (Note 4)				-
5	Point to Point Service revenues received by Transmission Owner for which the load is not included in the divisor (Note 4)				-
6	PJM Transitional Revenue Neutrality (Note 1)				-
7	PJM Transitional Market Expansion (Note 1)				-
8	Professional Services (Note 3)				-
9	Revenues from Directly Assigned Transmission Facility Charges (Note 2)				-
10	Rent or Attachment Fees associated with Transmission Facilities (Note 3)				-
11	Gross Revenue Credits	(Sum Lines 2-10)	-	-	-
12	Less line 14g		-	-	-
13	Total Revenue Credits		-	-	-
	Revenue Adjustment to Determine Revenue Credit				
14a	Revenues included in lines 1-11 which are subject to 50/50 sharing. (Lines 1 + 8 + 10)		-	-	-
14b	Costs associated with revenues in line 14a			-	-
14c	Net Revenues (14a - 14b)		-	-	-
14d	50% Share of Net Revenues (14c / 2)		-	-	-
14e	Cost associated with revenues in line 14b that are included in FERC accounts recovered through the formula times the allocator used to functionalize the amounts in the FERC account to the transmission service at issue		-	-	-
14f	Net Revenue Credit (14d + 14e)		-	-	-
14g	Line 14f less line 14a		-	-	-
16	Amount offset in line 4 above (Note 4)		-	-	-
17	Total Amounts in Accounts 454 and 456		-	-	-

<u>Revenue Adjustment to Determine Revenue Credit</u>

Note 1: All revenues related to transmission that are received as a transmission owner (*i.e.*, not received as a LSE), for which the cost of the service is recovered under this formula, except as specifically provided for elsewhere in this Attachment or elsewhere in the formula will be included as a revenue credit or included in the peak on line 169 of Appendix A.

Note 2: If the costs associated with the Directly Assigned Transmission Facility Charges are included in the Rates, the associated revenues are included in the Rates. If the costs associated with the Directly Assigned Transmission Facility Charges are not included in the Rates, the associated revenues are not included in the Rates.

Note 3: Ratemaking treatment for the following specified secondary uses of transmission assets: (1) right-of-way leases and leases for space on transmission facilities for telecommunications; (2) transmission tower licenses for wireless antennas; (3) right-of-way property leases for farming, grazing or nurseries; (4) licenses of intellectual property (including a portable oil degasification process and scheduling software); and (5) transmission maintenance and consulting services (including energized circuit maintenance, high-voltage substation maintenance, safety training, transformer oil testing, and circuit breaker testing) to other utilities and large customers (collectively, products). VEPCO will retain 50% of net revenues consistent with *Pacific Gas and Electric Company*, 90 FERC ¶ 61,314. In order to use lines 14a - 14g, the utility must track in separate subaccounts the revenues and costs associated with each secondary use (except for the cost of the associated income taxes).

Note 4: Revenues from Schedule 12 are not included in the total above to the extent they are credited under Schedule 12. In addition, revenues from Schedule 7, Schedule 8 and H-A are not included in the total above to the extent PJM credits VEPCO's share of these revenues monthly to network customers under Attachment H-16.

Virginia Electric and Power Company
ATTACHMENT H-16A
Attachment 4 - Calculation of 100 Basis Point Increase in ROE
(000's)

	Return and Taxes with Basis Point increase in ROE				
A	Basis Point increase in ROE and Income Taxes			(Line 130 + 140)	#DIV/0!
B	100 Basis Point increase in ROE	(Note J from Appendix A)		Fixed	1.00%
Return Calculation					
Line Ref.					
62	Rate Base			(Line 44 + 61)	#DIV/0!
	Long Term Interest				
104	**Long Term Interest**			p117.62c through 67c	0
105	Less LTD Interest on Securitization Bonds	(Note P)		Attachment 8	0
106	Long Term Interest			(Line 104 - 105)	0
107	Preferred Dividends		enter positive	p118.29c	0
	Common Stock				
108	Proprietary Capital			p112.16c,d/2	0
109	Less Preferred Stock		enter negative	(Line 117)	0
110	Less Account 219 - Accumulated Other Comprehensive Income		enter negative	p112.15c,d/2	0
111	Common Stock			(Sum Lines 108 to 110)	0
	Capitalization				
112	Long Term Debt			p112.24c,d/2	0
113	Less Loss on Reacquired Debt		enter negative	p111.81c,d/2	0
114	Plus Gain on Reacquired Debt		enter positive	p113.61c,d/2	0
115	Less LTD on Securitization Bonds		enter negative	Attachment 8	0
116	Total Long Term Debt			(Sum Lines 112 to 115)	0
117	Preferred Stock			p112.3c,d/2	0
118	Common Stock			(Line 111)	0
119	Total Capitalization			(Sum Lines 116 to 118)	0
120	Debt %		Total Long Term Debt	(Line 116 / 119)	0.0%
121	Preferred %		Preferred Stock	(Line 117 / 119)	0.0%
122	Common %		Common Stock	(Line 118 / 119)	0.0%
123	Debt Cost		Total Long Term Debt	(Line 106 / 116)	0.0000
124	Preferred Cost		Preferred Stock	(Line 107 / 117)	0.0000
125	Common Cost	(Note J from Appendix A)	Common Stock	Fixed	0.0100
126	Weighted Cost of Debt		Total Long Term Debt (WCLTD)	(Line 120 * 123)	0.0000
127	Weighted Cost of Preferred		Preferred Stock	(Line 121 * 124)	0.0000
128	Weighted Cost of Common		Common Stock	(Line 122 * 125)	0.0000
129	Total Return (R)			**(Sum Lines 126 to 128)**	**0.0000**
130	Investment Return = Rate Base * Rate of Return			**(Line 62 * 129)**	**#DIV/0!**
Composite Income Taxes					
	Income Tax Rates				
131	FIT=Federal Income Tax Rate				0.0000
132	SIT=State Income Tax Rate or Composite				0.0000
133	p = percent of federal income tax deductible for state purposes			Per State Tax Code	0.0000
134	T	T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =			0.0000
135	T/ (1-T)				0.0000
	ITC Adjustment				
136	Amortized Investment Tax Credit		enter negative	Attachment 1	0
137	T/(1-T)			(Line 135)	0.0000
138	**ITC Adjustment Allocated to Transmission**		(Note I from Appendix A)	(Line 136 * (1 + 137))	**0**
139	**Income Tax Component =**	CIT=(T/1-T) * Investment Return * (1-(WCLTD/R)) =			#DIV/0!
140	**Total Income Taxes**			**(Line 138 + 139)**	**#DIV/0!**

Virginia Electric and Power Company
ATTACHMENT H-16A
Attachment 5 - Cost Support

2008 - Projected

Electric / Non-electric Cost Support

Line #s	Descriptions	Notes	Page #'s & Instructions	Previous Year Form 1Dec	Current Year Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Form 1 Dec	Average	Non-electric Portion	Details
	Plant Allocation Factors																		
8	Electric Plant in Service	(Notes A & Q)	p207.104g/Plant-Acc. Deprc Wkst														#DIV/0!	0	
15	Accumulated Depreciation (Total Electric Plant)	(Notes A & Q)	p219.29c														#DIV/0!	0	
12	Accumulated Intangible Amortization	(Notes A & Q)	p200.21c														#DIV/0!	0	Respondent is Electric Utility only.
13	Accumulated Common Amortization - Electric	(Notes A & Q)	p356														#DIV/0!	0	
14	Accumulated Common Plant Depreciation - Electric	(Notes A & Q)	p356														#DIV/0!	0	
	Plant In Service																		
21	Transmission Plant in Service	(Notes A,& Q)	p207.58.g/Trans.Input Sht														#DIV/0!	0	
15	Generator Step-Ups		Trans. Input Sht														#DIV/0!	0	
23	Generator Interconnect Facilities		Input Sht														#DIV/0!		
25	General & Intangible		p205.5.g & p207.99.g/G&I Wksht														#DIV/0!	0	
26	Common Plant (Electric Only)	(Notes A & Q)	p356														#DIV/0!	0	
	Accumulated Depreciation																		
32	Transmission Accumulated Depreciation	(Notes A & Q)	p219.25.c/Trans.Input Sht														#DIV/0!	0	
33	Transmission Accumulated Depreciation - Generator Step-Ups		GSU Input Sht														#DIV/0!	0	
34	Transmission Accumulated Depreciation - Interconnection Facilities		Input Sht														#DIV/0!		
36	Accumulated General Depreciation	(Notes A & Q)	p219.28.b														#DIV/0!	0	
	Materials and Supplies																		
50	Undistributed Stores Exp	(Notes A & R)	p227.6c & 16.c														#DIV/0!	0	Respondent is Electric Utility only.
	Allocated General & Common Expenses																		
68	Common Plant O&M	(Note A)	p356	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0	
	Depreciation Expense																Electric		
86	Depreciation-Transmission	(Note A)	p336.7.b&c																
91	Depreciation-General	(Note A)																	
92	Depreciation-Intangible	(Note A)	p336.1d&e/Attachment 5																Respondent is Electric Utility only.
87	Depreciation - Generator Step-Ups																		
88	Depreciation - Interconnection Facilities																		
96	Common Depreciation - Electric Only	(Note A)	p336.11.b																
97	Common Amortization - Electric Only	(Note A)	p356 or p336.11d																

O&M Expenses

Line #s	Descriptions	Notes	Page #'s & Instructions	Previous Year Form 1Dec	Current Year Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Form 1 Dec	Totals	Non-electric Portion	Details
63	Transmission O&M	(Note A)	p321.112.b/Trans. Input Sht														-	0	
64	Generator Step-Ups		Input Sheet														216	0	
65	Transmission by Others		p321.96.b														-	0	

Wages & Salary

Line #s	Descriptions	Notes	Page #'s & Instructions	Previous Year Form 1Dec	Current Year Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Form 1 Dec	Totals	Non-electric Portion	Details
4	Total Wage Expense	(Note A)	p354.28b/Trans. Wksht																
5	Total A&G Wages Expense	(Note A)	p354.27b/Trans. Wksht																
1	Transmission Wages	(Note A)	p354.21b/Trans. Wksht																
2	Generator Step-Ups		Trans. Wksht																

Transmission / Non-transmission Cost Support

Line #s	Descriptions	Notes	Page #'s & Instructions	Previous Year Form 1Dec	Current Year Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Form 1 Dec	Average	Non-transmission Related	Details
30	**Plant Held for Future Use (Including Land)**	(Notes C & Q)	p214.47.d														0	0	Specific identification based on plant records: The following plant investments are included:
																Form 1 Amount	Transmission Related	Non-transmission Related	
																-		-	**Enter Details**

EPRI Dues Cost Support

Line #s	Descriptions	Notes	Page #'s & Instructions	Form 1 Amount	EPRI Dues	Details
	Allocated General & Common Expenses					
73	Less EPRI Dues	(Note D)	p352-353/Attachment 5			See Form 1

Regulatory Expense Related to Transmission Cost Support

Line #s	Descriptions	Notes	Page #'s & Instructions	Form 1 Amount	Transmission Related	Non-transmission Related	Details
	Allocated General & Common Expenses						
71	Less Regulatory Commission Exp Account 928	(Note E)	p323.189b/Attachment 5			0	See FERC Form 1 pages 350-351.
	Directly Assigned A&G						
77	Regulatory Commission Exp Account 928	(Note G)	p323.189b/Attachment 5		0		current case.

Safety Related Advertising Cost Support

Line #s	Descriptions	Notes	Page #'s & Instructions	Form 1 Amount	Safety Related	Non-safety Related	Details
	Directly Assigned A&G						
81	General Advertising Exp Account 930.1	(Note F)	Attachment 5			-	

MultiState Workpaper

Line #s	Descriptions	Notes	Page #'s & Instructions	State 1	State 2	State 3	State 4	State 5	Details
	Income Tax Rates								
				Va	NC	Wva			Enter Calculation
132	SIT=State Income Tax Rate or Composite	(Note I)							0.00%

Education and Out Reach Cost Support

Line #s	Descriptions	Notes	Page #'s & Instructions	Form 1 Amount	Education & Outreach	Other	Details
	Directly Assigned A&G						
78	General Advertising Exp Account 930.1	(Note K)	p323.191b			-	-

Excluded Plant Cost Support

Line #s	Descriptions	Notes	Page #'s & Instructions		0	Description of the Facilities
	Adjustment to Remove Revenue Requirements Associated with Excluded Transmission Facilities			Includes only the costs of any Interconnection Facilities constructed for VEPCO's own Generating Facilities after March 15, 2000 in accordance with Order 2003.	0	**General Description of the Facilities**
						None
						Add more lines if necessary

Instructions:

1. Remove all investment below 69 kV or generator step up transformers included in transmission plant in service that are not a result of the RTEP Process
2. If unable to determine the investment below 69kV in a substation with investment of 69 kV and higher as well as below 69 kV, the following formula will be used:

		Example
A	Total investment in substation	1,000,000
B	Identifiable investment in Transmission (provide workpapers)	500,000
C	Identifiable investment in Distribution (provide workpapers)	400,000
D	Amount to be excluded (A x (C / (B + C)))	444,444

Transmission Related Account 242 Reserves

Line #s	Descriptions	Notes	Page #'s & Instructions	Beginning Year Balance	End of Year Balance	Average Balance	Allocation	Transmission Related	Details
47	**Transmission Related Account 242 Reserves (exclude current year environmental site related reserves)**			Enter $	Enter $			Amount	
	Directly Assignable to Transmission					$ -	100%	-	
	Labor Related, General plant related or Common Plant related					$ -	#DIV/0!	#DIV/0!	
	Plant Related						#DIV/0!	#DIV/0!	
	Other					$ -	0.00%	-	
	Total Transmission Related Reserves					$ -		#DIV/0!	To line 49

Prepayments

Line #s	Descriptions	Notes	Page #'s & Instructions	Beginning Year Balance	End of Year Balance	Average Balance		To Line 50	Description of the Prepayments
48	**Prepayments**								
	Wages & Salary Allocator						#DIV/0!		
	Pension Liabilities, if any, in Account 242					$ -	#DIV/0!	#DIV/0!	
						$ -			
	Prepayments					$ -	#DIV/0!	#DIV/0!	
	Prepaid Pensions if not included in Prepayments					$ -	**#DIV/0!**	#DIV/0!	

Outstanding Network Credits Cost Support

Line #s	Descriptions	Notes	Page #'s & Instructions	Beginning Year Balance	End of Year Balance	Average Balance	Description of the Credits
	Network Credits						General Description of the Credits
58	Outstanding Network Credits	(Note N)	From PJM			$ -	None
59	Less Accumulated Depreciation Associated with Facilities with Outstanding Network Credits	(Note N)	From PJM			$ -	Add more lines if necessary

Extraordinary Property Loss

Line #s	Descriptions	Notes	Page #'s & Instructions	Amount	# of Years	Amortization	W/ interest	Amount	Number of years	Amortization
89										#DIV/0!

Interest on Outstanding Network Credits Cost Support

Line #s	Descriptions	Notes	Page #'s & Instructions	0	Description of the Interest on the Credits
				0	General Description of the Credits
				Enter $	None
					Add more lines if necessary

Facility Credits under Section 30.9 of the PJM OATT.

Line #s	Descriptions	Notes	Page #'s & Instructions	Amount	Description & PJM Documentation
	Revenue Requirement				
165	Facility Credits under Section 30.9 of the PJM OATT.			-	

PJM Load Cost Support

Line #s	Descriptions	Notes	Page #'s & Instructions	1 CP Peak	Description & PJM Documentation
	Network Zonal Service Rate			Enter	
169	1 CP Peak	(Note L)	PJM Data		

A&G Expenses - Other Post Employment Benefits

Line #s	Descriptions	Notes	Page #'s & Instructions	Amount
	Total A&G Expenses		p323.197b	
	Less OPEB Current Year			
	Plus: Stated OPEB (2008 actual)			
69	Current Year Total A&G Expenses			-

Issued By: Craig Glazer,
Vice President, Federal Government Policy
Issued On: October 25, 2007

Effective: January 1, 2008

Virginia Electric and Power Company
ATTACHMENT H-16A
Attachment 6 - True-up Adjustment for Network Integration Transmission Service

The True-Up Adjustment component of the Formula Rate for each Rate Year beginning with 2010 shall be determined as follows: 1

(i) Beginning with 2009, no later than June 15 of each year VEPCO shall recalculate an adjusted Annual Transmission Revenue Requirement for the previous calendar year based on its actual costs as reflected in its Form No. 1 and its books and records for that calendar year, consistent with FERC accounting policies. 2

(ii) VEPCO shall determine the difference between the recalculated Annual Transmission Revenue Requirement as determined in paragraph (i) above, and ATRR based on projected costs for the previous calendar year (True-Up Adjustment Before Interest).

(iii) The True-Up Adjustment shall be determined as follows:

True-Up Adjustment equals the True-Up Adjustment Before Interest multiplied by (1+i)^24 months

Where i = Sum of (the monthly rates for the 7 months ending July 31 of the current year and the monthly rates for the 12 months ending December 31 of the preceding year) divided by 19 months.

Each monthly rate used to calculate i shall be calculated pursuant to the Commission’s regulations at 18 C.F.R. § 35.19a.

Summary of Formula Rate Process including True-Up Adjustment

Month	Year	Action
Fall	2007	TO populates the formula with Year 2008 estimated data
Sept	2008	TO populates the formula with Year 2009 estimated data
June	2009	TO populates the formula with Year 2008 actual data and calculates the 2008 True-Up Adjustment Before Interest
Sept	2009	TO calculates the Interest to include in the 2008 True-Up Adjustment
Sept	2009	TO populates the formula with Year 2010 estimated data and 2008 True-Up Adjustment
June	2010	TO populates the formula with Year 2009 actual data and calculates the 2009 True-Up Adjustment Before Interest
Sept	2010	TO calculates the Interest to include in the 2009 True-Up Adjustment
Sept	2010	TO populates the formula with Year 2011 estimated data and 2009 True-Up Adjustment
June	(Year)	TO populates the formula with (Year -1) actual data and calculates the (Year-1) True-Up Adjustment Before Interest
Sept	(Year)	TO calculates the Interest to include in the (Year-1) True-Up Adjustment
Sept	(Year)	TO populates the formula with (Year +1) estimated data and (Year-1) True-Up Adjustment

1 No True-Up Adjustment will be included in the Annual Transmission Revenue Requirement for 2008 or 2009 since the Formula Rate was not in effect for 2006 or 2007.

2 To the extent possible each input to the Formula Rate used to calculate the actual Annual Transmission Revenue Requirement included in the True-Up Adjustment either will be taken directly from the FERC Form No. 1 or will be reconcilable to the FERC Form No. 1 by the application of clearly identified and supported information. If the reconciliation is provided through a worksheet included in the filed Formula Rate template, the inputs to the worksheet must meet this transparency standard, and doing so will satisfy this transparency requirement for the amounts that are output from the worksheet and input to the main body of the Formula Rate.

Calendar Year	Do for Each Calendar Year beginning in 2009
ATRR based on actual costs included for the previous calendar year but excludes the true-up adjustment.	
ATRR based on projected costs included for the previous calendar year but excludes the true-up adjustment.	
Difference	-
Future Value Factor (1+i)^24	1.00000
True-up Adjustment	0

Where:
i = interest rate as described in (iii) above.

Virginia Electric and Power Company
ATTACHMENT H-16A
Attachment 6A - True-up Adjustment for Annual Revenue Requirements recovered under Schedule 12

The True-Up Adjustment component of the annual revenue requirement for each project included in Attachment 7 for each Rate Year beginning with 2010 shall be determined as follows:[1]

(i) Beginning with 2009, no later than June 15 of each year VEPCO shall recalculate an adjusted Annual Revenue Requirement for the previous calendar year based on its actual costs as reflected in its Form No. 1 and its books and records for that calendar year, consistent with FERC accounting policies.[2]

(ii) VEPCO shall determine the difference between the recalculated Annual Revenue Requirement and the Annual Revenue Requirement based on its projections (True-Up Adjustment Before Interest).

(iii) The True-Up Adjustment for each project shall be determined as follows:

True-Up Adjustment equals the True-Up Adjustment Before Interest multiplied by (1+i)^24 months

Where i = Sum of (the monthly rates for the 7 months ending July 31 of the current year and the monthly rates for the 12 months ending December 31 of the proceeding year) divided by 19 months.

Each monthly rate used to calculate i shall be calculated pursuant to the Commission's regulations at 18 C.F.R. § 35.19a.

Summary of Formula Rate Process including True-Up Adjustment

Month	Year	Action
Fall	2007	TO populates the formula with Year 2008 estimated data
Sept	2008	TO populates the formula with Year 2009 estimated data
June	2009	TO populates the formula with Year 2008 actual data and calculates the 2008 True-Up Adjustment Before Interest
Sept	2009	TO calculates the Interest to include in the 2008 True-Up Adjustment
Sept	2009	TO populates the formula with Year 2010 estimated data and 2008 True-Up Adjustment
June	2010	TO populates the formula with Year 2009 actual data and calculates the 2009 True-Up Adjustment Before Interest
Sept	2010	TO calculates the Interest to include in the 2009 True-Up Adjustment
Sept	2010	TO populates the formula with Year 2011 estimated data and 2009 True-Up Adjustment
June	(Year)	TO populates the formula with (Year -1) actual data and calculates the (Year-1) True-Up Adjustment Before Interest
Sept	(Year)	TO calculates the Interest to include in the (Year-1) True-Up Adjustment
Sept	(Year)	TO populates the formula with (Year +1) estimated data and (Year-1) True-Up Adjustment

[1] No True-Up Adjustment will be included in the annual revenue requirements for 2008 or 2009 since the Formula Rate was not in effect for 2006 or 2007. For all true-up calculations, the ATRR will be adjusted to exclude any true-up adjustment.

[2] To the extent possible, each input to the Formula Rate used to calculate the actual Annual Revenue Requirement included in the True-Up Adjustment either will be taken directly from the FERC Form No. 1 or will be reconcilable to the FERC Form No. 1 by the application of clearly identified and supported information. If the reconciliation is provided through a worksheet included in the filed Formula Rate template, the inputs to the worksheet must meet this transparency standard, and doing so will satisfy this transparency requirement for the amounts that are output from the worksheet and input to the main body of the Formula Rate.

Virginia Electric and Power Company
ATTACHMENT H-16A
Attachment 7 - Transmission Enhancement Annual Revenue Requirement Worksheet
(dollars)

1	New Plant Carrying Charge			
2	**Fixed Charge Rate (FCR) if not a CIAC**			
		Formula Line		
3	A	154	Net Plant Carrying Charge without Depreciation	#DIV/0!
4	B	161	Net Plant Carrying Charge per 100 Basis Point increase in ROE without Depreciation	#DIV/0!
5	C		Line B less Line A	#DIV/0!
6	**FCR if a CIAC**			
7	D	155	Net Plant Carrying Charge without Depreciation, Return, or Income Taxes	#DIV/0!

8 **The FCR resulting from Formula is for the rate period only.**
9 **Therefore actual revenues collected or the lack of revenues collected in other years are not applicable.**

			Project A		Project B	
10	Details					
11	Schedule 12	(Yes or No)		b0217		b0222
12	Life			Upgrade Mt.Storm - Doubs 500 kV		Install 150 MVAR capacitor
13	FCR W/O incentive	Line 3				
14	Incentive Factor (Basis Points /100)					
15	FCR W incentive L.13 +(L.14*L.5)		#DIV/0!		#DIV/0!	
16	Investment					
17	Annual Depreciation Exp		#DIV/0!		-	
18	In Service Month (1-12)					

19		Invest Yr	Beginning	Depreciation	Ending	Rev Req	Beginning	Depreciation	Ending	Rev Req
20	W / O incentive	2006	-	#DIV/0!	#DIV/0!		-	-	-	-
21	W incentive	2006	-	#DIV/0!	#DIV/0!	-	-	-	-	-
22	W / O incentive	2007	#DIV/0!	#DIV/0!	#DIV/0!	-	-	-	-	-
23	W incentive	2007	#DIV/0!	#DIV/0!	#DIV/0!	-	-	-	-	-
24	W / O incentive	2008	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	-	-	-	-
25	W incentive	2008	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	-	-	-	#DIV/0!

Lines continues as new rate years as added.

In the formulas used in the Columns for lines 19+ are as follows:
"In Service Month" is the first month during the first year that the project is placed in service or recovery is request for the project.
"Beginning" is the investment on line 16 for the first year and is the "Ending" for the prior year after the first year.
"Depreciation" is the annual depreciation in line 17 divided by twelve times the difference of 12.5 minus line 18 in the first year and line 17 thereafter.
"Ending" is "Beginning" less "Depreciation"
Revenue Requirement used for crediting is ("Beginning" plus "Ending") divided by two times line 13 times the quotient of 12.5 minus line 18 divided by 12 plus "Depreciation" for the first year and ("Beginning" plus "Ending") divided by two times line 13 plus "Depreciation" thereafter.
Revenue Requirement used for charging is ("Beginning" plus "Ending") divided by two times line 15 times the quotient of 12.5 minus line 18 divided by 12 plus "Depreciation" for the first year and ("Beginning" plus "Ending") divided by two times line 15 plus "Depreciation" thereafter.
Formula Logic to be copied on new lines added each year after line 25. Using 2009 as an example, the logic will be included in lines 26 and 27.
Beginning with the annual revenue requirements determined in 2009 for 2010, the annual revenue requirements based on projected costs will include a True-Up Adjustment for the previous calendar year in accordance with Attachment 6 A and as calculated in Lines A through I below
Projected Revenue Requirements are calculated using the logic described for lines 19 + but with projected data for the indicated year.
Actual Revenue Requirements are calculated using the logic described for lines 19 + but with actual data for the indicated year.

Calendar Year — Do for Each Calendar Year beginning in 2009 for True-Up Adjustments applicable to 2010 annual revenue requirements.

		Project A	Project B
A	Projected Revenue Requirement without Incentive for Previous Calendar Year*		
B	Projected Revenue Requirement with Incentive for Previous Calendar Year*		
C	Actual Revenue Requirement without Incentive for Previous Calendar Year *		
D	Actual Revenue Requirement with Incentive for Previous Calendar Year *		
E	True-Up Adjustment Before Interest without Incentive for Next Calendar Year (C-A)	-	-
F	True-Up Adjustment Before Interest with Incentive for Previous Calendar Year (B-D)	-	-
G	Future Value Factor (1+i)^24 months from Attachment 6	-	-
H	True-Up Adjustment without Incentive (E*G)	-	-
I	True-Up Adjustment with Incentive (F*G)	-	-

* These amounts do not include any True-Up Adjustments.

Additional columns to be inserted after the last project as new projects are added to formula.

Virginia Electric and Power Company
ATTACHMENT H-16A
Attachment 7 - Transmission Enhancement Annual Revenue Requirement Worksheet
(dollars)

Project C				Project D				Project E			
	b0223 and b0224				B0225				B0226		
	Install 150 MVAR capacitors				Install 33 MVAR capacitor at Possum Pt. 115 kV				Install 500/230 kV transformer at Clifton and Clifton 500 KV 150 MVAR capacitor		
#DIV/0!				#DIV/0!				#DIV/0!			
-				-				-			
Beginning	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**
-	-	-	-	-	-	-	-	-	-	-	-
-	-	-	-	-	-	-	-	-	-	-	-
-	-	-	-	-	-	-	-	-	-	-	-
-	-	-	-	-	-	-	-	-	-	-	-
-	-	-	-	-	-	-	-	-	-	-	-
-	-	-	#DIV/0!	-	-	-	#DIV/0!	-	-	-	#DIV/0!

-	-	-
-	-	-
-	-	-
-	-	-
-	-	-

Virginia Electric and Power Company
ATTACHMENT H-16A
Attachment 7 - Transmission Enhancement Annual Revenue Requirement Worksheet
(dollars)

Project F				Project G				If Yes for Schedule 12 Include in this Total.	If No for Schedule 12 include in this Sum.	
	B0341				B0403					
	Install a breaker at Northern Neck 115 kV				2nd Dooms 500/230 kV transformer addition					
#DIV/0!				#DIV/0!						
-				-					Annual Revenue Requirement including Incentive if Applicable	Annual Revenue Requirement excluding Incentive
Beginning	Depreciation	Ending	Rev Req	Beginning	Depreciation	Ending	Rev Req	Total	Sum	Sum
-	-	-						$ -		
-	-	-						$ -		
-	-	-		-	-	-		$ -		
-	-	-		-	-	-		$ -		
-	-	-	-	-	-	-	-	#DIV/0!		$ -
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Virginia Electric and Power Company
ATTACHMENT H-16A
Attachment 8 - Securitization Workpaper
(000's)

Line #		
	Long Term Interest	
105	**Less LTD Interest on Securitization Bonds**	0
	Capitalization	
115	**Less LTD on Securitization Bonds**	0

Virginia Electric and Power Company
ATTACHMENT H-16A
Attachment 9 - Depreciation Rates[1]

Plant Type	Applied Depreciation Rate
Transmission	1.97%
General	
Structures and Improvements	1.86%
Communication Equipment	3.67%
Computer Equipment	16.51%
Furniture, Equipment and Office Machines	1.64%
Laboratory and Miscellaneous Equipment	4.10%
Stores and Power Operated Equipment	6.31%
Tools, Shop, Garage, and Other Tangible Equipment	4.93%

[1]Depreciation rates may be changed only pursuant to a Section 205 or Section 206 proceeding.

ATTACHMENT H-16B

FORMULA RATE IMPLEMENTATION PROTOCOLS

Section 1 Annual Updates

a. No later than September 15 of each year, VEPCO shall cause to be posted on the www.PJM.com website the following information (the "Annual Update"):

(i) VEPCO's Annual Transmission Revenue Requirement ("ATRR"), rate for Network Integration Transmission Service ("NITS"), based on applying its projected costs, revenues and credits, other than those credits that will be distributed to customers pursuant to section 2 of Attachment H-16, for the next calendar year, plus its True-up Adjustment calculated pursuant to the Formula Rate set out in Attachment H-16A,

(ii) an estimate of the Network Service Peak Load of the Dominion Zone that will be used by the Transmission Provider to determine each Network Customer's Zone Network Load pursuant to Section 34.1 and Attachment H-16 for the next calendar year; and

(iii) an explanation of any change in VEPCO's accounting policies and practices that took effect in the preceding twelve months ending August 31 that is reported in Notes 3 and 4 of VEPCO's Securities and Exchange Commission Form 10-Q ("Material Accounting Changes"). To the extent there are Material Accounting Changes, VEPCO's Form 10-Q will be posted on PJM's website at the time of the Annual Update.

b. Upon written request, VEPCO will make available to any entity that is or may become a customer taking transmission service on the VEPCO facilities operated by the Transmission Provider and any state regulatory commission with jurisdiction over the VEPCO facilities located in the area served by the Transmission Provider (an "Interested Party") a "workable" Excel file containing that year's Annual Update data.

c. No later than September 30 of each year, VEPCO shall hold a public meeting to explain the Annual Update for the next calendar year. VEPCO shall modify the Annual Update to reflect any changes that it and the Interested Parties agree upon by no later than November 30, and shall cause the revised Annual Update to be posted on the www.PJM.com website no later than December 15. VEPCO shall cause the Annual Update, as revised pursuant to the procedures set out above, to be included in an informational filing with the Commission by no later than December 15. This filing will not require Commission action.

d. The ATRR and the Rate for Network Integration Transmission Service, determined pursuant to Section 1.a above and adjusted pursuant to Sections 2 and 3, below, shall be effective for the next calendar year.

e. If after September 15, PJM determines the actual Network Service Peak Load for the Dominion Zone that will be used by the Transmission Provider to determine each Network Customer's Zone Network Load pursuant to Section 34.1 and Attachment H-16 for the next calendar year differs from the value posted pursuant to Section 1.a.ii., above, the Rate for Network Integration Transmission Service shall be adjusted to reflect the updated Network Service Peak Load and VEPCO shall cause an updated calculation of the Rate for Network Integration Transmission Service to be posted on the www.PJM.com website no later than fifteen (15) business days following the posting by PJM of the actual Network Service Peak Load for the Dominion Zone.

Section 2 Annual Review Procedures

a. No later than June 15 of each year, VEPCO shall cause to be posted on the www.PJM.com website the following information:

(i) the adjusted ATRR for the previous calendar year, calculated by applying the methodology set out in Attachment H-16A Appendix A to VEPCO's actual costs for that calendar year; and

(ii) the True-Up Adjustment Before Interest for the previous calendar year, calculated pursuant to Attachment H-16A, Attachment 6**.**

b. No later than October 1 of each year, any Interested Party may serve information requests on VEPCO concerning the adjusted ATRR for the previous calendar year and the True-Up Adjustment ("Information Requests"). Information Requests shall be limited to what is necessary to determine whether VEPCO has properly calculated the True-Up Adjustment and its components and the procedures in this Attachment H-16B. Information Requests shall not (i) otherwise be directed to ascertaining whether the Formula Rate is just and reasonable; (ii) solicit information concerning costs or allocations where the costs or allocation method have been determined by FERC or resolved by a settlement accepted by FERC or in the context of other True-up Adjustments, except that such information requests shall be permitted if they seek to determine if there has been a material change in circumstances. Interested Parties shall make good faith efforts to submit consolidated sets of information requests that limit the number and overlap of questions to the maximum extent practicable.

c. VEPCO shall make a good faith effort to respond to the Information Requests within fifteen (15) business days of receipt of such requests. VEPCO may give reasonable priority to responding to Information Requests that satisfy the practicable coordination and consolidation provision of Section 2.b. above.

Section 3 Challenges to True-Up Adjustments

a. No later than November 1 of each year, any Interested Party may notify VEPCO in writing of any specific challenges to any component of the most recently-posted True-Up Adjustment and any Material Accounting Change identified pursuant to Section 1.a(iii), above that affects the True-Up Adjustment ("Preliminary Challenge"). VEPCO shall promptly cause the Preliminary Challenge to be posted on the www.PJM.com website. VEPCO and the Interested Party shall make good faith efforts to resolve the Preliminary Challenge through negotiations. Any modification to the True-Up Adjustment or any Material Accounting Change that results from such negotiations and that is agreed upon no later than November 30 shall be promptly posted on the website and incorporated into the Annual Update for the next calendar year.

b. Any Interested Party that has not resolved its Preliminary Challenge to a True-Up Adjustment or a Material Accounting Change that affects the True-Up Adjustment may, no later than December 16 of each year, file with the FERC a Complaint pursuant to 18 C.F.R. § 385.206. Such Interested Party may not raise in its Complaint any matter that it did not raise in its Preliminary Challenge with respect to that True-Up Adjustment or Material Accounting Change. The FERC's Rules of Practice and Procedure shall govern any such Complaint.

c. An Interested Party's failure to make a Preliminary Challenge with respect to a component of the True-Up Adjustment or a Material Accounting Change that affects that True-Up Adjustment shall not bar the Interested Party from making a Preliminary Challenge related to a subsequent True-Up Adjustment or to the same Material Accounting Change to the extent such Material Accounting Change affects a subsequent True-Up Adjustment.

d. In any Complaint proceeding or proceeding initiated *sua sponte* by the FERC challenging a True-Up Adjustment or a Material Accounting Change, VEPCO shall bear the burden of proving that it has reasonably calculated the True-Up Adjustment and/or reasonably adopted and applied the Material Accounting Change.

e. Any changes to the data inputs, including but not limited to revisions to VEPCO's FERC Form No. 1, resulting from Preliminary Challenges or proceedings before the FERC, including proceedings initiated pursuant to Section 3.b above and proceedings initiated *sua sponte* by the FERC, that are not agreed upon no later than November 30 shall be incorporated into the Formula Rate and the True-Up Adjustment for the next calendar year that commences after the negotiations or proceedings become final. This reconciliation mechanism shall apply in lieu of mid-year adjustments, refunds or surcharges to rates. However, in the event that the Formula Rate is replaced by a stated rate for VEPCO, actual refunds or surcharges (with interest determined in accordance with 18 C.F.R. §35.19a) shall be made no later than thirty (30) days after the effective date of the stated rate established by FERC.

f. The True-Up Adjustment, any Material Accounting Change and the resulting ATRR shall become final and no longer subject to challenge pursuant to this Attachment H-16B or by any other means by the FERC or by any other entity on the later of (i) December 16 of the year in which they are posted if as of that date no entity has filed a Complaint pursuant to Section 3.b above and the FERC has not initiated a proceeding *sua sponte* to consider the True-Up Adjustment or Material Accounting Change; or (ii) a final FERC order issued in response to a Complaint or a proceeding initiated by FERC to consider the True-Up Adjustment.

Section 4 Proceedings to Modify the Formula Rate or Stated Components of the Formula Rate

a. Except as specifically provided herein, nothing herein shall be deemed to limit in any way the right of VEPCO to file unilaterally, pursuant to Section 205 of the Federal Power Act and the regulations thereunder, to modify the Formula Rate or stated components of the Formula Rate (including, but not limited to, the rate of return on equity, the depreciation rates and Post-Employment Benefits other than Pensions (“PBOP”)); or to replace the Formula Rate with a stated rate; or the right of any other entity to request such changes pursuant to Section 206 of the Federal Power Act and the regulations thereunder.

Virginia Electric and Power Company
ATTACHMENT H-16A
Formula Rate -- Appendix A

Shaded cells are input cells

Line	Description	Notes	FERC Form 1 Page # or Instruction (Note H)		2008 (000's)
	Allocators				
	Wages & Salary Allocation Factor				
1	Transmission Wages Expense		p354.21b/ Attachment 5	$	15,066
2	Less Generator Step-ups		Attachment 5		136
3	Net Transmission Wage Expenses		(Line 1 - 2)		14,930
4	Total Wages Expense		p354.28b/Attachment 5		554,521
5	Less A&G Wages Expense		p354.27b/Attachment 5		126,603
6	Total		(Line 4 - 5)	$	427,918
7	**Wages & Salary Allocator**	(Note B)	(Line 3 / 6)		**3.4890%**
	Plant Allocation Factors				
8	Electric Plant in Service	(Notes A& Q)	p207.104.g/Attachment 5	$	22,425,689
9	Common Plant In Service - Electric		(Line 26)		0
10	Total Plant In Service		(Sum Lines 8 & 9)		22,425,689
11	Accumulated Depreciation (Total Electric Plant)	(Notes A & Q)	(Line 15 - 14 - 13 -12)		9,007,346
12	Accumulated Intangible Amortization	(Notes A & Q)	p200.21c/Attachment 5		180,407
13	Accumulated Common Amortization - Electric	(Notes A & Q)	p356/Attachment 5		0
14	Accumulated Common Plant Depreciation - Electric	(Notes A & Q)	p356/Attachment 5		0
15	Total Accumulated Depreciation		p219.29c/Attachment 5		9,187,753
16	Net Plant		(Line 10 - 15)		13,237,936
17	Transmission Gross Plant		(Line 31 - 30)		1,921,752
18	**Gross Plant Allocator**	(Note B)	(Line 17 / 10)		**8.5694%**
19	Transmission Net Plant		(Line 44 - 30)	$	1,079,693
20	**Net Plant Allocator**	(Note B)	(Line 19 / 16)		**8.1561%**
	Plant Calculations				
	Plant In Service				
21	Transmission Plant In Service	(Notes A & Q)	p207.58.g/Attachment 5	$	1,965,395
22	Less: Generator Step-ups	(Notes A & Q)	Attachment 5		75,343
23	Less: Interconnect Facilities Installed After March 15, 2000	(Notes A & Q)	Attachment 5		0
24	**Total Transmission Plant In Service**		(Lines 21 - 22 - 23)		**1,890,052**
25	General & Intangible	(Notes A & Q)	p205.5.g + p207.99.g/Attachment 5		908,570
26	Common Plant (Electric Only)		p356/Attachment 5		0
27	Total General & Common		(Line 25 + 26)		908,570
28	Wage & Salary Allocation Factor		(Line 7)		3.4890%
29	**General & Common Plant Allocated to Transmission**		(Line 27 * 28)	**$**	**31,700**
30	**Plant Held for Future Use (Including Land)**	(Notes C & Q)	p214.47.d/Attachment 5	**$**	**3,563**
31	**TOTAL Plant In Service**		**(Line 24 + 29 + 30)**	**$**	**1,925,315**
	Accumulated Depreciation				
32	Transmission Accumulated Depreciation	(Notes A & Q)	p219.25.c/Attachment 5	$	824,688
33	Less Accumulated Depreciation for Generator Step-ups	(Notes A & Q)	Attachment 5		2,202
34	Less Accumulated Depreciation for Interconnect Facilities Installed After March 15, 2000	(Notes A & Q)	Attachment 5		0
35	Total Accumulated Depreciation for Transmission		(Line 32 - 33 - 34)		822,486
36	Accumulated General Depreciation	(Notes A & Q)	p219.28.b/Attachment 5		380,573
37	Accumulated Intangible Amortization	(Notes A & Q)	(Line 12)		180,407
38	Accumulated Common Amortization - Electric		(Line 13)		0
39	Common Plant Accumulated Depreciation (Electric Only)		(Line 14)		0
40	Total Accumulated Depreciation		(Sum Lines 36 to 39)		560,980
41	Wage & Salary Allocation Factor		(Line 7)		3.4890%
42	**General & Common Allocated to Transmission**		(Line 40 * 41)		**19,573**
43	**TOTAL Accumulated Depreciation**		**(Line 35 + 42)**	**$**	**842,058**
44	**TOTAL Net Property, Plant & Equipment**		**(Line 31 - 43)**	**$**	**1,083,256**

Virginia Electric and Power Company
ATTACHMENT H-16A
Formula Rate -- Appendix A

Line		Notes	FERC Form 1 Page # or Instruction (Note H)		2008
	Adjustment To Rate Base				
	Accumulated Deferred Income Taxes				
45	ADIT net of FASB 106 and 109		Attachment 1	$	(152,540)
46	**Accumulated Deferred Income Taxes Allocated To Transmission**		(Line 45)	**$**	**(152,540)**
	Transmission O&M Reserves				
47	**Total Balance Transmission Related Account 242 Reserves**	Enter Negative	Attachment 5	**$**	**(272)**
	Prepayments				
48	Prepayments	(Notes A & R)	Attachment 5	$	2,575
49	**Total Prepayments Allocated to Transmission**		(Line 48)	**$**	**2,575**
	Materials and Supplies				
50	Undistributed Stores Exp	(Notes A & R)	p227.6c & 16.c	$	-
51	Wage & Salary Allocation Factor		(Line 7)		3.4890%
52	Total Transmission Allocated Materials and Supplies		(Line 50 * 51)		0
53	Transmission Materials & Supplies		p227.8c/2		3,078
54	**Total Materials & Supplies Allocated to Transmission**		(Line 52 + 53)	**$**	**3,078**
	Cash Working Capital				
55	Transmission Operation & Maintenance Expense		(Line 85)	$	48,837
56	1/8th Rule		x 1/8		12.5%
57	**Total Cash Working Capital Allocated to Transmission**		(Line 55 * 56)	**$**	**6,105**
	Network Credits				
58	Outstanding Network Credits	(Note N)	Attachment 5 / From PJM		0
59	Less Accumulated Depreciation Associated with Facilities with Outstanding Network Credits	(Note N)	Attachment 5 / From PJM		0
60	Net Outstanding Credits		(Line 58 - 59)		**0**
61	**TOTAL Adjustment to Rate Base**		(Line 46 + 47 + 49 + 54 + 57 - 60)	**$**	**(141,055)**
62	**Rate Base**		(Line 44 + 61)	**$**	**942,201**
	O&M				
	Transmission O&M				
63	Transmission O&M		p321.112.b/Attachment 5	$	37,744
64	Less GSU Maintenance		Attachment 5		216
65	Less Account 565 - Transmission by Others		p321.96.b/Attachment 5		0
66	Plus Schedule 12 Charges billed to Transmission Owner and booked to Account 565	(Note O)	PJM Data		0
67	**Transmission O&M**		(Lines 63 - 64 + 65 + 66)	**$**	**37,528**
	Allocated General & Common Expenses				
68	Common Plant O&M	(Note A)	p356		0
69	Total A&G		Attachment 5		339,538
70	Less Property Insurance Account 924		p323.185b		7,974
71	Less Regulatory Commission Exp Account 928	(Note E)	p323.189b/Attachment 5		24,106
72	Less General Advertising Exp Account 930.1		p323.911b/Attachment 5		2,629
73	Less EPRI Dues	(Note D)	p352-353/Attachment 5		4,055
74	**General & Common Expenses**		(Lines 68 + 69) - Sum (70 to 73)	$	300,774
75	Wage & Salary Allocation Factor		(Line 7)		3.4890%
76	**General & Common Expenses Allocated to Transmission**		(Line 74 * 75)	**$**	**10,494**
	Directly Assigned A&G				
77	Regulatory Commission Exp Account 928	(Note G)	p323.189b/Attachment 5	$	164
78	General Advertising Exp Account 930.1	(Note K)	p323.191b		0
79	Subtotal - Transmission Related		(Line 77 + 78)		**164**
80	Property Insurance Account 924		p323.185b		7,982
81	General Advertising Exp Account 930.1	(Note F)	Attachment 5		0
82	Total		(Line 80 + 81)		7,982
83	Net Plant Allocation Factor		(Line 20)		8.1561%
84	**A&G Directly Assigned to Transmission**		(Line 82 * 83)	**$**	**651**
85	**Total Transmission O&M**		**(Line 67 + 76 + 79 + 84)**	**$**	**48,837**

Virginia Electric and Power Company
ATTACHMENT H-16A
Formula Rate -- Appendix A

Line	Description		Notes	FERC Form 1 Page # or Instruction (Note H)		2008
	Depreciation & Amortization Expense					
	Depreciation Expense					
86	Transmission Depreciation Expense		(Notes A and S)	p336.7b&c/Attachment 5	**$**	**38,158**
87	Less: GSU Depreciation			Attachment 5		**1,501**
88	Less Interconnect Facilities Depreciation			Attachment 5		**0**
89	Extraordinary Property Loss			Attachment 5		**0**
90	Total Transmission Depreciation			(Line 86 - 87 - 88 + 89)		**36,657**
91	General Depreciation		(Note A)	p336.10b&c&d/Attachment 5		29,527
92	Intangible Amortization		(Note A)	p336.1d&e/Attachment 5		32,992
93	Total			(Line 91 + 92)		**62,519**
94	Wage & Salary Allocation Factor			(Line 7)		3.4890%
95	**General and Intangible Depreciation Allocated to Transmission**			(Line 93 * 94)		**2,181**
96	Common Depreciation - Electric Only		(Note A)	p336.11.b		0
97	Common Amortization - Electric Only		(Note A)	p356 or p336.11d		0
98	Total			(Line 96 + 97)		0
99	Wage & Salary Allocation Factor			(Line 7)		3.4890%
100	**Common Depreciation - Electric Only Allocated to Transmission**			(Line 98 * 99)		**0**
101	**Total Transmission Depreciation & Amortization**			**(Line 90 + 95 + 100)**	**$**	**38,838**
	Taxes Other than Income					
102	**Taxes Other than Income**			Attachment 2	**$**	**10,215**
103	**Total Taxes Other than Income**			**(Line 102)**	**$**	**10,215**
	Return / Capitalization Calculations					
	Long Term Interest					
104	Long Term Interest		(Note T)	p117.62c through 67c	$	271,886
105	Less LTD Interest on Securitization Bonds		(Note P)	Attachment 8		0
106	**Long Term Interest**			(Line 104 - 105)	$	271,886
107	**Preferred Dividends**		(Note T), enter positive	p118.29c	$	15,721
	Common Stock					
108	Proprietary Capital			p112.16c,d/2	$	5,588,155
109	Less Preferred Stock		(Note T), enter negative	(Line 117)		-259,014
110	Less Account 219 - Accumulated Other Comprehensive Income		(Note T), enter negative	p112.15c,d/2		-122,504
111	**Common Stock**			(Sum Lines 108 to 110)	$	5,206,637
	Capitalization					
112	Long Term Debt			p112.24c,d/2	$	4,326,482
113	Less Loss on Reacquired Debt		(Note T), enter negative	p111.81c,d/2		-1,516
114	Plus Gain on Reacquired Debt		(Note T), enter positive	p113.61c,d/2		0
115	Less LTD on Securitization Bonds	(Note P)	(Note T), enter negative	Attachment 8		0
116	Total Long Term Debt			(Sum Lines 112 to 115)		4,324,966
117	Preferred Stock		(Note T), enter positive	p112.3c,d/2		259,014
118	Common Stock			(Line 111)		5,206,637
119	**Total Capitalization**			(Sum Lines 116 to 118)	$	9,790,617
120	Debt %	Total Long Term Debt		(Line 116 / 119)		44.2%
121	Preferred %	Preferred Stock		(Line 117 / 119)		2.6%
122	Common %	Common Stock		(Line 118 / 119)		53.2%
123	Debt Cost	Total Long Term Debt		(Line 106 / 116)		0.0629
124	Preferred Cost	Preferred Stock		(Line 107 / 117)		0.0607
125	Common Cost	Common Stock	(Note J)	Fixed		0.1140
126	Weighted Cost of Debt	Total Long Term Debt (WCLTD)		(Line 120 * 123)		0.0278
127	Weighted Cost of Preferred	Preferred Stock		(Line 121 * 124)		0.0016
128	Weighted Cost of Common	Common Stock		(Line 122 * 125)		0.0606
129	**Total Return (R)**			(Sum Lines 126 to 128)		**0.0900**
130	**Investment Return = Rate Base * Rate of Return**			**(Line 62 * 129)**		**84,799**

Virginia Electric and Power Company
ATTACHMENT H-16A
Formula Rate -- Appendix A

Line	Description	Notes	FERC Form 1 Page # or Instruction (Note H)		2008
	Composite Income Taxes				
	Income Tax Rates				
131	FIT=Federal Income Tax Rate		Attachment 5		35.00%
132	SIT=State Income Tax Rate or Composite	(Note I)	Attachment 5		6.23%
133	p	(percent of federal income tax deductible for state purposes)	Per State Tax Code		0.00%
134	T	T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =			39.05%
135	T/ (1-T)				64.07%
	ITC Adjustment	(Note I)			
136	Amortized Investment Tax Credit	enter negative	Attachment 1	$	(1,050)
137	T/(1-T)		(Line 135)		64.07%
138	**ITC Adjustment Allocated to Transmission**		(Line 136 * (1 + 137))	**$**	**(1,723)**
139	**Income Tax Component =**	CIT=(T/1-T) * Investment Return * (1-(WCLTD/R)) =	[Line 135 * 130 * (1-(126 / 129))]		**37,565**
140	**Total Income Taxes**		**(Line 138 + 139)**	**$**	**35,843**
	REVENUE REQUIREMENT				
	Summary				
141	Net Property, Plant & Equipment		(Line 44)	$	1,083,256
142	Adjustment to Rate Base		(Line 61)		-141,055
143	**Rate Base**		(Line 62)	**$**	**942,201**
144	O&M		(Line 85)		48,837
145	Depreciation & Amortization		(Line 101)		38,838
146	Taxes Other than Income		(Line 103)		10,215
147	Investment Return		(Line 130)		84,799
148	Income Taxes		(Line 140)		35,843
149					
150	**Revenue Requirement**		**(Sum Lines 144 to 149)**	**$**	**218,531**
	Net Plant Carrying Charge				
151	Revenue Requirement		(Line 150)	**$**	**218,531**
152	Net Transmission Plant		(Line 24 - 35)		**1,067,566**
153	Net Plant Carrying Charge		(Line 151 / 152)		**20.4700%**
154	Net Plant Carrying Charge without Depreciation		(Line 151 - 86) / 152		**16.8957%**
155	Net Plant Carrying Charge without Depreciation, Return or Income Taxes		(Line 151 - 86 - 130 - 140) / 152		**5.5951%**
	Net Plant Carrying Charge Calculation per 100 Basis Point increase in ROE				
156	Gross Revenue Requirement Less Return and Taxes		(Line 150 - 147 - 148)	**$**	**97,890**
157	Increased Return and Taxes		Attachment 4		**128,862**
158	Net Revenue Requirement per 100 Basis Point increase in ROE		(Line 156 + 157)		**226,752**
159	Net Transmission Plant		(Line 152)		**1,067,566**
160	Net Plant Carrying Charge per 100 Basis Point increase in ROE		(Line 158 / 159)		**21.2401%**
161	Net Plant Carrying Charge per 100 Basis Point increase in ROE without Depreciation		(Line 158 - 86) / 159		**17.6658%**
162	**Revenue Requirement**		(Line 150)	**$**	**218,531**
163	True-up Adjustment		Attachment 6		**-**
164	Plus any increased ROE calculated on Attachment 7 other than PJM Schedule 12 projects.		Attachment 7		**-**
165	Facility Credits under Section 30.9 of the PJM OATT.		Attachment 5		**-**
166	Revenue Credits		Attachment 3		**(9,370)**
167	Interest on Network Credits		PJM data		0
168	**Annual Transmission Revenue Requirement (ATRR)**		(Line 162 + 163 +164 + 165 + 166 + 167)	**$**	**209,161**
	Rate for Network Integration Transmission Service				
169	1 CP Peak	(Note L)	PJM Data		**19,688**
170	Rate ($/MW-Year)		(Line 168 / 169)		**10,623.79**
171	**Rate for Network Integration Transmisson Service Rate ($/MW/Year)**		**(Line 170)**		**10,623.79**

Virginia Electric and Power Company ATTACHMENT H-16A Formula Rate -- Appendix A	Notes	FERC Form 1 Page # or Instruction (Note H)	2008

Notes

A Electric portion only - VEPCO does not have Common Plant.
B Excludes amounts for Generator Step-ups and Interconnection Facilities, when appropriate.
C Includes Transmission portion only.
D Excludes all EPRI Annual Membership Dues.
E Includes all regulatory commission expenses.
F Includes all safety related advertising included in Account 930.1.
G Includes all regulatory commission expenses directly related to transmission service, RTO filings, or transmission siting itemized in Form 1 at 351.h.
H The Form 1 reference incates only the end-of-year balance used to derive the amount beside the reference. Each plant balance with a Form 1 reference will include the Form 1 balance in an average of the 13 month blances for the year. Each non-plant balance included in rate base with a Form 1 reference will include Form 1 balances in the calculation of the average of the beginning and end of year balances for the year. See notes Q and R below.
I 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 includes taxes in more than one state, it must explain in Attachment 5 the name of each state and how the blended or composite SIT was developed. Furthermore, a utility that elected to use 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). A utility must not include tax credits as a reduction to rate base and as an amortization against taxable income.
J ROE will be supported in the original filing and no change in ROE will be made absent a filing at FERC. The basis point increase in ROE for new investment will be set at 100 basis points in Attachment 4 but not applied to determine any of the charges resulting from this formula absent absent a filing at FERC.
K Education and outreach expenses relating to transmission, for example siting or billing.
L As provided for in Section 34.1 of the PJM OATT.
M Amount of transmission plant excluded from rates per Attachment 5.
N Outstanding Network Credits is the balance of Network Facilities Upgrades Credits due Transmission Customers who have made lump-sum payments (net of accumulated depreciation) toward the construction of Network Transmission Facilities consistent with Paragraph 657 of Order 2003-A. Interest on the Network Credits as booked each year is added to the revenue requirement on Line 167.
O Payments made under Schedule 12 of the PJM OATT that are not directly assessed to load in the Zone under Schedule 12 are included in Transmission O&M. If they are booked to Acct 565, they are included on Line 66.
P Securitization bonds may be included in the capital structure.
Q Calculated using 13 month average balance. Only beginning and end of year balances are from Form 1.
R Calculated using average of beginning and end of year balances. Beginning and end of year balances are from Form 1.
S The depreciation rates are included in Attachment 9.
T For the intial formula rate calculation, the projected capital structure shall reflect the capital structure from the 2006 FERC Form No. 1 data. For all other formula rate calculations, the projected capital structure and actual capital structure shall reflect the capital structure from the most recent FERC Form No. 1 data available.

END

Virginia Electric and Power Company
ATTACHMENT H-16A
Attachment 1 - Accumulated Deferred Income Taxes (ADIT) Worksheet - December 31,2008

	Only Transmission Related	*Plant Related*	*Labor Related*	*Total ADIT*
ADIT- 282	(160,740,479)	(87,601,543)	(22,758,611)	
ADIT-283	2,352,864	(6,758,046)	(1,170,684)	
ADIT-190	0	138,647,731	55,564,546	
Subtotal	(158,387,615)	44,288,142	31,635,251	
Wages & Salary Allocator			3.4890%	
Gross Plant Allocator		8.5694%		
End of Year ADIT	(158,387,615)	3,795,237	1,103,750	(153,488,628)
End of Previous Year ADIT (from Sheet 1A-ADIT (3))	(157,080,388)	4,832,781	656,136	(151,591,470)
Average Beginning and End of Year ADIT	(157,734,001)	4,314,009	879,943	(152,540,049)

End of Year ADIT	(153,488,628)
End of Previous Year ADIT	(151,591,470)
Average Beginning and End of Year ADIT	(152,540,049)

In filling out this attachment, a full and complete description of each item and justification for the allocation to Columns B-E and each separate ADIT item will be listed. Dissimilar items with amounts exceeding $100,000 will be listed separately.

End of Year Balances :

A *ADIT-190*	B *Total*	C *Production Or Other Related*	D *Only Transmission Related*	E *Plant Related*	F *Labor Related*	G *Justification*
BAD DEBTS	4,837,795	4,837,795				For tax purposes bad debts are deductible when they are deemed to be uncollectible / worthless.
EPA AUCTION PROCEEDS	2,314,446	2,314,446				Book expense for emissions allowances based on moving-average-cost, tax expense based on specific identification.
FLEET LEASE CREDIT - CURRENT	58,719			58,719		Books amortize the fleet lease extension credit over the new lease; tax takes the deduction when incurred.
GROSS REC-UNBILLED REV-NC	90,408	90,408				Books include income when meter is read; taxed when service is provided.
NUCLEAR FUEL - PERMANENT DISPOSAL	2,938	2,938				Books estimate expense, tax deduction taken when paid.
SEPARATION/ERT	60,427				60,427	Book amount accrued and expensed; tax deduction when paid.
SO2 ALLOWANCES - CURRENT	28,999	28,999				Book expense for emissions allowances based on moving-average-cost, tax expense based on specific identification.
SUCCESS SHARE PLAN	419,465				419,465	Book amount accrued as its earned; tax deduction is actual payout
VA PROPERTY TAX	3,131,384			3,131,384		Property tax expense is accrued for accounting purposes using the prior year's rates on the balance of the property located in the state at December 31 of the previous year. Tax takes a deduction when paid.
WEST VA PROPERTY TAX	2,323,235	2,323,235				Property tax expense is accrued for accounting purposes using the prior year's rates on the balance of the property located in the state at December 31 of the previous year. Tax takes a dedution when paid.
CAP EXPENSE	5,221,145			5,221,145		Represents 162 deduction for tax; capital for books.
CAPITALIZED INTEREST OPERATING CWIP	65,256,529	65,256,529				Represents tax capitalized interest on projects in CWIP - increase in taxable income.
CAPITALIZED INTEREST OPERATING IN SERVICE	(613,080)			(613,080)		Represents tax "In Service" capitalized Interest placed in service net of tax amortization.
CAPITALIZED INTEREST OPERATING IN SERVICE	111,595,471			111,595,471		Represents tax "In Service" capitalized Interest placed in service net of tax amortization.
DECOMMISSIONING & DECONTAMINATION	697,180	697,180				Book expensed as billed over 15 yr assessment period; tax deduct in year of assessment because all events test met as liability is based on prior facility use.
DECOMMISSIONING & DECONTAMINATION	929,573	929,573				Book expensed as billed over 15 yr assessment period; tax deduct in year of assessment because all events test met as liability is based on prior facility use.
DEFERRED GAIN/LOSS OPERATING	8,721,910			8,721,910		Represents the ADIT on Book Gain/Loss as accrued.
DSM	1,307,601	1,307,601				Represents a regulatory asset associated with Demand Side Mgt. Program that is being amortized for books.
EARNEST MONEY	12,692	12,692				Represents advances not recognized for tax.
FAS 143 ASSET OBLIGATION	10,215,580	10,215,580				Represents ARO accruals not deductible for tax.
FAS143 DECOMMISSIONING	293,724,843	293,724,843				Represents ARO accruals not deductible for tax.
FLEET LEASE CREDIT - NONCURRENT	213,571			213,571		Books amortizes the fleet lease extension credit over the new lease; tax takes the deduction when incurred.
GAIN(LOSS) INTERCO SALES -BOOK/TAX	4,747,884			4,747,884		Tax recognizes the intercompany gain/loss over the tax life of the assets.
GENERAL BUSINESS CREDITS	2,342,401			2,342,401		Represents business credits not expensed through current due to consolidated return limitations.
INT STOR NORTH ANNA	8,367,504	8,367,504				Books recognizes the expense as incurred. For tax the deduction is recognized when the casks are filled.
INT STOR SURRY	3,619,811	3,619,811				Books recognizes the expense as incurred. For tax the deduction is recognized when the casks are filled.
LONG TERM DISABILITY RESERVE	3,810,955				3,810,955	Book estimate accrued and expensed; tax deduction when paid.
METERS	3,272,689	3,272,689				Books pre-capitalize when purchased; tax purposes when installed.
OPEB	19,436,612				19,436,612	Represents the difference between the book accrual expense and the actual funded amount.
POWER PURCHASE BUYOUT	405,533	405,533				Represents the difference between the book accrual expense and the actual funded amount.
PREMIUM, DEBT, DISCOUNT AND EXPENSE	2,959,229			2,959,229		Books record the yield to maturity method; taxes amortize staight line.
REACQUIRED DEBT GAIN(LOSS)	1,092,599			1,092,599		Amortized for books and expensed for tax purposes.
REACTOR DECOMMISSIONING LIABILITY	910,000	910,000				Represents the difference between the accrual and payments.
REGULATORY LIABILITY - FAS 143	4,592,488	4,592,488				Represents regulatory liability established due to adoption of FAS 143.
RETIREMENT - (FASB 87)	31,837,087				31,837,087	Book estimate accrued and expensed; tax deduction when paid.
W.VA. STATE NOL CFWD - FEDERAL EFFECT	(823,502)			(823,502)		Federal effect of state deductions.
W.VA. STATE POLLUTION CONTROL - FEDERAL EFFECT	8,218,858	8,218,858				Federal effect of state deductions.
FAS 109 ITC REG LIABILITY	11,285,191	11,285,191				Represents the tax effect of ITC that will be refunded to the customer.
Subtotal - p234	616,626,170	422,413,893	0	138,647,731	55,564,546	
Less FASB 109 Above if not separately removed			0			
Less FASB 106 Above if not separately removed			0		0	
Total	616,626,170	422,413,893	0	138,647,731	55,564,546	

Instructions for Account 190

1. ADIT items related only to Non-Electric Operations (e.g., Gas, Water, Sewer) or Production are directly assigned to Column C
2. ADIT items related only to Transmission are directly assigned to Column D
3. ADIT items related to Plant and not in Columns C & D are included in Column E
4. ADIT items related to labor and not in Columns C & D are included in Column F

5. Deferred income taxes arise when items are included in taxable income in different periods than they are included in rates, therefore if the item giving rise to the ADIT is not included in the formula, the associated ADIT amount shall be excluded

6. Re: Form 1-F filer: Sum of subtotals for Accounts 282 and 283 should tie to Form No. 1-F, p.113.57.c

ATTACHMENT H-16A

Attachment 1 - Accumulated Deferred Income Taxes (ADIT) Worksheet - December 31,2008

A ADIT- 282	B Total	C Production Or Other Related	D Only Transmission Related	E Plant Related	F Labor Related	G Justification
AFC DEFERRED TAX - FUEL IN SERVICE	(109,851)	(109,851)				Represents the amount of amortization of AFC in service not allowable for tax.
AFC DEFERRED TAX - PLANT IN SERVICE	(5,876,628)	(4,384,545)	(1,492,083)			Represents the amount of amortization of AFC in service not allowable for tax.
AFC DEFERRED TAX - PLANT IN SERVICE	47,278			47,278		Represents the amount of amortization of AFC in service not allowable for tax.
BOOK CAPITALIZED INTEREST CWIP	(2,690,214)			(2,690,214)		Represents the unallowable amount of book interest.
CAP EXPENSE	(24,911,038)			(24,911,038)		Capitalized for books and current deduction for tax as repairs.
CASUALTY LOSS	(14,378,711)			(14,378,711)		Book varies in treatment; tax sec. 165 casualty loss for the decline in value (up to the adj. basis) and Sec 162 deduction for repairs to restore to pre-casualty condition.
COMPUTER SOFTWARE-CWIP	(2,409,042)	(2,409,042)				Represents the allowable "In house" deduction for tax.
COMPUTER SOFTWARE-TAX AMORT	(22,758,611)				(22,758,611)	Total tax amortization shown as a schedule M deduction and add back total book amortization.
COST OF REMOVAL	(163,478,133)	(147,751,537)	(15,726,596)			Represents the actual cost of removal allowable for tax over the accrued amount.
DECOMMISSIONING	(3,444,500)	(3,444,500)				Tax deduction for funding decomm trust and tax deferral of book income generated by trust.
DECOMMISSIONING	(277,905,325)	(277,905,325)				Tax deduction for funding decomm trust and tax deferral of book income generated by trust.
FERC FULL NORM CURR PROV - COOPS	157,564			157,564		Represents the difference between book and tax depreciation for FERC jurisdiction.
FERC FULL NORM CURR PROV - MS	(1,917,514)			(1,917,514)		Represents the difference between book and tax depreciation for FERC jurisdiction.
FERC FULL NORM CURR PROV - MUNIS	(779,120)			(779,120)		Represents the difference between book and tax depreciation for FERC jurisdiction.
FERC FULL NORM CURR PROV - ODEC OTHER	877,747			877,747		Represents the difference between book and tax depreciation for FERC jurisdiction.
FERC FULL NORM RES PROV - COOPS	(4,892,143)			(4,892,143)		Represents the difference between book and tax depreciation for FERC jurisdiction.
FERC FULL NORM RES PROV - MS	(11,495,095)			(11,495,095)		Represents the difference between book and tax depreciation for FERC jurisdiction.
FERC FULL NORM RES PROV - MUNIS	(5,043,293)			(5,043,293)		Represents the difference between book and tax depreciation for FERC jurisdiction.
FERC FULL NORM RES PROV - ODEC	(6,322,631)			(6,322,631)		Represents the difference between book and tax depreciation for FERC jurisdiction.
FERC FULL NORM RES PROV - ODEC NO. ANNA	748,516			748,516		Represents the difference between book and tax depreciation for FERC jurisdiction.
INVOLUNTARY CONVERSION - TELECOMMUNICATIONS	(1,104,045)	(1,104,045)				Represents the difference between book and tax related to the disposal of telecommunication equipment. Recognized for tax purposes when utilized.
LIBERALIZED DEPRECIATION - FUEL	(1,265,643)	(1,265,643)				Represents difference between book burn of nuclear fuel based on usage vs. tax depreciation.
LIBERALIZED DEPRECIATION - FUEL CWIP	(598,960)	(598,960)				Difference between book CWIP and Tax CWIP as a result of Euro exchange utilization.
LIBERALIZED DEPRECIATION - PLANT ACUFILE	(1,863,919,477)	(1,720,397,677)	(143,521,800)			Difference between book and tax depreciation taking in consideration flow-through and ARAM.
METERS	(1,447,190)	(1,447,190)				Books pre-capitalize when purchased ; tax purposes when installed.
REG ASSET - ASBESTOS	(85,434)	(85,434)				Amortized into expense for book purposes over the recovery period; capitalization of the cost for tax purposes.
FIXED ASSETS	(17,002,889)			(17,002,889)		Represents IRS audit adjustments to plant-related differences.
LIBERALIZED DEPRECIATION - PLANT ACUFILE FIN46	(13,635,207)	(13,635,207)				Represents the adjustment to FERC for FIN46 assets.
FAS 109 REG ASSET	(38,960,711)	(38,960,711)				Represents deferred tax deficiency related to previous flow-through and ARAM related ADIT that will be collected from t customers.
Subtotal - p275 (Form 1-F filer: see note 6 below)	(2,484,600,300)	(2,213,499,667)	(160,740,479)	(87,601,543)	(22,758,611)	
Less FASB 109 Above if not separately removed	0					
Less FASB 106 Above if not separately removed	0					
Total	(2,484,600,300)	(2,213,499,667)	(160,740,479)	(87,601,543)	(22,758,611)	

Instructions for Account 282

1. ADIT items related only to Non-Electric Operations (e.g., Gas, Water, Sewer) or Production are directly assigned to Column C
2. ADIT items related only to Transmission are directly assigned to Column D
3. ADIT items related to Plant and not in Columns C & D are included in Column E
4. ADIT items related to labor and not in Columns C & D are included in Column F

5. Deferred income taxes arise when items are included in taxable income in different periods than they are included in rates, therefore if the item giving rise to the ADIT is not included in the formula, the associated ADIT amount shall be excluded

6. Re: Form 1-F filer: Sum of subtotals for Accounts 282 and 283 should tie to Form No. 1-F, p.113.57.c

A ADIT-283	B Total	C Production Or Other Related	D Only Transmission Related	E Plant Related	F Labor Related	G Justification
FUEL HANDLING COSTS	(129,333)	(129,333)				IRS settlement required additional tax capitalization of handling costs.
EARNEST MONEY	(12,692)	(12,692)				Represents advances not recognized for tax.
GAIN(LOSS) INTERCO SALES -BOOK/TAX	(4,924,125)			(4,924,125)		Tax deferred recognition of intercompany gain/loss due to consolidated return rules.
GAIN(LOSS) INTERCO SALES -BOOK/TAX	(1,833,921)			(1,833,921)		Tax deferred recognition of intercompany gain/loss due to consolidated return rules.
REGULATORY ASSET - D & D	(216,946)	(216,946)				Represents cost that for regulatory purposes needs to be amortized over a prescribed life. However, allowable for t when incurred.
REGULATORY ASSET - FAS 112	(1,170,684)				(1,170,684)	Represents cost that for regulatory purposes needs to be amortized over a prescribed life. However, allowable for tax when incurred.
REGULATORY ASSET - ISABEL	(1,618,834)	(1,618,834)				Represents cost that for regulatory purposes needs to be amortized over a prescribed life. However, allowable for tax when incurred.
REGULATORY ASSET - NUG	(7,680,479)	(7,680,479)				Represents cost that for regulatory purposes needs to be amortized over a prescribed life. However, allowable for tax when incurred.
REGULATORY ASSET - PJM	(23,146,513)	(23,146,513)				Represents cost that for regulatory purposes needs to be amortized over a prescribed life. However, allowable for tax when incurred.
REGULATORY ASSET - VA SLS TAX	(3,959,885)	(3,959,885)				Represents cost that for regulatory purposes needs to be amortized over a prescribed life. However, allowable for t when incurred.
SO2 ALLOWANCES - NONCURRENT	(479,412)	(479,412)				Book expense for emissions allowances based on moving-average-cost, tax expense based on specific identification.
W.VA. STATE NOL CFWD	2,352,864		2,352,864			Represents the deferred state tax impact related to WV NOL. This deferral will turn around when the pollution control projects are placed in service
W.VA. STATE POLLUTION CONTROL	(23,482,458)	(23,482,458)				Represents the deferred state tax impact related to WV Pollution control projects. This deferral will turn around once placed in service.
FAS 109 REG ASSET	(25,129,573)	(25,129,573)				Represents tax gross-up on deferred tax deficiency related to previous flow-through and ARAM related ADIT.
	0					
Subtotal - p277 (Form 1-F filer: see note 6, below)	(91,431,991)	(85,856,125)	2,352,864	(6,758,046)	(1,170,684)	
Less FASB 109 Above if not separately removed	-					
Less FASB 106 Above if not separately removed	-				-	
Total	(91,431,991)	(85,856,125)	2,352,864	(6,758,046)	(1,170,684)	

Instructions for Account 283

1. ADIT items related only to Non-Electric Operations (e.g., Gas, Water, Sewer) or Production are directly assigned to Column C
2. ADIT items related only to Transmission are directly assigned to Column D
3. ADIT items related to Plant and not in Columns C & D are included in Column E
4. ADIT items related to labor and not in Columns C & D are included in Column F

5. Deferred income taxes arise when items are included in taxable income in different periods than they are included in rates, therefore if the item giving rise to the ADIT is not included in the formula, the associated ADIT amount shall be excluded

6. Re: Form 1-F filer: Sum of subtotals for Accounts 282 and 283 should tie to Form No. 1-F, p.113.57.c

ATTACHMENT H-16A

Attachment 1 - Accumulated Deferred Income Taxes (ADIT) Worksheet - December 31,2008

Attachment 1- Accumulated Deferred Income Taxes (ADIT) Workshee

Amortization ITC-255

		Item	Balance	Amortization
1	Amortization			3,272
2	Amortization to line 136 of Appendix A	Total		1,050
3	Total		-	4,322
4	Total Form No. 1 (p 266 & 267)	Form No. 1 balance (p.266) for amortization		4,322
5	Difference /1		-	-

/1 Difference must be zero

Virginia Electric and Power Company
ATTACHMENT H-16A
Attachment 1A - Accumulated Deferred Income Taxes (ADIT) Worksheet - December 31, 2007

	Only Transmission Related	Plant Related	Labor Related	Total ADIT
ADIT- 282	(157,080,388)	(77,801,543)	(22,758,611)	
ADIT-283	0	(4,405,182)	0	
ADIT-190	0	138,602,382	41,564,546	
Subtotal	(157,080,388)	56,395,657	18,805,935	
Wages & Salary Allocator			3.4890%	
Gross Plant Allocator		8.5694%		
ADIT	(157,080,388)	4,832,781	656,136	(151,591,470)

In filling out this attachment, a full and complete description of each item and justification for the allocation to Columns B-E and each separate ADIT item will be listed. Dissimilar items with amounts exceeding $100,000 will be listed separately.

A *ADIT-190*	B *Total*	C *Production Or Other Related*	D *Only Transmission Related*	E *Plant Related*	F *Labor Related*	G *Justification*
BAD DEBTS	4,837,795	4,837,795				For tax purposes bad debts are deductible when they are deemed to be uncollectible / worthless.
EPA AUCTION PROCEEDS	2,314,446	2,314,446				Book expense for emissions allowances based on moving-average-cost, tax expense based on specific identification.
FLEET LEASE CREDIT - CURRENT	58,719			58,719		Books amortizes the fleet lease extension credit over the new lease; tax takes the deduction when incurred
GROSS REC-UNBILLED REV-NC	90,408	90,408				Books include income when meter is read, tax when service is provided.
NUCLEAR FUEL - PERMANENT DISPOSAL	2,938	2,938			-	Books estimate expense, tax deduction taken when paid.
SEPARATION/ERT	60,427				60,427	Book amount accrued and expensed; tax deduction when paid.
SO2 ALLOWANCES - CURRENT	28,999	28,999			-	Book expense for emissions allowances based on moving-average-cost, tax expense based on specific identification.
SUCCESS SHARE PLAN	419,465				419,465	Book amount accrued as its earned; tax deduction is actual payout
VA PROPERTY TAX	3,131,384			3,131,384		Property tax expense is accrued for accounting purposes using the prior year's rates on the balance of the property located in the state at December 31 of the previous year. Tax takes a deduction when paid.
WEST VA PROPERTY TAX	2,323,235	2,323,235				Property tax expense is accrued for accounting purposes using the prior year's rates on the balance of the property located in the state at December 31 of the previous year. Tax takes a dedution when paid.
CAP EXPENSE	5,221,145			5,221,145		Represents 162 deduction for tax; capital for books.
CAPITALIZED INTEREST OPERATING CWIP	51,067,128	51,067,128				Represents tax capitalized interest on projects in CWIP - increase in taxable income.
CAPITALIZED INTEREST OPERATING IN SERVICE	(613,080)			(613,080)		Represents tax "In Service" Capitalized Interest placed in service net of tax amortization.
CAPITALIZED INTEREST OPERATING IN SERVICE	111,595,471			111,595,471		Represents tax "In Service" Capitalized Interest placed in service net of tax amortization.
DECOMMISSIONING & DECONTAMINATION	697,180	697,180				Book expensed as billed over 15 yr assessment period; tax deduct in year of assessment because all events test met as liability is based on prior facility use.
DECOMMISSIONING & DECONTAMINATION	929,573	929,573				Book expensed as billed over 15 yr assessment period; tax deduct in year of assessment because all events test met as liability is based on prior facility use.
DEFERRED GAIN/LOSS OPERATING	8,721,910			8,721,910		Represents the ADIT on Book Gain/Loss as accrued.
DSM	1,307,601	1,307,601				Represents a regulatory asset associated with Demand Side Mgt. Program that is being amortized for books.
EARNEST MONEY	12,692	12,692				Represents advances not recognized for tax.
FAS 143 ASSET OBLIGATION	10,215,580	10,215,580				Represents ARO accruals not deductible for tax.
FAS143 DECOMMISSIONING	278,219,843	278,219,843				Represents ARO accruals not deductible for tax.
FLEET LEASE CREDIT - NONCURRENT	213,571			213,571		Books amortizes the fleet lease extension credit over the new lease; tax takes the deduction when incurred.
GAIN(LOSS) INTERCO SALES -BOOK/TAX	4,747,884			4,747,884		Tax recognizes the intercompany gain/loss over the tax life of the assets.
GENERAL BUSINESS CREDITS	2,342,401			2,342,401		Represents business credits not expensed through current due to consolidated return limitations.
INT STOR NORTH ANNA	7,142,504	7,142,504				Books recognizes the expense as incurred. For tax the deduction is recognized when the casks are filled.
INT STOR SURRY	3,619,811	3,619,811				Books recognizes the expense as incurred. For tax the deduction is recognized when the casks are filled.
LONG TERM DISABILITY RESERVE	3,810,955				3,810,955	Book estimate accrued and expensed; tax deduction when paid.
METERS	3,272,689	3,272,689				Books pre-capitalize when purchased; tax purposes when installed.
OPEB	19,436,612				19,436,612	Represents the difference between the book accrual expense and the actual funded amount.
POWER PURCHASE BUYOUT	405,533	405,533				Represents the difference between the book accrual expense and the actual funded amount.
PREMIUM, DEBT, DISCOUNT AND EXPENSE	2,913,880			2,913,880		Books record the yield to maturity method ; taxes amortize staight line.
REACQUIRED DEBT GAIN(LOSS)	1,092,599			1,092,599		Amortized for books and expensed for tax purposes.
REACTOR DECOMMISSIONING LIABILITY	910,000	910,000				Represents the difference between the accrual and payments.
REGULATORY LIABILITY - FAS 143	4,592,488	4,592,488				Represents regulatory liability established due to adoption of FAS 143.
RETIREMENT - (FASB 87)	17,837,087				17,837,087	Book estimate accrued and expensed; tax deduction when paid.
W.VA. STATE NOL CFWD - FEDERAL EFFECT	(823,502)			(823,502)		Federal effect of state deductions.
W.VA. STATE POLLUTION CONTROL - FEDERAL EFFECT	8,218,858	8,218,858				Federal effect of state deductions.
FAS 109 ITC REG LIABILITY	13,793,283	13,793,283				Represents the tax effect of ITC that will be refunded to the customer.
Subtotal - p234	574,169,512	394,002,584	0	138,602,382	41,564,546	
Less FASB 109 Above if not separately removed	0		0			
Less FASB 106 Above if not separately removed	0		0		0	
Total	574,169,512	394,002,584	0	138,602,382	41,564,546	

Instructions for Account 190:

1. ADIT items related only to Non-Electric Operations (e.g., Gas, Water, Sewer) or Production are directly assigned to Column C
2. ADIT items related only to Transmission are directly assigned to Column D
3. ADIT items related to Plant and not in Columns C & D are included in Column E
4. ADIT items related to labor and not in Columns C & D are included in Column F
5. Deferred income taxes arise when items are included in taxable income in different periods than they are included in rates, therefore if the item giving rise to the ADIT is not included in the formula, the associated ADIT amount shall be excluded

6. Re: Form 1-F filer: Sum of subtotals for Accounts 282 and 283 should tie to Form No. 1-F, p.113.57.c

A *ADIT- 282*	B *Total*	C *Production Or Other Related*	D *Only Transmission Related*	E *Plant Related*	F *Labor Related*	G *Justification*
AFC DEFERRED TAX - FUEL IN SERVICE	(109,851)	(109,851)				Represents the amount of amortization of AFC in service not allowable for tax.
AFC DEFERRED TAX - PLANT IN SERVICE	(5,876,628)	(4,384,545)	(1,492,083)			Represents the amount of amortization of AFC in service not allowable for tax.
AFC DEFERRED TAX - PLANT IN SERVICE	47,278			47,278		Represents the amount of amortization of AFC in service not allowable for tax.
BOOK CAPITALIZED INTEREST CWIP	(2,690,214)			(2,690,214)		Represents the unallowable amount of book interest.
CAP EXPENSE	(15,111,038)			(15,111,038)		Capitalized for books and current deduction for tax as repairs.
CASUALTY LOSS	(14,378,711)			(14,378,711)		Book varies in treatment; tax sec. 165 casualty loss for the decline in value (up to the adj. basis) and Sec 162 deduction for repairs to restore to pre-casualty condition.
COMPUTER SOFTWARE-CWIP	(2,409,042)	(2,409,042)				Represents the allowable "In house" deduction for tax.
COMPUTER SOFTWARE-TAX AMORT	(22,758,611)				(22,758,611)	Total tax amortization shown as a schedule M deduction and add back total book amortization.
COST OF REMOVAL	(156,548,133)	(141,488,203)	(15,059,930)			Represents the actual cost of removal allowable for tax over the accrued amount.
DECOMMISSIONING	(3,444,500)	(3,444,500)				Tax deduction for funding decomm trust and tax deferral of book income generated by trust.
DECOMMISSIONING	(277,905,325)	(277,905,325)				Tax deduction for funding decomm trust and tax deferral of book income generated by trust.
FERC FULL NORM CURR PROV - COOPS	157,564			157,564		Represents the difference between book and tax depreciation for FERC jurisdiction.
FERC FULL NORM CURR PROV - MS	(1,917,514)			(1,917,514)		Represents the difference between book and tax depreciation for FERC jurisdiction.
FERC FULL NORM CURR PROV - MUNIS	(779,120)			(779,120)		Represents the difference between book and tax depreciation for FERC jurisdiction.
FERC FULL NORM CURR PROV - ODEC OTHER	877,747			877,747		Represents the difference between book and tax depreciation for FERC jurisdiction.
FERC FULL NORM RES PROV - COOPS	(4,892,143)			(4,892,143)		Represents the difference between book and tax depreciation for FERC jurisdiction.
FERC FULL NORM RES PROV - MS	(11,495,095)			(11,495,095)		Represents the difference between book and tax depreciation for FERC jurisdiction.
FERC FULL NORM RES PROV - MUNIS	(5,043,293)			(5,043,293)		Represents the difference between book and tax depreciation for FERC jurisdiction.
FERC FULL NORM RES PROV - ODEC	(6,322,631)			(6,322,631)		Represents the difference between book and tax depreciation for FERC jurisdiction.
FERC FULL NORM RES PROV - ODEC NO. ANNA	748,516			748,516		Represents the difference between book and tax depreciation for FERC jurisdiction.
INVOLUNTARY CONVERSION - TELECOMMUNICATIONS	(1,104,045)	(1,104,045)				Represents the difference between book and tax related to the disposal of telecommunication equipment. Recognized for tax purposes when utilized.
LIBERALIZED DEPRECIATION - FUEL	(1,265,643)	(1,265,643)				Represents difference between book burn of nuclear fuel based on usage vs. tax depreciation.
LIBERALIZED DEPRECIATION - FUEL CWIP	(598,960)	(598,960)				Difference between book CWIP and Tax CWIP as a result of Euro exchange utilization.
LIBERALIZED DEPRECIATION - PLANT ACUFILE	(1,825,043,822)	(1,684,515,448)	(140,528,374)			Difference between book and tax depreciation taking in consideration flow-through and ARAM.
METERS	(1,447,190)	(1,447,190)				Books pre-capitalize when purchased ; tax purposes when installed.
REG ASSET - ASBESTOS	(85,434)	(85,434)				Amortized into expense for book purposes over the recovery period; capitalization of the cost for tax purposes.
FIXED ASSETS	(17,002,889)			(17,002,889)		Represents IRS audit adjustments to plant-related differences.
LIBERALIZED DEPRECIATION - PLANT ACUFILE FIN46	(13,635,207)	(13,635,207)				Represents the adjustment to FERC for FIN46 assets.
FAS 109 REG ASSET	(38,455,570)	(38,455,570)				Represents deferred tax deficiency related to previous flow- through and ARAM-related ADIT that will be collected from the customers.
Subtotal - p275 (Form 1-F filer: see note 6 below)	(2,428,489,504)	(2,170,848,962)	(157,080,388)	(77,801,543)	(22,758,611)	
Less FASB 109 Above if not separately removed						
Less FASB 106 Above if not separately removed						
Total	(2,428,489,504)	(2,170,848,962)	(157,080,388)	(77,801,543)	(22,758,611)	

Instructions for Account 282:
1. ADIT items related only to Non-Electric Operations (e.g., Gas, Water, Sewer) or Production are directly assigned to Column C
2. ADIT items related only to Transmission are directly assigned to Column D
3. ADIT items related to Plant and not in Columns C & D are included in Column E
4. ADIT items related to labor and not in Columns C & D are included in Column F
5. Deferred income taxes arise when items are included in taxable income in different periods than they are included in rates, therefore if the item giving rise to the ADIT is not included in the formula, the associated ADIT amount shall be excluded

6. Re: Form 1-F filer: Sum of subtotals for Accounts 282 and 283 should tie to Form No. 1-F, p.113.57.c

ATTACHMENT H-16A

Attachment 1A - Accumulated Deferred Income Taxes (ADIT) Worksheet - December 31, 2007

A	B	C	D	E	F	G
ADIT-283	*Total*	*Production Or Other Related*	*Only Transmission Related*	*Plant Related*	*Labor Related*	*Justification*
FUEL HANDLING COSTS	(129,333)	(129,333)				IRS settlement required additional tax capitalization of handling costs.
EARNEST MONEY	(12,692)	(12,692)				Represents advances not recognized for tax.
GAIN(LOSS) INTERCO SALES -BOOK/TAX	(4,924,125)			(4,924,125)		Tax deferred recognition of intercompany gain/loss due to consolidated return rules.
GAIN(LOSS) INTERCO SALES -BOOK/TAX	(1,833,921)			(1,833,921)		Tax deferred recognition of intercompany gain/loss due to consolidated return rules.
REGULATORY ASSET - D & D	(216,946)	(216,946)				Represents cost that for regulatory purposes needs to be amortized over a prescribed life. However, allowable for tax when incurred.
REGULATORY ASSET - FAS 112	(1,170,684)	(1,170,684)				Represents cost that for regulatory purposes needs to be amortized over a prescribed life. However, allowable for tax when incurred.
REGULATORY ASSET - ISABEL	(1,618,834)	(1,618,834)				Represents cost that for regulatory purposes needs to be amortized over a prescribed life. However, allowable for tax when incurred.
REGULATORY ASSET - NUG	(7,680,479)	(7,680,479)				Represents cost that for regulatory purposes needs to be amortized over a prescribed life. However, allowable for tax when incurred.
REGULATORY ASSET - PJM	(23,146,513)	(23,146,513)				Represents cost that for regulatory purposes needs to be amortized over a prescribed life. However, allowable for tax when incurred.
REGULATORY ASSET - VA SLS TAX	(3,959,885)	(3,959,885)				Represents cost that for regulatory purposes needs to be amortized over a prescribed life. However, allowable for tax when incurred.
SO2 ALLOWANCES - NONCURRENT	(479,412)	(479,412)				Book expense for emissions allowances based on moving-average-cost, tax expense based on specific identification.
W.VA. STATE NOL CFWD	2,352,864			2,352,864		Represents the deferred state tax impact related to WV NOL. This deferral will turn around when the pollution control projects are placed in service.
W.VA. STATE POLLUTION CONTROL	(23,482,458)	(23,482,458)				Represents the deferred state tax impact related to WV Pollution control projects. This deferral will turn around once placed in service.
FAS 109 REG ASSET	(24,805,973)	(24,805,973)				Represents tax gross-up on deferred tax deficiency related to previous flow-through and ARAM-related ADIT.
	0					
Subtotal - p277 (Form 1-F filer: see note 6, below)	(91,108,391)	(86,703,209)	-	(4,405,182)	-	
Less FASB 109 Above if not separately removed						
Less FASB 106 Above if not separately removed					-	
Total	(91,108,391)	(86,703,209)	-	(4,405,182)	-	

Instructions for Account 283:
1. ADIT items related only to Non-Electric Operations (e.g., Gas, Water, Sewer) or Production are directly assigned to Column C
2. ADIT items related only to Transmission are directly assigned to Column D
3. ADIT items related to Plant and not in Columns C & D are included in Column E
4. ADIT items related to labor and not in Columns C & D are included in Column F
5. Deferred income taxes arise when items are included in taxable income in different periods than they are included in rates, therefore if the item giving rise to the ADIT is not included in the formula, the associated ADIT amount shall be excluded

6. Re: Form 1-F filer: Sum of subtotals for Accounts 282 and 283 should tie to Form No. 1-F, p.113.57.c

Virginia Electric and Power Company
ATTACHMENT H-16A
Attachment 2 - Taxes Other Than Income Worksheet
2008 (000's)

	Other Taxes		Page 263 Col (i)	Allocator		Allocated Amount
	Plant Related			***Gross Plant Allocator***		
1	Transmission Personal Property Tax (directly assigned to Transmission)	$	8,570	100.0000%	$	8,570
1a	Other Plant Related Taxes		0	8.5694%		-
2						-
3						-
4						-
5						-
						-
	Total Plant Related	$	8,570		$	8,570
	Labor Related			***Wages & Salary Allocator***		
6	Federal FICA & Unemployment & State Unemployment	$	41,313			
	Total Labor Related	$	41,313	3.4890%	$	1,441
	Other Included			***Gross Plant Allocator***		
7	Sales and Use Tax	$	2,368			
	Total Other Included	$	2,368	8.5694%	$	203
	Total Included				$	10,215
	Currently Excluded					
8	Business and Occupation Tax - West Virginia	$	19,608			
9	Gross Receipts Tax		9,832			
10	IFTA Fuel Tax		6			
11	Property Taxes - Other		96,622			
12			0			
13			0			
14			0			
15			0			
16			0			
17			0			
18			0			
19			0			
20			0			
21	Total "Other" Taxes (included on p. 263)	$	126,068			
22	Total "Taxes Other Than Income Taxes" - acct 408.10 (p. 114.14)	$	178,319			
23	Difference	$	(52,251)			

Criteria for Allocation:

A Other taxes that are incurred through ownership of plant including transmission plant will be either directly assigned or allocated based on the Gross Plant Allocator. If the taxes are 100% recovered at retail they will not be included.

B Other taxes that are incurred through ownership of only general or intangible plant will be allocated based on the Wages and Salary Allocator. If the taxes are 100% recovered at retail they will not be included.

C Other taxes that are assessed based on labor will be allocated based on the Wages and Salary Allocator.

D Other taxes except as provided for in A, B and C above, that are incurred and (1) are not fully recovered at retail or (2) are directly or indirectly related to transmission service will be allocated based on the Gross Plant Allocator; provided, however, that overheads shall be treated as in footnote B above.

VEPCO
ATTACHMENT H-16A
Attachment 2A - Direct Assignment of Property Taxes Per Function
2008 (000's)

Directly Assigned Property Taxes	$	105,192
Production Property Tax		52,427
Transmission Property Tax		8,510
Distribution Property tax		42,530
General Property Tax		1,725
Total check		105,192

Allocation of General Property Tax to Transmission

General Property Tax	$	1,725.00
Wages & Salary Allocator		3.4890%
Trans General		60

Total Transmission Property Taxes		
Transmission	$	8,510
General		60
Total Transmission Property Taxes	$	8,570

Virginia Electric and Power Company
ATTACHMENT H-16A
Attachment 3 - Revenue Credit Workpaper
2008 (000's)

			Transmission Related	Production/Other Related	Total
	Account 454 - Rent from Electric Property				
1	Rent from Electric Property - Transmission Related (Note 3)		6,200	-	6,200
2	Total Rent Revenues	(Sum Lines 1)	6,200	-	6,200
	Account 456 - Other Electric Revenues (Note 1)				
3	Schedule 1A				
4	Net revenues associated with Network Integration Transmission Service (NITS) and for the transmission component of the NCEMPA contract rate for which the load is not included in the divisor. (Note 4)		2,000	0	2,000
5	Point to Point Service revenues received by Transmission Owner for which the load is not included in the divisor (Note 4)		-	0	-
6	PJM Transitional Revenue Neutrality (Note 1)		-	0	-
7	PJM Transitional Market Expansion (Note 1)		-	0	-
8	Professional Services (Note 3)		8,676	0	8,676
9	Revenues from Directly Assigned Transmission Facility Charges (Note 2)		3,470	0	3,470
10	Rent or Attachment Fees associated with Transmission Facilities (Note 3)		-	0	-
11	Gross Revenue Credits (Accounts 454 and 456)	(Sum Lines 2-10)	20,346	-	20,346
12	Less line 14g		(10,976)	-	(10,976)
13	Total Revenue Credits		9,370	-	9,370
	Revenue Adjustment to Determine Revenue Credit				
14a	Revenues included in lines 1-11 which are subject to 50/50 sharing. (Lines 1 + 8 + 10)		14,876	-	14,876
14b	Costs associated with revenues in line 14a		7,076	-	7,076
14c	Net Revenues (14a - 14b)		7,800	-	7,800
14d	50% Share of Net Revenues (14c / 2)		3,900	-	3,900
14e	Cost associated with revenues in line 14b that are included in FERC accounts recovered through the formula times the allocator used to functionalize the amounts in the FERC account to the transmission service at issue		-	-	-
14f	Net Revenue Credit (14d + 14e)		3,900	-	3,900
14g	Line 14f less line 14a		(10,976)	-	(10,976)

Revenue Adjustment to Determine Revenue Credit

Note 1: All revenues related to transmission that are received as a transmission owner (*i.e.*, not received as a LSE), for which the cost of the service is recovered under this formula, except as specifically provided for elsewhere in this Attachment or elsewhere in the formula will be included as a revenue credit or included in the peak on line 169 of Appendix A.

Note 2: If the costs associated with the Directly Assigned Transmission Facility Charges are included in the Rates, the associated revenues are included in the Rates. If the costs associated with the Directly Assigned Transmission Facility Charges are not included in the Rates, the associated revenues are not included in the Rates.

Note 3: Ratemaking treatment for the following specified secondary uses of transmission assets: (1) right-of-way leases and leases for space on transmission facilities for telecommunications; (2) transmission tower licenses for wireless antennas; (3) right-of-way property leases for farming, grazing or nurseries; (4) licenses of intellectual property (including a portable oil degasification process and scheduling software); and (5) transmission maintenance and consulting services (including energized circuit maintenance, high-voltage substation maintenance, safety training, transformer oil testing, and circuit breaker testing) to other utilities and large customers (collectively, products). VEPCO will retain 50% of net revenues consistent with *Pacific Gas and Electric Company*, 90 FERC ¶ 61,314. In order to use lines 14a - 14g, the utility must track in separate subaccounts the revenues and costs associated with each secondary use (except for the cost of the associated income taxes).

Note 4: Revenues from Schedule 12 are not included in the total above to the extent they are credited under Schedule 12. In addition, revenues from Schedule 7, Schedule 8 and H-A are not included in the total above to the extent PJM credits VEPCO's share of these revenues monthly to network customers under Attachment H-16.

Virginia Electric and Power Company
ATTACHMENT H-16A
Attachment 4 - Calculation of 100 Basis Point Increase in ROE
2008 (000's)

	Return and Taxes with Basis Point increase in ROE				
A	Basis Point increase in ROE and Income Taxes			(Line 130 + 140)	128,862
B	100 Basis Point increase in ROE	(Note J from Appendix A)		Fixed	1.00%
Return Calculation					
Line Ref.					
62	Rate Base			(Line 44 + 61)	942,201
	Long Term Interest				
104	**Long Term Interest**			p117.62c through 67c	271,886
105	Less LTD Interest on Securitization Bonds	(Note P)		Attachment 8	0
106	Long Term Interest			(Line 104 - 105)	271,886
107	Preferred Dividends		enter positive	p118.29c	15,721
	Common Stock				
108	Proprietary Capital			p112.16c,d/2	5,588,155
109	Less Preferred Stock		enter negative	(Line 117)	-259,014
110	Less Account 219 - Accumulated Other Comprehensive Income		enter negative	p112.15c,d/2	-122,504
111	Common Stock			(Sum Lines 108 to 110)	5,206,637
	Capitalization				
112	Long Term Debt			p112.24c,d/2	4,326,482
113	Less Loss on Reacquired Debt		enter negative	p111.81c,d/2	-1,516
114	Plus Gain on Reacquired Debt		enter positive	p113.61c,d/2	0
115	Less LTD on Securitization Bonds		enter negative	Attachment 8	0
116	Total Long Term Debt			(Sum Lines 112 to 115)	4,324,966
117	Preferred Stock			p112.3c,d/2	259,014
118	Common Stock			(Line 111)	5,206,637
119	Total Capitalization			(Sum Lines 116 to 118)	9,790,617
120	Debt %		Total Long Term Debt	(Line 116 / 119)	44.2%
121	Preferred %		Preferred Stock	(Line 117 / 119)	2.6%
122	Common %		Common Stock	(Line 118 / 119)	53.2%
123	Debt Cost		Total Long Term Debt	(Line 106 / 116)	0.0629
124	Preferred Cost		Preferred Stock	(Line 107 / 117)	0.0607
125	Common Cost		Common Stock	Appendix A Line 125 + 100 Basis Points	0.1240
126	Weighted Cost of Debt		Total Long Term Debt (WCLTD)	(Line 120 * 123)	0.0278
127	Weighted Cost of Preferred		Preferred Stock	(Line 121 * 124)	0.0016
128	Weighted Cost of Common		Common Stock	(Line 122 * 125)	0.0659
129	Total Return (R)			**(Sum Lines 126 to 128)**	**0.0953**
130	Investment Return = Rate Base * Rate of Return			**(Line 62 * 129)**	**89,809**
Composite Income Taxes					
	Income Tax Rates				
131	FIT=Federal Income Tax Rate				0.3500
132	SIT=State Income Tax Rate or Composite				0.0623
133	p = percent of federal income tax deductible for state purposes			Per State Tax Code	0.0000
134	T	T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =			0.3905
135	T/ (1-T)				0.6407
	ITC Adjustment				
136	Amortized Investment Tax Credit		enter negative	Attachment 1	-1,050
137	T/(1-T)			(Line 135)	0.6407
138	**ITC Adjustment Allocated to Transmission**		(Note I from Appendix A)	(Line 136 * (1 + 137))	**-1,723**
139	**Income Tax Component =**	CIT=(T/1-T) * Investment Return * (1-(WCLTD/R)) =			40,775
140	**Total Income Taxes**			**(Line 138 + 139)**	**39,053**

Electric / Non-electric Cost Support

Line #s	Descriptions	Notes	Page #'s & Instructions	Previous Year Form 1Dec	Current Year Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Form 1 Dec	Average	Non-electric Portion	Details
	Plant Allocation Factors																		
8	Electric Plant in Service	(Notes A & Q)	p207.104g/Plant-Acc. Deprc Wks	21,767,839	21,849,234	21,947,712	22,062,019	22,178,183	22,269,737	22,579,640	22,645,913	22,716,701	22,792,617	22,876,348	22,912,751	22,935,267	22,425,689	0	
15	Accumulated Depreciation (Total Electric Plant)	(Notes A & Q)	p219.29c	8,875,387	8,924,892	8,981,090	9,038,150	9,087,582	9,143,762	9,201,906	9,245,514	9,294,848	9,342,510	9,385,128	9,434,818	9,485,200	9,187,753	0	
12	Accumulated Intangible Amortization	(Notes A & Q)	p200.21c	180,407	180,407	180,407	180,407	180,407	180,407	180,407	180,407	180,407	180,407	180,407	180,407	180,407	180,407	0	Respondent is Electric Utility only.
13	Accumulated Common Amortization - Electric	(Notes A & Q)	p356	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0	
14	Accumulated Common Plant Depreciation - Electric	(Notes A & Q)	p356	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0	
	Plant In Service																		
21	Transmission Plant in Service	(Notes A & Q)	p207.58.g/Trans.Input Sht	1,892,971	1,892,971	1,892,971	1,897,213	1,898,804	1,913,784	1,920,545	2,036,941	2,037,074	2,037,207	2,037,340	2,037,340	2,054,972	1,965,395	0	
15	Generator Step-Ups		Trans. Input Sht	75,343	75,343	75,343	75,343	75,343	75,343	75,343	75,343	75,343	75,343	75,343	75,343	75,343	75,343	0	
23	Generator Interconnect Facilities		Input Sht	-	-	-	-	-	-	-	-	-	-	-	-	-	-		
25	General & Intangible		p205.5.g & p207.99.g/G&I Wksht	896,607	899,820	901,291	902,743	904,786	906,320	908,337	909,982	912,007	913,555	915,859	918,316	921,782	908,570	0	
26	Common Plant (Electric Only)	(Notes A & Q)	p356	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0	
	Accumulated Depreciation																		
32	Transmission Accumulated Depreciation	(Notes A & Q)	p219.25.c/Trans.Input Sht	805,276	808,453	811,629	814,806	817,990	821,177	824,391	827,616	831,051	834,485	837,920	841,355	844,790	824,688	0	
33	Transmission Accumulated Depreciation - Generator Step-Ups		GSU Input Sht	1,472	1,594	1,715	1,837	1,959	2,080	2,202	2,323	2,445	2,567	2,688	2,810	2,932	2,202	0	
34	Transmission Accumulated Depreciation - Interconnection Facilities		Input Sht	-	-	-	-	-	-	-	-	-	-	-	-	-	-		
36	Accumulated General Depreciation	(Notes A & Q)	p219.28.b	349,537	354,628	359,739	364,870	370,023	375,198	380,395	385,916	390,855	396,118	401,405	406,716	412,055	380,573	0	
	Materials and Supplies																		
50	Undistributed Stores Exp	(Notes A & R)	p227.6c & 16.c	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0	Respondent is Electric Utility only.
	Allocated General & Common Expenses																		
68	Common Plant O&M	(Note A)	p356	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0	
	Depreciation Expense																Electric		
86	Depreciation-Transmission	(Note A)	p336.7.b&c														38,158	0	
91	Depreciation-General	(Note A)															29,527	0	
92	Depreciation-Intangible	(Note A)	p336.1d&e/Attachment 5														32,992	0	Respondent is Electric Utility only.
87	Depreciation - Generator Step-Ups																1,501	0	
88	Depreciation - Interconnection Facilities																0	0	
96	Common Depreciation - Electric Only	(Note A)	p336.11.b														0	0	
97	Common Amortization - Electric Only	(Note A)	p356 or p336.11d														0	0	

O&M Expenses

Line #s	Descriptions	Notes	Page #'s & Instructions	Previous Year Form 1Dec	Current Year Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Form 1 Dec	Totals	Non-electric Portion	Details
63	Transmission O&M	(Note A)	p321.112.b/Trans. Input Sht	-	3,123	2,865	2,991	2,919	2,907	2,952	3,039	3,079	3,032	3,100	3,086	4,651	37,744	0	
64	Generator Step-Ups		Input Sheet														216	0	
65	Transmission by Others		p321.96.b	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0	

Wages & Salary

Line #s	Descriptions	Notes	Page #'s & Instructions	Previous Year Form 1Dec	Current Year Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Form 1 Dec	Totals	Non-electric Portion	Details
4	Total Wage Expense	(Note A)	p354.28b/Trans. Wksht														554,521	0	
5	Total A&G Wages Expense	(Note A)	p354.27b/Trans. Wksht														126,603	0	
1	Transmission Wages	(Note A)	p354.21b/Trans. Wksht														15,066	0	
2	Generator Step-Ups		Trans. Wksht														136	0	

Transmission / Non-transmission Cost Support

Line #s	Descriptions	Notes	Page #'s & Instructions	Previous Year Form 1Dec	Current Year Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Form 1 Dec	Average	Non-transmission Related	Details
30	Plant Held for Future Use (Including Land)	(Notes C & Q)	p214.47.d	5,338	5,338	5,338	5,338	5,338	5,338	5,338	5,338	5,338	5,338	5,338	5,338	5,338	5338	1,775	Specific identification based on plant records: The following plant investments are included:
																Form 1 Amount	Transmission Related	Non-transmission Related	
																5,338	3563	1,775	Enter Details

EPRI Dues Cost Support

Line #s	Descriptions	Notes	Page #'s & Instructions	Form 1 Amount	EPRI Dues	Details
	Allocated General & Common Expenses					
73	Less EPRI Dues	(Note D)	p352-353/Attachment 5	4055	4055	See Form 1

Regulatory Expense Related to Transmission Cost Support

Line #s	Descriptions	Notes	Page #'s & Instructions	Form 1 Amount	Transmission Related	Non-transmission Related	Details
	Allocated General & Common Expenses						
71	Less Regulatory Commission Exp Account 928	(Note E)	p323.189b/Attachment 5	$ 24,106	164	23,942	See FERC Form 1 pages 350-351.
	Directly Assigned A&G						
77	Regulatory Commission Exp Account 928	(Note G)	p323.189b/Attachment 5		164		Transmission related - Includes three year amortization of cost of current case.

Safety Related Advertising Cost Support

Line #s	Descriptions	Notes	Page #'s & Instructions	Form 1 Amount	Safety Related	Non-safety Related	Details
	Directly Assigned A&G						
81	General Advertising Exp Account 930.1	(Note F)	Attachment 5	2,629	-	2,629	

MultiState Workpaper

Line #s	Descriptions	Notes	Page #'s & Instructions	State 1	State 2	State 3	State 4	State 5	Details
	Income Tax Rates								
				Va	NC	Wva			Enter Calculation
132	SIT=State Income Tax Rate or Composite	(Note I)		5.59%	0.380%	0.26%			6.23%

Education and Out Reach Cost Support

Line #s	Descriptions	Notes	Page #'s & Instructions	Form 1 Amount	Education & Outreach	Other	Details
	Directly Assigned A&G						
78	General Advertising Exp Account 930.1	(Note K)	p323.191b	2,629	0	2,629	

Excluded Plant Cost Support

Line #s	Descriptions	Notes	Page #'s & Instructions		0	Description of the Facilities
	Adjustment to Remove Revenue Requirements Associated with Excluded Transmission Facilities			Includes only the costs of any Interconnection Facilities constructed for VEPCO's own Generating Facilities after March 15, 2000 in accordance with Order 2003.	0	General Description of the Facilities
						None
						Add more lines if necessary

Instructions:

1 Remove all investment below 69 kV or generator step up transformers included in transmission plant in service that are not a result of the RTEP Process

2 If unable to determine the investment below 69kV in a substation with investment of 69 kV and higher as well as below 69 kV, the following formula will be used:

		Example
A	Total investment in substation	1,000,000
B	Identifiable investment in Transmission (provide workpapers)	500,000
C	Identifiable investment in Distribution (provide workpapers)	400,000
D	Amount to be excluded (A x (C / (B + C)))	444,444

Transmission Related Account 242 Reserves

Line #s	Descriptions	Notes	Page #'s & Instructions	Beginning Year Balance	End of Year Balance	Average Balance	Allocation	Transmission Related		Details
47	Transmission Related Account 242 Reserves (exclude current year environmental site related reserves)			Enter $	Enter $			Amount		
	Directly Assignable to Transmission			$ -	$ -	$ -	100%	-		
	Labor Related, General plant related or Common Plant related			$ 6,087	$ 7,797	$ 6,942	3.489%	272		
	Plant Related						8.57%	-		
	Other			$ 297	$ 1,532	$ 915	0.00%	-		
	Total Transmission Related Reserves			$ -	$ -	$ -		272	To line 49	

Prepayments

Line #s	Descriptions	Notes	Page #'s & Instructions	Beginning Year Balance	End of Year Balance	Average Balance		To Line 50	Description of the Prepayments
48	Prepayments								
	Wages & Salary Allocator						3.489%		
	Pension Liabilities, if any, in Account 242			$ -	$ -	$ -	3.489%	-	
				$ -	$ -	$ -			
	Prepayments			$ 132,791	$ 14,787	$ 73,789	3.489%	2,574	
	Prepaid Pensions if not included in Prepayments			$ 1	$ 3	$ 2	3.489%	0	

Outstanding Network Credits Cost Support

Line #s	Descriptions	Notes	Page #'s & Instructions	Beginning Year Balance	End of Year Balance	Average Balance	Description of the Credits
	Network Credits						General Description of the Credits
58	Outstanding Network Credits	(Note N)	From PJM	$ -	$ -	$ -	None
59	Less Accumulated Depreciation Associated with Facilities with Outstanding Network Credits	(Note N)	From PJM	$ -	$ -	$ -	Add more lines if necessary

Extraordinary Property Loss

Line #s	Descriptions	Notes	Page #'s & Instructions	Amount	# of Years	Amortization	W/ interest	Amount	Number of years	Amortization
								$ -		
89									5	$ -

Interest on Outstanding Network Credits Cost Support

Line #s	Descriptions	Notes	Page #'s & Instructions	0	Description of the Interest on the Credits
				0	General Description of the Credits
				Enter $	None
					Add more lines if necessary

Facility Credits under Section 30.9 of the PJM OATT.

Line #s	Descriptions	Notes	Page #'s & Instructions	Amount	Description & PJM Documentation
	Revenue Requirement				
165	Facility Credits under Section 30.9 of the PJM OATT.			-	

PJM Load Cost Support

Line #s	Descriptions	Notes	Page #'s & Instructions	1 CP Peak	Description & PJM Documentation
	Network Zonal Service Rate			Enter	
169	1 CP Peak	(Note L)	PJM Data	19,688	

A&G Expenses - Other Post Employment Benefits

Line #s	Descriptions	Notes	Page #'s & Instructions	Amount
	Total A&G Expenses		p323.197b	339,538
	Less OPEB Current Year			13,458
	Plus: Stated OPEB (2008 actual)		Fixed (2008 actual)	13,458
69	Current Year Total A&G Expenses			339,538

Virginia Electric and Power Company
ATTACHMENT H-16A
Attachment 6 - True-up Adjustment for Network Integration Transmission Service

The True-Up Adjustment component of the Formula Rate for each Rate Year beginning with 2010 shall be determined as follows: [1]

(i) Beginning with 2009, no later than June 15 of each year VEPCO shall recalculate an adjusted Annual Transmission Revenue Requirement for the previous calendar year based on its actual costs as reflected in its Form No. 1 and its books and records for that calendar year, consistent with FERC accounting policies. [2]

(ii) VEPCO shall determine the difference between the recalculated Annual Transmission Revenue Requirement as determined in paragraph (i) above, and ATRR based on projected costs for the previous calendar year (True-Up Adjustment Before Interest).

(iii) The True-Up Adjustment shall be determined as follows:

True-Up Adjustment equals the True-Up Adjustment Before Interest multiplied by (1+i)^24 months

Where: i = Sum of (the monthly rates for the 7 months ending July 31 of the current year and the monthly rates for the 12 months ending December 31 of the preceding year) divided by 19 months. 0.000%

Each monthly rate used to calculate i shall be calculated pursuant to the Commission's regulations at 18 C.F.R. § 35.19a.

Summary of Formula Rate Process including True-Up Adjustment

Month	Year	Action
Fall	2007	TO populates the formula with Year 2008 estimated data
Sept	2008	TO populates the formula with Year 2009 estimated data
June	2009	TO populates the formula with Year 2008 actual data and calculates the 2008 True-Up Adjustment Before Interest
Sept	2009	TO calculates the Interest to include in the 2008 True-Up Adjustment
Sept	2009	TO populates the formula with Year 2010 estimated data and 2008 True-Up Adjustment
June	2010	TO populates the formula with Year 2009 actual data and calculates the 2009 True-Up Adjustment Before Interest
Sept	2010	TO calculates the Interest to include in the 2009 True-Up Adjustment
Sept	2010	TO populates the formula with Year 2011 estimated data and 2009 True-Up Adjustment
June	(Year)	TO populates the formula with (Year -1) actual data and calculates the (Year-1) True-Up Adjustment Before Interest
Sept	(Year)	TO calculates the Interest to include in the (Year-1) True-Up Adjustment
Sept	(Year)	TO populates the formula with (Year +1) estimated data and (Year-1) True-Up Adjustment

1 No True-Up Adjustment will be included in the Annual Transmission Revenue Requirement for 2008 or 2009 since the Formula Rate was not in effect for 2006 or 2007.

2 To the extent possible each input to the Formula Rate used to calculate the actual Annual Transmission Revenue Requirement included in the True-Up Adjustment either will be taken directly from the FERC Form No. 1 or will be reconcilable to the FERC Form No. 1 by the application of clearly identified and supported information. If the reconciliation is provided through a worksheet included in the filed Formula Rate template, the inputs to the worksheet must meet this transparency standard, and doing so will satisfy this transparency requirement for the amounts that are output from the worksheet and input to the main body of the Formula Rate.

Calendar Year Do for Each Calendar Year beginning in 2009

A	ATRR based on actual costs included for the previous calendar year but excludes the true-up adjustment.	-
B	ATRR based on projected costs included for the previous calendar year but excludes the true-up adjustment.	-
C	Difference (A-B)	-
D	Future Value Factor (1+i)^24	1.00000
E	True-up Adjustment (C*D)	0

Where:
i = interest rate as described in (iii) above.

Virginia Electric and Power Company
ATTACHMENT H-16A
Attachment 6A - True-up Adjustment for Annual Revenue Requirements recovered under Schedule 12

The True-Up Adjustment component of the annual revenue requirement for each project included in Attachment 7 for each Rate Year beginning with 2010 shall be determined as follows:[1]

(i) Beginning with 2009, no later than June 15 of each year VEPCO shall recalculate an adjusted Annual Revenue Requirement for the previous calendar year based on its actual costs as reflected in its Form No. 1 and its books and records for that calendar year, consistent with FERC accounting policies.[2]

(ii) VEPCO shall determine the difference between the recalculated Annual Revenue Requirement and the Annual Revenue Requirement based on its projections (True-Up Adjustment Before Interest).

(iii) The True-Up Adjustment for each project shall be determined as follows:

True-Up Adjustment equals the True-Up Adjustment Before Interest multiplied by (1+i)^24 months

Where: i = Sum of (the monthly rates for the 7 months ending July 31 of the current year and the monthly rates for the 12 months ending December 31 of the proceeding year) divided by 19 months.

Each monthly rate used to calculate i shall be calculated pursuant to the Commission's regulations at 18 C.F.R. § 35.19a.

Summary of Formula Rate Process including True-Up Adjustment

Month	Year	Action
Fall	2007	TO populates the formula with Year 2008 estimated data
Sept	2008	TO populates the formula with Year 2009 estimated data
June	2009	TO populates the formula with Year 2008 actual data and calculates the 2008 True-Up Adjustment Before Interest
Sept	2009	TO calculates the Interest to include in the 2008 True-Up Adjustment
Sept	2009	TO populates the formula with Year 2010 estimated data and 2008 True-Up Adjustment
June	2010	TO populates the formula with Year 2009 actual data and calculates the 2009 True-Up Adjustment Before Interest
Sept	2010	TO calculates the Interest to include in the 2009 True-Up Adjustment
Sept	2010	TO populates the formula with Year 2011 estimated data and 2009 True-Up Adjustment
June	(Year)	TO populates the formula with (Year -1) actual data and calculates the (Year-1) True-Up Adjustment Before Interest
Sept	(Year)	TO calculates the Interest to include in the (Year-1) True-Up Adjustment
Sept	(Year)	TO populates the formula with (Year +1) estimated data and (Year-1) True-Up Adjustment

[1] No True-Up Adjustment will be included in the annual revenue requirements for 2008 or 2009 since the Formula Rate was not in effect for 2006 or 2007. For all true-up calculations, the ATRR will be adjusted to exclude any true-up adjustment.

[2] To the extent possible, each input to the Formula Rate used to calculate the actual Annual Revenue Requirement included in the True-Up Adjustment either will be taken directly from the FERC Form No. 1 or will be reconcilable to the FERC Form No. 1 by the application of clearly identified and supported information. If the reconciliation is provided through a worksheet included in the filed Formula Rate template, the inputs to the worksheet must meet this transparency standard, and doing so will satisfy this transparency requirement for the amounts that are output from the worksheet and input to the main body of the Formula Rate.

Virginia Electric and Power Company
ATTACHMENT H-16A
Attachment 7 - Transmission Enhancement Annual Revenue Requirement Worksheet
(dollars)

1 New Plant Carrying Charge

2 **Fixed Charge Rate (FCR) if not a CIAC**

		Formula Line		
3	A	154	Net Plant Carrying Charge without Depreciation	16.8957%
4	B	161	Net Plant Carrying Charge per 100 Basis Point increase in ROE without Depreciation	17.6658%
5	C		Line B less Line A	0.7700%

6 **FCR if a CIAC**

7	D	155	Net Plant Carrying Charge without Depreciation, Return, or Income Taxes	5.5951%

8 **The FCR resulting from Formula is for the rate period only.**
9 **Therefore actual revenues collected or the lack of revenues collected in other years are not applicable.**

10	Details		Project A				Project B			
11	Schedule 12	(Yes or No)	Yes	b0217			Yes	b0222		
12	Life		51	Upgrade Mt.Storm - Doubs 500 kV			51	Install 150 MVAR capacitor		
13	FCR W/O incentive	Line 3	16.8957%				16.8957%			
14	Incentive Factor (Basis Points /100)		0				0			
15	FCR W incentive L.13 +(L.14*L.5)		16.8957%				16.8957%			
16	Investment		1,911,000				1,671,324			
17	Annual Depreciation Exp		37,471				32,771			
18	In Service Month (1-12)		6				6			
19		**Invest Yr**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**
20	W / O incentive	2006	1,911,000	20,297	1,890,703		1,671,324	17,751	1,653,573	-
21	W incentive	2006	1,911,000	20,297	1,890,703	-	1,671,324	17,751	1,653,573	-
22	W / O incentive	2007	1,890,703	37,471	1,853,233	-	1,653,573	32,771	1,620,802	-
23	W incentive	2007	1,890,703	37,471	1,853,233	-	1,653,573	32,771	1,620,802	-
24	W / O incentive	2008	1,853,233	37,471	1,815,762	347,423	1,620,802	32,771	1,588,031	303,849
25	W incentive	2008	1,853,233	37,471	1,815,762	347,423	1,620,802	32,771	1,588,031	303,849

Lines continues as new rate years as added.

In the formulas used in the Columns for lines 19+ are as follows:
"In Service Month" is the first month during the first year that the project is placed in service or recovery is request for the project.
"Beginning" is the investment on line 16 for the first year and is the "Ending" for the prior year after the first year.
"Depreciation" is the annual depreciation in line 17 divided by twelve times the difference of 12.5 minus line 18 in the first year and line 17 thereafter.
"Ending" is "Beginning" less "Depreciation"
Revenue Requirement used for crediting is ("Beginning" plus "Ending") divided by two times line 13 times the quotient of 12.5 minus line 18 divided by 12 plus "Depreciation" for the first year and ("Beginning" plus "Ending") divided by two times line 13 plus "Depreciation" thereafter.
Revenue Requirement used for charging is ("Beginning" plus "Ending") divided by two times line 15 times the quotient of 12.5 minus line 18 divided by 12 plus "Depreciation" for the first year and ("Beginning" plus "Ending") divided by two times line 15 plus "Depreciation" thereafter.
Formula Logic to be copied on new lines added each year after line 25. Using 2009 as an example, the logic will be included in lines 26 and 27.
Beginning with the annual revenue requirements determined in 2009 for 2010, the annual revenue requirements based on projected costs will include a True-Up Adjustment for the previous calendar year in accordance with Attachment 6 A and as calculated in Lines A through I below
Projected Revenue Requirements are calculated using the logic described for lines 19 + but with projected data for the indicated year.
Actual Revenue Requirements are calculated using the logic described for lines 19 + but with actual data for the indicated year.

Calendar Year — Do for Each Calendar Year beginning in 2009 for True-Up Adjustments applicable to 2010 annual revenue requirements.

		Project A	Project B
A	Projected Revenue Requirement without Incentive for Previous Calendar Year*		
B	Projected Revenue Requirement with Incentive for Previous Calendar Year*		
C	Actual Revenue Requirement without Incentive for Previous Calendar Year *		
D	Actual Revenue Requirement with Incentive for Previous Calendar Year *		
E	True-Up Adjustment Before Interest without Incentive for Next Calendar Year (C-A)	-	-
F	True-Up Adjustment Before Interest with Incentive for Previous Calendar Year (B-D)	-	-
G	Future Value Factor (1+i)^24 months from Attachment 6	-	-
H	True-Up Adjustment without Incentive (E*G)	-	-
I	True-Up Adjustment with Incentive (F*G)	-	-

* These amounts do not include any True-Up Adjustments.

Additional columns to be inserted after the last project as new projects are added to formula.

Virginia Electric and Power Company
ATTACHMENT H-16A
Attachment 7 - Transmission Enhancement Annual Revenue Requirement Worksheet
(dollars)

Project C				Project D				Project E			
Yes	b0223 and b0224			Yes	B0225			Yes	B0226		
51	Install 150 MVAR capacitors			51	Install 33 MVAR capacitor at			51	Install 500/230 kV transformer at		
16.8957%				16.8957%	Possum Pt. 115 kV			16.8957%	Clifton and Clifton 500 KV 150 MVAR		
0				0				0	capacitor		
16.8957%				16.8957%				16.8957%			
2,138,274				857,172				8,712,162			
41,927				16,807				170,827			
6				6				6			
Beginning	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**
2,138,274	22,710	2,115,564	-	857,172	9,104	848,068	-	8,712,162	92,531	8,619,631	-
2,138,274	22,710	2,115,564	-	857,172	9,104	848,068	-	8,712,162	92,531	8,619,631	-
2,115,564	41,927	2,073,637	-	848,068	16,807	831,261	-	8,619,631	170,827	8,448,804	-
2,115,564	41,927	2,073,637	-	848,068	16,807	831,261	-	8,619,631	170,827	8,448,804	-
2,073,637	41,927	2,031,710	388,741	831,261	16,807	814,453	155,835	8,448,804	170,827	8,277,977	1,583,884
2,073,637	41,927	2,031,710	388,741	831,261	16,807	814,453	155,835	8,448,804	170,827	8,277,977	1,583,884

-	-	-
-	-	-
-	-	-
-	-	-
-	-	-

Virginia Electric and Power Company
ATTACHMENT H-16A
Attachment 7 - Transmission Enhancement Annual Revenue Requirement Worksheet
(dollars)

Project F				Project G				If Yes for Schedule 12 Include in this Total.	If No for Schedule 12 include in this Sum.	
Yes	B0341			Yes	B0403					
51	Install a breaker at Northern Neck 115 kV			51	2nd Dooms 500/230 kV transformer addition					
16.8957%				16.8957%						
0				0						
16.8957%				16.8957%						
2,050,992				8,465,714					Annual Revenue Requirement including Incentive if Applicable	Annual Revenue Requirement excluding Incentive
40,216				165,994						
6				6						
Beginning	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Total**	**Sum**	**Sum**
2,050,992	21,783	2,029,209						$ -		
2,050,992	21,783	2,029,209						$ -		
2,029,209	40,216	1,988,993		8,465,714	89,914	8,375,800		$ -		
2,029,209	40,216	1,988,993		8,465,714	89,914	8,375,800		$ -		
1,988,993	40,216	1,948,778	372,873	8,375,800	165,994	8,209,806	1,567,125	$ 4,719,731		$ -
1,988,993	40,216	1,948,778	372,873	8,375,800	165,994	8,209,806	1,567,125	$ 4,719,731	$ -	

-	-
-	-
-	-
-	-
-	-

Virginia Electric and Power Company
ATTACHMENT H-16A
Attachment 8 - Securitization Workpaper
(000's)

Line #		
	Long Term Interest	
105	**Less LTD Interest on Securitization Bonds**	0
	Capitalization	
115	**Less LTD on Securitization Bonds**	0

Virginia Electric and Power Company
ATTACHMENT H-16A
Attachment 9 - Depreciation Rates[1]

Plant Type	Applied Depreciation Rate
Transmission	1.97%
General	
Structures and Improvements	1.86%
Communication Equipment	3.67%
Computer Equipment	16.51%
Furniture, Equipment and Office Machines	1.64%
Laboratory and Miscellaneous Equipment	4.10%
Stores and Power Operated Equipment	6.31%
Tools, Shop, Garage, and Other Tangible Equipment	4.93%

[1]Depreciation rates may be changed only pursuant to a Section 205 or Section 206 proceeding.

Attachment 7b
TrailCo Formula Rate Update Compliance Filing

(15) Monongahela Power Company, The Potomac Edison Company, and West Penn Power Company, all doing business as Allegheny Power

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0216	Install -100/+525 MVAR dynamic reactive device at Black Oak	As specified under the procedures detailed in Attachment H-18B, Section 1.b	AEC (2.05%) / AEP (16.79%) / APS (5.96%) / BGE (4.91%) / ComEd (16.11%) / Dayton (2.53%) / DL (2.08%) / DPL (2.93%) / Dominion (13.22%) / JCPL (4.57%) / ME (2.04%) / NEPTUNE* (0.47%) / PECO (6.10%) / PENELEC (2.09%) / PEPCO (4.74%) / PPL (5.16%) / PSEG (7.58%) / RE (0.30%) / UGI (0.14%) / ECP** (0.23%)
b0218	Install third Wylie Ridge 500/345kV transformer	As specified under the procedures detailed in Attachment H-18B, Section 1.b	AEC (4%) / APS (3%) / BGE (9%) / DPL (7%) / Dominion (12%) / JCPL (10%) / ME (5%) / PECO (13%) / PENELEC (2%) / PEPCO (8%) / PPL (11%) / PSEG (15%) / RE (1%)
b0220	Upgrade coolers on Wylie Ridge 500/345 kV #7		Dominion (18%) / JCP&L (14%) / PECO (19%) / PEPCO (11%) / PP&L (16%) / PSE&G (22%)
b0229	Install fourth Bedington 500/138 kV		AE (2%) / APS (13%) / BG&E (13%) / DP&L (3%) / Dominion (33%) / JCP&L (3%) / Met-Ed (2%) / PECO (6%) / PEPCO (16%) / PP&L (4%) / PSE&G (5%)
b0230	Install fourth Meadowbrook 500/138 kV	As specified under the procedures detailed in Attachment H-18B, Section 1.b	AE (2%) / APS (60%) / BG&E (6%) / DP&L (3%) / JCP&L (4%) / Met-Ed (2%) / PECO (6%) / PENELEC (1%) / PEPCO (6%) / PP&L (4%) / PSE&G (6%)

* Neptune Regional Transmission System, LLC
** East Coast Power, L.L.C.

Monongahela Power Company, The Potomac Edison Company, and West Penn Power Company, all doing business as Allegheny Power (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0238	Reconductor Doubs – Dickerson and Doubs – Aqueduct 1200 MVA	As specified under the procedures detailed in Attachment H-18B, Section 1.b	AEC (2%) / BGE (19%) / DPL (4%) / Dominion (19%) / JCPL (4%) / METED (2%) / PECO (7%) / PEPCO (31%) / PPL (5%) / PSEG (7%)
b0240	Open the Black Oak #3 500/138 kV transformer for the loss of Hatfield – Back Oak 500 kV line		APS (100%)
b0245	Replacement of the existing 954 ACSR conductor on the Bedington – Nipetown 138 kV line with high temperature/low sag conductor		APS (24%) / BGE (20%) / Dominion (32%) / PEPCO (24%)
b0246	Rebuild of the Double Tollgate – Old Chapel 138 kV line with 954 ACSR conductor	As specified under the procedures detailed in Attachment H-18B, Section 1.b	AEC (3%) / APS (9%) / BGE (15%) / DPL (6%) / Dominion (9%) / JCPL (7%) / METED (4%) / PECO (11%) / PEPCO (17%) / PPL (8%) / PSEG (11%)
b0273	Open both North Shenandoah #3 transformer and Strasburg – Edinburgh 138 kV line for the loss of Mount Storm – Meadowbrook 572 500 kV		APS (100%)
b0321	Install a new Prexy 500 kV substation and Prexy to 502 Junction 500 kV circuit	As specified under the procedures detailed in Attachment H-18B, Section 1.b	AEC (2.05%) / AEP (16.79%) / APS (5.96%) / BGE (4.91%) / ComEd (16.11%) / Dayton (2.53%) / DL (2.08%) / DPL (2.93%) / Dominion (13.22%) / JCPL (4.57%) / ME (2.04%) / NEPTUNE* (0.47%) / PECO (6.10%) / PENELEC (2.09%) / PEPCO (4.74%) / PPL (5.16%) / PSEG (7.58%) / RE (0.30%) / UGI (0.14%) / ECP** (0.23%)†
b0321	Install a new Prexy 500 kV substation and Prexy to 502 Junction 500 kV circuit	As specified under the procedures detailed in Attachment H-18B, Section 1.b	APS (100%)††

* Neptune Regional Transmission System, LLC
** East Coast Power, L.L.C.
†Cost allocations associated with Regional Facilities and Necessary Lower Voltage Facilities associated with the project
††Cost allocations associated with below 500 kV elements of the project

Monongahela Power Company, The Potomac Edison Company, and West Penn Power Company, all doing business as Allegheny Power (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0322	Convert Lime Kiln substation to 230 kV operation		APS (100%)
b0323	Replace the North Shenandoah 138/115 kV transformer	As specified under the procedures detailed in Attachment H-18B, Section 1.b	AEC (3%) / APS (29%) / BGE (13%) / DPL (5%) / JCPL (6%) / ME (3%) / PECO (9%) / PEPCO (14%) / PPL (7%) / PSEG (11%)
b0328.2	Build new Meadow Brook – Loudoun 500 kV circuit (20 of 50 miles)	As specified under the procedures detailed in Attachment H-18B, Section 1.b	AEC (2.05%) / AEP (16.79%) / APS (5.96%) / BGE (4.91%) / ComEd (16.11%) / Dayton (2.53%) / DL (2.08%) / DPL (2.93%) / Dominion (13.22%) / JCPL (4.57%) / ME (2.04%) / NEPTUNE* (0.47%) / PECO (6.10%) / PENELEC (2.09%) / PEPCO (4.74%) / PPL (5.16%) / PSEG (7.58%) / RE (0.30%) / UGI (0.14%) / ECP** (0.23%)
b0343	Replace Doubs 500/230 kV transformer #2	As specified under the procedures detailed in Attachment H-18B, Section 1.b	AEC (4%) / BGE (19%) / DPL (6%) / JCPL (8%) / ME (4%) / NEPTUNE* (1%) / PECO (12%) / PEPCO (23%) / PENELEC (1%) / PPL (9%) / PSEG (13%)
b0344	Replace Doubs 500/230 kV transformer #3	As specified under the procedures detailed in Attachment H-18B, Section 1.b	AEC (4%) / BGE (19%) / DPL (6%) / JCPL (8%) / ME (4%) / NEPTUNE* (1%) / PECO (12%) / PEPCO (23%) / PENELEC (1%) / PPL (9%) / PSEG (13%)
b0345	Replace Doubs 500/230 kV transformer #4	As specified under the procedures detailed in Attachment H-18B, Section 1.b	AEC (4%) / BGE (19%) / DPL (6%) / JCPL (8%) / ME (4%) / NEPTUNE* (1%) / PECO (12%) / PEPCO (23%) / PENELEC (1%) / PPL (9%) / PSEG (13%)

* Neptune Regional Transmission System, LLC
** East Coast Power, L.L.C.

Monongahela Power Company, The Potomac Edison Company, and West Penn Power Company, all doing business as Allegheny Power (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0347.1	Build new Mt. Storm – 502 Junction 500 kV circuit	As specified under the procedures detailed in Attachment H-18B, Section 1.b	AEC (2.05%) / AEP (16.79%) / APS (5.96%) / BGE (4.91%) / ComEd (16.11%) / Dayton (2.53%) / DL (2.08%) / DPL (2.93%) / Dominion (13.22%) / JCPL (4.57%) / ME (2.04%) / NEPTUNE* (0.47%) / PECO (6.10%) / PENELEC (2.09%) / PEPCO (4.74%) / PPL (5.16%) / PSEG (7.58%) / RE (0.30%) / UGI (0.14%) / ECP** (0.23%)
b0347.2	Build new Mt. Storm – Meadow Brook 500 kV circuit	As specified under the procedures detailed in Attachment H-18B, Section 1.b	AEC (2.05%) / AEP (16.79%) / APS (5.96%) / BGE (4.91%) / ComEd (16.11%) / Dayton (2.53%) / DL (2.08%) / DPL (2.93%) / Dominion (13.22%) / JCPL (4.57%) / ME (2.04%) / NEPTUNE* (0.47%) / PECO (6.10%) / PENELEC (2.09%) / PEPCO (4.74%) / PPL (5.16%) / PSEG (7.58%) / RE (0.30%) / UGI (0.14%) / ECP** (0.23%)

* Neptune Regional Transmission System, LLC
** East Coast Power, L.L.C.

Monongahela Power Company, The Potomac Edison Company, and West Penn Power Company, all doing business as Allegheny Power (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0347.3	Build new 502 Junction 500 kV substation	As specified under the procedures detailed in Attachment H-18B, Section 1.b	AEC (2.05%) / AEP (16.79%) / APS (5.96%) / BGE (4.91%) / ComEd (16.11%) / Dayton (2.53%) / DL (2.08%) / DPL (2.93%) / Dominion (13.22%) / JCPL (4.57%) / ME (2.04%) / NEPTUNE* (0.47%) / PECO (6.10%) / PENELEC (2.09%) / PEPCO (4.74%) / PPL (5.16%) / PSEG (7.58%) / RE (0.30%) / UGI (0.14%) / ECP** (0.23%)
b0347.4	Upgrade Meadow Brook 500 kV substation	As specified under the procedures detailed in Attachment H-18B, Section 1.b	AEC (2.05%) / AEP (16.79%) / APS (5.96%) / BGE (4.91%) / ComEd (16.11%) / Dayton (2.53%) / DL (2.08%) / DPL (2.93%) / Dominion (13.22%) / JCPL (4.57%) / ME (2.04%) / NEPTUNE* (0.47%) / PECO (6.10%) / PENELEC (2.09%) / PEPCO (4.74%) / PPL (5.16%) / PSEG (7.58%) / RE (0.30%) / UGI (0.14%) / ECP** (0.23%)

* Neptune Regional Transmission System, LLC
** East Coast Power, L.L.C.

Monongahela Power Company, The Potomac Edison Company, and West Penn Power Company, all doing business as Allegheny Power (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0348	Upgrade Stonewall – Inwood 138 kV with 954 ACSR conductor		APS (16%) / BGE (16%) / DPL (6%) / JCPL (8%) / ME (4%) / PECO (11%) / PEPCO (17%) / PPL (9%) / PSEG (13%)
b0373	Convert Doubs – Monocacy 138 kV facilities to 230 kV operation		APS (88%) / ME (12%)
b0393	Replace terminal equipment at Harrison 500 kV and Belmont 500 kV		AEC (2.05%) / AEP (16.79%) / APS (5.96%) / BGE (4.91%) / ComEd (16.11%) / Dayton (2.53%) / DL (2.08%) / DPL (2.93%) / Dominion (13.22%) / JCPL (4.57%) / ME (2.04%) / NEPTUNE* (0.47%) / PECO (6.10%) / PENELEC (2.09%) / PEPCO (4.74%) / PPL (5.16%) / PSEG (7.58%) / RE (0.30%) / UGI (0.14%) / ECP** (0.23%)
b0406.1	Replace Mitchell 138 kV breaker "#4 bank"		APS (100%)
b0406.2	Replace Mitchell 138 kV breaker "#5 bank"		APS (100%)
b0406.3	Replace Mitchell 138 kV breaker "#2 transf"		APS (100%)
b0406.4	Replace Mitchell 138 kV breaker "#3 bank"		APS (100%)
b0406.5	Replace Mitchell 138 kV breaker "Charlerio #2"		APS (100%)

* Neptune Regional Transmission System, LLC
** East Coast Power, L.L.C.

Monongahela Power Company, The Potomac Edison Company, and West Penn Power Company, all doing business as Allegheny Power (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0406.6	Replace Mitchell 138 kV breaker “Charlerio #1”		APS (100%)
b0406.7	Replace Mitchell 138 kV breaker “Shepler Hill Jct”		APS (100%)
b0406.8	Replace Mitchell 138 kV breaker “Union Jct”		APS (100%)
b0406.9	Replace Mitchell 138 kV breaker “#1-2 138 kV bus tie”		APS (100%)
b0407.1	Replace Marlowe 138 kV breaker “#1 transf”		APS (100%)

Monongahela Power Company, The Potomac Edison Company, and West Penn Power Company, all doing business as Allegheny Power (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0407.2	Replace Marlowe 138 kV breaker “MBO”		APS (100%)
b0407.3	Replace Marlowe 138 kV breaker “BMA”		APS (100%)
b0407.4	Replace Marlowe 138 kV breaker “BMR”		APS (100%)
b0407.5	Replace Marlowe 138 kV breaker “WC-1”		APS (100%)
b0407.6	Replace Marlowe 138 kV breaker “R11”		APS (100%)
b0407.7	Replace Marlowe 138 kV breaker “W”		APS (100%)
b0407.8	Replace Marlowe 138 kV breaker “138 kV bus tie”		APS (100%)
b0408.1	Replace Trissler 138 kV breaker “Belmont 604”		APS (100%)
b0408.2	Replace Trissler 138 kV breaker “Edgelawn 90”		APS (100%)
b0409.1	Replace Weirton 138 kV breaker “Wylie Ridge 210”		APS (100%)
b0409.2	Replace Weirton 138 kV breaker “Wylie Ridge 216”		APS (100%)
b0410	Replace Glen Falls 138 kV breaker “McAlpin 30”		APS (100%)
b0417	Reconductor Mitchell – Shepler Hill Junction 138kV with 954 ACSR		

Monongahela Power Company, The Potomac Edison Company, and West Penn Power Company, all doing business as Allegheny Power (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0418	Install a breaker failure auto-restoration scheme at Cabot 500 kV for the failure of the #6 breaker		AEC (2.05%) / AEP (16.79%) / APS (5.96%) / BGE (4.91%) / ComEd (16.11%) / Dayton (2.53%) / DL (2.08%) / DPL (2.93%) / Dominion (13.22%) / JCPL (4.57%) / ME (2.04%) / NEPTUNE* (0.47%) / PECO (6.10%) / PENELEC (2.09%) / PEPCO (4.74%) / PPL (5.16%) / PSEG (7.58%) / RE (0.30%) / UGI (0.14%) / ECP** (0.23%)
b0419	Install a breaker failure auto-restoration scheme at Bedington 500 kV for the failure of the #1 and #2 breakers		AEC (2.05%) / AEP (16.79%) / APS (5.96%) / BGE (4.91%) / ComEd (16.11%) / Dayton (2.53%) / DL (2.08%) / DPL (2.93%) / Dominion (13.22%) / JCPL (4.57%) / ME (2.04%) / NEPTUNE* (0.47%) / PECO (6.10%) / PENELEC (2.09%) / PEPCO (4.74%) / PPL (5.16%) / PSEG (7.58%) / RE (0.30%) / UGI (0.14%) / ECP** (0.23%)
b0420	Operating Procedure to open the Black Oak 500/138 kV transformer #3 for the loss of Hatfield – Ronco 500 kV and the Hatfield #3 Generation		APS (100%)
b0445	Upgrade substation equipment and reconductor the Tidd – Mahans Lane – Weirton 138kV circuit with 954 ACSR		

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** East Coast Power, L.L.C.

Monongahela Power Company, The Potomac Edison Company, and West Penn Power Company, all doing business as Allegheny Power (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0460	Raise limiting structures on Albright – Bethelboro 138 kV to raise the rating to 175 MVA normal 214 MVA emergency		
b0491	Construct an Amos – Bedington 765 kV circuit (APS equipment)	As specified under the procedures detailed in Attachment H-19B	AEC (2.05%) / AEP (16.79%) / APS (5.96%) / BGE (4.91%) / ComEd (16.11%) / Dayton (2.53%) / DL (2.08%) / DPL (2.93%) / Dominion (13.22%) / JCPL (4.57%) / ME (2.04%) / Neptune* (0.47%) / PECO (6.10%) / PENELEC (2.09%) / PEPCO (4.74%) / PPL (5.16%) / PSEG (7.58%) / RE (0.30%) / UGI (0.14%) / ECP** (0.23%)
b0492	Construct a Bedington – Kemptown 500 kV circuit	As specified under the procedures detailed in Attachment H-19B	AEC (2.05%) / AEP (16.79%) / APS (5.96%) / BGE (4.91%) / ComEd (16.11%) / Dayton (2.53%) / DL (2.08%) / DPL (2.93%) / Dominion (13.22%) / JCPL (4.57%) / ME (2.04%) / Neptune* (0.47%) / PECO (6.10%) / PENELEC (2.09%) / PEPCO (4.74%) / PPL (5.16%) / PSEG (7.58%) / RE (0.30%) / UGI (0.14%) / ECP** (0.23%)

*Neptune Regional Transmission System, LLC
**East Coast Power, L.L.C.

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May 15, 2008

Ms. Kimberly D. Bose, Secretary
Federal Energy Regulatory Commission
888 First Street, NE
Washington, DC 20426

Re: Trans-Allegheny Interstate Line Company
Electronic Informational Filing of 2008 Formula Rate Annual Update
Docket No. ER07-562-000, *et al.*

Dear Secretary Bose:

Pursuant to the Commission's order dated May 31, 2007 in Docket No. ER07-562-000,[1] Trans-Allegheny Interstate Line Company ("TrAILCo") hereby submits for informational purposes its 2008 Annual Update to recalculate its annual transmission revenue requirements ("Annual Update"). The Annual Update includes (i) a reconciliation of the annual transmission revenue requirements for the 2007 Rate Year[2] (Attachment 1), (ii) the annual transmission revenue requirements for the 2008 Rate Year to become effective on June 1, 2008 (Attachment 2) and (iii) a detailed accounting of transfers between construction work in progress ("CWIP") and Plant in Service as required by the May 31 Order (Attachment 3).

TrAILCo's tariff on file with the Commission specifies that:

> [o]n or before May 15 of each year, TrAILCo shall recalculate its Annual Transmission Revenue Requirements, producing the "Annual Update" for the upcoming Rate Year, and post such Annual Update on PJM's Internet website via link to the Transmission Services page or a similar successor page.[3]

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1 *Trans-Allegheny Interstate Line Company*, 119 FERC ¶ 61,219, P 59 (2007) (May 31 Order").

2 The "Rate Year" begins on June 1 of a given calendar year and continues through May 31 of the subsequent calendar year.

3 PJM Interconnection, L.L.C., FERC Electric Tariff, Sixth Revised Volume No. 1, Substitute Original Sheet No. 314I.25, Attachment H-18B, Section 1(b) (effective June 1, 2007).

The Annual Update attached hereto and submitted to PJM Interconnection, L.L.C. for posting on its Internet website via link to the Transmission Services page includes a recalculation of TrAILCo's annual transmission revenue requirements. This filing incorporates additional detail to support the submittal, in conformance with a settlement in Docket No. ER07-562-004, which was certified to the Commission on April 25, 2008.[4] This additional detail adds to, but does not conflict with, the currently effective tariff on file with the Commission. The Annual Update contains no expenses or costs that have been alleged or judged in any administrative or judicial proceeding to be illegal, duplicative, or unnecessary costs that are demonstrably the produce to discriminatory employment practices, as defined in 18 C.F.R. § 35.13(b)(7). In addition, please note that TrAILCo has made no material changes in its accounting policies and practices from those in effect during the previous Rate Year and upon which the current rate is based.

Thank you for your attention to this informational filing. Please direct any questions to the undersigned.

Respectfully submitted,

/s/ Stephen Angle
Stephen Angle

Attorney for Trans-Allegheny Interstate Line Company

Enclosures

[4] *Trans-Allegheny Interstate Line Company*, 123 FERC ¶ 63,009 (2008).

ATTACHMENT 1

Reconciliation of

Annual Transmission Revenue Requirements

ATTACHMENT H-18A

Trans-Allegheny Interstate Line Company

Formula Rate -- Appendix A

Shaded cells are input cells

Line	Description	Notes	FERC Form 1 Page # or Instruction	TrAILCo
				2007 Reconciliation
	Allocators			
	Wages & Salary Allocation Factor			
1	Transmission Wages Expense		p354.21.b	521,110
2	Total Wages Expense		p354.28.b	1,298,871
3	Less A&G Wages Expense		p354.27.b	777,761
4	Total Wages Less A&G Wages Expense		(Line 2 - Line 3)	521,110
5	**Wages & Salary Allocator**		(Line 1 / Line 4), if line 2 = 0, then 100%	**100.0000%**
	Plant Allocation Factors			
6	Electric Plant in Service	(Note B)	Attachment 5	4,668,030
7	Total Plant In Service		(Line 6)	4,668,030
8	Accumulated Depreciation (Total Electric Plant)		Attachment 5	12
9	Total Accumulated Depreciation		(Line 8)	12
10	Net Plant		(Line 7 - Line 9)	4,668,018
11	Transmission Gross Plant		(Line 15 + Line 21)	4,668,030
12	**Gross Plant Allocator**		(Line 11 / Line 7, if Line 7=0, enter 100%)	**100.0000%**
13	Transmission Net Plant		(Line 11 - Line 29)	4,668,018
14	**Net Plant Allocator**		(Line 13 / Line 10, if line 10=0, enter 100%)	**100.0000%**
	Plant Calculations			
	Transmission Plant			
15	Transmission Plant In Service	(Note B)	Attachment 5	4,668,030
16	New Trans. Plant Adds. for Current Calendar Year (13 average balance)	(Note B)	Attachment 6	0
17	**Total Transmission Plant**		(Line 15 + Line 16)	**4,668,030**
18	General & Intangible		Attachment 5	0
19	Total General & Intangible		(Line 18)	0
20	Wage & Salary Allocator		(Line 5)	100.0000%
21	**Transmission Related General and Intangible Plant**		(Line 19 * Line 20)	**0**
22	**Transmission Related Plant**		**(Line 17 + Line 21)**	**4,668,030**
	Accumulated Depreciation			
23	Transmission Accumulated Depreciation	(Note B)	Attachment 5	12
24	Accumulated General Depreciation		Attachment 5	0
25	Accumulated Intangible Amortization		Attachment 5	0
26	Total Accumulated General and Intangible Depreciation		(Sum Lines 24 to 25)	0
27	Wage & Salary Allocator		(Line 5)	100.0000%
28	**Transmission Related General & Intangible Accumulated Depreciation**		(Line 26 * Line 27)	**0**
29	**Total Transmission Related Accumulated Depreciation**		**(Line 23 + Line 28)**	**12**
30	**Total Transmission Related Net Property, Plant & Equipment**		**(Line 22 - Line 29)**	**4,668,018**

Adjustment To Rate Base

Line	Description	Note	Source	Amount
	Accumulated Deferred Income Taxes			
31	ADIT net of FASB 106 and 109 — Enter Negative		Attachment 1	403,291
32	**Transmission Related Accumulated Deferred Income Taxes**		(Line 31)	**403,291**
33	**Transmission Related CWIP (Current Year 13 Month weighted average balances)**	(Note B)	p216.b.43 as shown on Attachment 6	**10,654,723**
34	**Transmission Related Land Held for Future Use**	(Note C)	Attachment 5	**0**
	Transmission Related Pre-Commercial Costs Capitalized			
35	Unamortized Capitalized Pre-Commercial Costs		Attachment 5	**1,986,901**
	Prepayments			
36	**Transmission Related Prepayments**	(Note A)	Attachment 5	**17,682**
	Materials and Supplies			
37	Undistributed Stores Expense	(Note A)	Attachment 5	0
38	Wage & Salary Allocator		(Line 5)	100.0000%
39	Total Undistributed Stores Expense Allocated to Transmission		(Line 37 * Line 38)	0
40	Transmission Materials & Supplies		Attachment 5	0
41	**Transmission Related Materials & Supplies**		(Line 39 + Line 40)	**0**
	Cash Working Capital			
42	Operation & Maintenance Expense		(Line 74)	5,537,387
43	1/8th Rule		1/8	12.5%
44	**Transmission Related Cash Working Capital**		(Line 42 * Line 43)	**692,173**
45	**Total Adjustment to Rate Base**		(Lines 32 + 33 + 34 + 35+ 36 + 41 + 44)	**13,754,770**
46	**Rate Base**		(Line 30 + Line 45)	**18,422,788**

O&M

Line	Description	Note	Source	Amount
	Transmission O&M			
47	Transmission O&M		p321.112.b	3,502,178
48	Less Account 566 Misc Trans Exp listed on line 73 below.)		(line 73)	1,301,854
49	Less Account 565		p321.96.b	0
50	Plus Schedule 12 Charges billed to Transmission Owner and booked to Account 565	(Note M)	PJM Data	0
51	Plus Property Under Capital Leases		p200.4.c	0
52	**Transmission O&M**		(Lines 47 - 48 - 49 + 50 + 51)	**2,200,324**
	A&G Expenses			
53	Total A&G		p323.197.b	2,061,274
54	Less Property Insurance Account 924		p323.185.b	0
55	Less Regulatory Commission Exp Account 928	(Note E)	p323.189.b	0
56	Less General Advertising Exp Account 930.1		p323.191.b	0
57	Less PBOP Adjustment		Attachment 5	26,065
58	Less EPRI Dues	(Note D)	p352 & 353	0
59	**A&G Expenses**		(Line 53) - Sum (Lines 54 to 58)	2,035,209
60	Wage & Salary Allocator		(Line 5)	100.0000%
61	**Transmission Related A&G Expenses**		(Line 59 * Line 60)	**2,035,209**
	Directly Assigned A&G			
62	Regulatory Commission Exp Account 928	(Note G)	Attachment 5	0
63	General Advertising Exp Account 930.1	(Note J)	Attachment 5	0
64	Subtotal - Accounts 928 and 930.1 - Transmission Related		(Line 62 + Line 63)	**0**
65	Property Insurance Account 924		p323.185.b	0
66	General Advertising Exp Account 930.1	(Note F)	Attachment 5	0
67	Total Accounts 928 and 930.1 - General		(Line 65 + Line 66)	0
68	Net Plant Allocator		(Line 14)	100.0000%
69	**A&G Directly Assigned to Transmission**		(Line 67 * Line 68)	**0**
	Account 566 Miscellaneous Transmission Expense			
70	Amortization Expense on Pre-Commercial Cost	Account 566	Attachment 5	567,686
71	Pre-Commercial Expense	Account 566	Attachment 5	734,168
72	Miscellaneous Transmission Expense	Account 566	Attachment 5	0
73	Total Account 566		Sum (Lines 70 to 72)	**1,301,854**
74	**Total Transmission O&M**		**(Lines 52 + 61 + 64 + 69 + 73)**	**5,537,387**

Depreciation & Amortization Expense

	Depreciation Expense				
75	Transmission Depreciation Expense			Attachment 5	102
76	General Depreciation			p336.10.b&c	0
77	Intangible Amortization		(Note A)	p336.1.d&e	0
78	Total			(Line 76 + Line 77)	0
79	Wage & Salary Allocator			(Line 5)	100.0000%
80	**Transmission Related General Depreciation and Intangible Amortization**			(Line 78 * Line 79)	**0**
81	**Total Transmission Depreciation & Amortization**			**(Lines 75 + 80)**	**102**

Taxes Other than Income

82	**Transmission Related Taxes Other than Income**			Attachment 2	**171,335**
83	**Total Taxes Other than Income**			**(Line 82)**	**171,335**

Return / Capitalization Calculations

84	**Preferred Dividends**		enter positive	p118.29.c	0
	Common Stock				
85	Proprietary Capital			p112.16.c	78,829,523
86	Less Accumulated Other Comprehensive Income Account 219			p112.15.c	0
87	Less Preferred Stock			(Line 95)	0
88	Less Account 216.1			p112.12.c	0
89	**Common Stock**			(Line 85 - 86 - 87 - 88)	78,829,523
	Capitalization				
90	Long Term Debt		(Note N)		0
91	Less Unamortized Loss on Reacquired Debt			p111.81.c	0
92	Plus Unamortized Gain on Reacquired Debt			p113.61.c	0
93	Less ADIT associated with Gain or Loss			Attachment 1	0
94	Total Long Term Debt			(Line 90 - 91 + 92 - 93)	0
95	Preferred Stock			p112.3.c	0
96	Common Stock			(Line 89)	78,829,523
97	**Total Capitalization**			(Sum Lines 94 to 96)	78,829,523
98	Debt %	Total Long Term Debt	(Note N)	(Line 94 /Line 97)	50.0%
99	Preferred %	Preferred Stock	(Note N)	(Line 95 /Line 97)	0.0%
100	Common %	Common Stock	(Note N)	(Line 96 /Line 97)	50.0%
101	Debt Cost	Total Long Term Debt			0.079
102	Preferred Cost	Preferred Stock		(Line 84 / Line 95)	0.0000
103	Common Cost	Common Stock	(Note I)	The most recent FERC approved ROE	0.1170
104	Weighted Cost of Debt	Total Long Term Debt (WCLTD)		(Line 98 * Line 101)	0.03950
105	Weighted Cost of Preferred	Preferred Stock		(Line 99 * Line 102)	0.0000
106	Weighted Cost of Common	Common Stock		(Line 100 * Line 103)	0.0585
107	**Rate of Return on Rate Base (ROR)**			(Sum Lines 104 to 106)	**0.09800**
108	**Investment Return = Rate Base * Rate of Return**			**(Line 46 * Line 107)**	**1,805,433**

Composite Income Taxes

	Income Tax Rates			
109	FIT=Federal Income Tax Rate	(Note H)		35.00%
110	SIT=State Income Tax Rate or Composite			9.30%
111	p	(percent of federal income tax deductible for state purpo	Per State Tax Code	0.00%
112	T	T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =		41.05%
113	T/ (1-T)			69.62%
114	**Income Tax Component =**	CIT=(T/1-T) * Investment Return * (1-(WCLTD/R)) =	[Line 113 * Line 108 * (1- (Line 104 / Line 107))]	**750,327**
115	**Total Income Taxes**		**(Line 114)**	**750,327**

REVENUE REQUIREMENT

	Summary			
116	Net Property, Plant & Equipment		(Line 30)	4,668,018
117	Total Adjustment to Rate Base		(Line 45)	13,754,770
118	**Rate Base**		(Line 46)	**18,422,788**
119	Total Transmission O&M		(Line 74)	5,537,387
120	Total Transmission Depreciation & Amortization		(Line 81)	102
121	Taxes Other than Income		(Line 83)	171335
122	Investment Return		(Line 108)	1,805,433
123	Income Taxes		(Line 115)	750,327
124	**Gross Revenue Requirement**		**(Sum Lines 119 to 123)**	**8,264,584**
	Adjustment to Remove Revenue Requirements Associated with Excluded Transmission Facilities			
125	Transmission Plant In Service		(Line 22)	4,668,030
126	Excluded Transmission Facilities	(Note L)	Attachment 5	0
127	Included Transmission Facilities		(Line 125 - Line 126)	4,668,030
128	Inclusion Ratio		(Line 127 / Line 125)	100.00%
129	Gross Revenue Requirement		(Line 124)	8,264,584
130	**Adjusted Gross Revenue Requirement**		(Line 128 * Line 129)	**8,264,584**
	Revenue Credits			
131	**Revenue Credits**		Attachment 3	0
132	**Net Revenue Requirement**		**(Line 130 - Line 131)**	**8,264,584**
	Net Plant Carrying Charge			
133	Gross Revenue Requirement		(Line 129)	**8,264,584**
134	Net Transmission Plant + CWIP		(Line 17 - Line 23 + Line 33)	**15,322,741**
135	FCR		(Line 133 / Line 134)	**53.9367%**
136	FCR without Depreciation		(Line 133 - Line 75) / Line 134	**53.9361%**
137	FCR without Depreciation and Pre-Commercial Costs		(Line 133 - Line 70 - Line 71 - Line 75) / Line 134	**45.4398%**
138	FCR without Depreciation, Return, nor Income Taxes		(Line 133 - Line 75 - Line 108 - Line 115) / Line 134	**37.2565%**
	Net Plant Carrying Charge Calculation with Incentive ROE			
139	Gross Revenue Requirement Less Return and Taxes		(Line 129 - Line 122 - Line 123)	**5,708,824**
140	Increased Return and Taxes		Attachment 4	**2,712,005**
141	Net Revenue Requirement with Incentive ROE		(Line 139 + Line 140)	**8,420,829**
142	Net Transmission Plant + CWIP		(Line 17 - Line 23+Line 33)	**15,322,741**
143	FCR with Incentive ROE		(Line 141 / Line 142)	**54.9564%**
144	FCR with Incentive ROE without Depreciation		(Line 141 - Line 75) / Line 142	**54.9557%**
145	FCR with Incentive ROE without Depreciation and Pre-Commercial		(Line 141 - Line 70 - Line 71 - Line 75) / Line 142	**46.4595%**
146	**Net Revenue Requirement**		(Line 132)	**8,264,584**
147	Reconciliation amount		Attachment 6	0
148	Plus any increased ROE calculated on Attach 7 other than PJM Sch. 12 projects not paid by other PJM trans zones		Attachment 7	**146,078**
149	Facility Credits under Section 30.9 of the PJM OATT		Attachment 5	**0**
150	**Net Zonal Revenue Requirement**		(Line 146 + 147 + 148 + 149)	**8,410,662**
	Network Zonal Service Rate			
151	1 CP Peak	(Note K)	PJM Data	**N/A**
152	Rate ($/MW-Year)		(Line 150 / 151)	**N/A**
153	**Network Service Rate ($/MW/Year)**		**(Line 152)**	**N/A**

Notes

A Electric portion only

B For both the estimate and the reconciliation, Construction Work In Progress ("CWIP") and leases that are expensed as O&M (rather than amortized) are excluded.

For the Estimate Process:

Transmission plant in service will show the end of year balance and is linked to Attachment 5 which shows detail support by project.
The transmission plant will agree to or be reconciled to the FERC Form 1 balance for the transmission plant.
New Transmission Plant expected to be placed in service in the current calendar year will be based on the average of 13 monthly investment costs and shown separately detailed by project on Attachment 6.
Accumulated depreciation will show the end of year balance and is linked to Attachment 5 which shows detail support by project.
CWIP will be linked to Attachment 6 which shows detail support by project (incentive and non-incentive).

For the Reconciliation Process:

Transmission plant in service will be calculated using a 13 month average balance and will be detailed on Attachment 5. This includes new transmission plant added to plant-in-service
Accumulated depreciation will be calculated using a 13 month average balance and will be detailed on Attachment 5. This includes accumulated depreciation associated with current year transmission plant.
CWIP will be linked to Attachment 6 which shows detail support by project (incentive and non-incentive).

C Includes Transmission portion only and (i) only land that has an estimated in-service date within 10 years may be included and (ii) a plan for the land's use is required to be included in the filing whenever the cost of the land is proposed to be included in rates.

D Excludes all EPRI Annual Membership Dues

E Excludes all Regulatory Commission Expenses

F Includes Safety related advertising included in Account 930.1

G Includes Regulatory Commission Expenses directly related to transmission service, RTO filings, or transmission siting itemized in Form 1 at 351.h.

H 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 includes taxes in more than one state, it must explain in Attachment 5 the name of each state and how the blended or composite SIT was developed.

I ROE will be established in the Commission order accepting the settlement in Docket No. ER07-562 and no change in ROE will be made absent a Section 205 or Section 206 filing at FERC.

J Education and outreach expenses relating to transmission, for example siting or billing

K As provided for in Section 34.1 of the PJM OATT; the PJM established billing determinants will not be revised or updated in the annual rate reconciliations.

L Amount of transmission plant excluded from rates per Attachment 5.

M Payments made under Schedule 12 of the PJM OATT that are not directly assessed to load in the Zone under Schedule 12 are included in Transmission O&M on Line 47. If they are booked to Acct 565, they are included on Line 50. Copies of PJM invoices will be provided upon request.

N The capital structure will remain 50% equity and 50% debt until construction of all of the segments of the TrAIL Project is completed and the entire TrAIL Project is placed in service. The first year that these projects are in service the formula will be run based on the 50/50 capital structure and on the actual year end capital structure. The two results will be weighted based on: the number of days the last project was in service and 365 day minus the numbers of days the last project was in service divided by 365 days.
This can be illustrated using the following example:

Example:

Assume Last Project goes into service on day 260.
Hypothetical Capital Structure until the last project goes into service is 50/50.
Assume Year End actual capital structure is 60% equity and 40% debt.

Therefore: Weighted Equity = [50%*260+60%*(365-260)]/365

Trans-Allegheny Interstate Line Company

Attachment 1 - Accumulated Deferred Income Taxes (ADIT) Worksheet

	B1	B2	B3	C	D	E	F	G	
					Trans-Allegheny Interstate Company				
	Beg of Year Total	***End of Year Total***	**End of Year for Est. Average for Final** ***Total***	**Retail Related**	**Only Transmission Related**	**Plant Related**	**Labor Related**	**Total ADIT**	
ADIT- 282 From Account Total Below	13,935	366,313	190,124	[redacted]	190,124	-	-	190,124	
ADIT-283 From Account Total Below	-	778,287	389,144	[redacted]	389,144	-	-	389,144	
ADIT-190 From Account Total Below	-	(1,965,117)	(982,559)	[redacted]	(982,559)	-	-	(982,559)	Enter Negative
Subtotal					(403,291)	-	-	(403,291)	
Wages & Salary Allocator							100.0000%		
Gross Plant Allocator						100.0000%			
ADIT					(403,291)	-	-	**(403,291)**	

Note: ADIT associated with Gain or Loss on Reacquired Debt is included in Column A here and included in Cost of Debt on Appendix A, Line 93.

Amount 0 < From Acct 283, below

In filling out this attachment, a full and complete description of each item and justification for the allocation to Columns C-F and each separate ADIT item will be listed,
Dissimilar items with amounts exceeding $100,000 will be listed separately.

A	B1	B2	B3	C	D	E	F	G	
	Trans-Allegheny Interstate Company								
ADIT-190	Beg of Year Balance p234.18.b	End of Year Balance p234.18.c	End of Year for Est. Average for Final Total	Retail Related	Gas, Prod Or Other Related	Only Transmission Related	Plant Related	Labor Related	JUSTIFICATION
Tax Interest Capitalized	-	1,042,269	521,135			1,042,269	-		Actual amount of tax interest capitalized
Depreciation	-	42	21			42			Depreciation as shown on the tax return
Intercompany Charges	-	102,289	51,145			102,289			Intercompany charges from the AP service company
Worker's Compensation	-	42,230	21,115			42,230			Actual amount of reserve for workers' compensation
Deferred Tax Reclassification	-	778,287	389,144			778,287			Accumulated deferred income taxes reclassified from account 283
	-	-	-						
Subtotal	-	1,965,117	982,559	-	-	1,965,117	-	-	
Less FASB 109 included above									
Less FASB 106 included above									
Total	-	1,965,117	982,559	-	-	1,965,117	-	-	

Instructions for Account 190:

1. ADIT items related only to Retail Related Operations are directly assigned to Column C.
2. ADIT items related only to Non-Electric Operations (e.g., Gas, Water, Sewer) or Production are directly assigned to Column D.
3. ADIT items related only to Transmission are directly assigned to Column E.
4. ADIT items related to Plant and not in Columns C, D & E are directly assigned to Column F.
5. ADIT items related to labor and not in Columns C, D, E & F are directly assigned to Column G.
6. Deferred income taxes arise when items are included in taxable income in different periods than they are included in rates. Therefore, if the item giving rise to the ADIT is not included in the formula, the associated ADIT amount shall be excluded.

PJM TRANSMISSION OWNER

Attachment 1 - Accumulated Deferred Income Taxes (ADIT) Worksheet

A	B1	B2	B3	C	D	E	F	G	
	Trans-Allegheny Interstate Company								
ADIT- 282	**Beg of Year Balance p274.9.b**	**End of Year Balance p275.9.k**	**End of Year for Est. Average for Final Total**	**Retail Related**	**Gas, Prod Or Other Related Related**	**Only Transmission Related Related**	**Plant Related Related**	**Labor Related Related**	**JUSTIFICATION**
Property Related	13,935	366,313	190,124			366,313			Allowance for borrowed funds used during construction (ABFUDC)
	-	-	-			-			
	-	-	-			-			
	-	-	-			-			
	-	-	-			-			
	-	-	-			-			
	-	-	-			-			
	-	-	-			-			
	-	-	-			-			
Subtotal	13,935	366,313	190,124	-	-	366,313	-	-	
Less FASB 109 included above				-	-	-	-	-	
Less FASB 106 included above	-	-	-	-	-	-	-	-	
Total	13,935	366,313	190,124		-	366,313	-	-	

Instructions for Account 282:

1. ADIT items related only to Retail Related Operations are directly assigned to Column C.
2. ADIT items related only to Non-Electric Operations (e.g., Gas, Water, Sewer) or Production are directly assigned to Column D.
3. ADIT items related only to Transmission are directly assigned to Column E.
4. ADIT items related to Plant and not in Columns C, D & E are directly assigned to Column F.
5. ADIT items related to labor and not in Columns C, D, E & F are directly assigned to Column G.
6. Deferred income taxes arise when items are included in taxable income in different periods than they are included in rates. Therefore, if the item giving rise to the ADIT is not included in the formula, the associated ADIT amount shall be excluded.

PJM TRANSMISSION OWNER

Attachment 1 - Accumulated Deferred Income Taxes (ADIT) Worksheet

A	B1	B2	B3	C	D	E	F	G	
	Trans-Allegheny Interstate Company								
ADIT-283	**Beg of Year Balance**	**End of Year Balance**	**End of Year for Est. Average for Final Total**	**Retail Related**	**Gas, Prod Or Other Related**	**Only Transmission Related**	**Plant Related**	**Labor Related**	**JUSTIFICATION**
	p276.19.b	**p277.19.k**							
	-	-	-						
Deferred Tax Reclassification	-	778,287	389,144			778,287			ADIT Balance Sheet Reclassification
	-	-	-						
	-	-	-						
Subtotal	-	778,287	389,144		-	778,287	-	-	
Less FASB 109 included above									
Less FASB 106 included above									
Total	-	778,287	389,144		-	778,287	-	-	

Instructions for Account 283:

1. ADIT items related only to Retail Related Operations are directly assigned to Column C.
2. ADIT items related only to Non-Electric Operations (e.g., Gas, Water, Sewer) or Production are directly assigned to Column D.
3. ADIT items related only to Transmission are directly assigned to Column E.
4. ADIT items related to Plant and not in Columns C, D & E are directly assigned to Column F.
5. ADIT items related to labor and not in Columns C, D, E & F are directly assigned to Column G.

6. Deferred income taxes arise when items are included in taxable income in different periods than they are included in rates. Therefore, if the item giving rise to the ADIT is not included in the formula, the associated ADIT amount shall be excluded.

Trans-Allegheny Interstate Line Company

Attachment 2 - Taxes Other Than Income Worksheet

	Other Taxes	FERC Form No.1 page, line & Col	Amount	Allocator	Allocated Amount
	Plant Related			**Gross Plant Allocator**	
1	Real property (State, Municipal or Local)			100.0000%	$ -
2	Capital Stock Tax	p263.25(i)	3,004	100.0000%	3,004
3	Gross Premium (Insurance) Tax			100.0000%	-
4	Public Utility Realty Tax Act (PURTA), 72 P.S. §8101, *et seq.*			100.0000%	-
5	Corp License	p263.35(i)	288	100.0000%	288
6	Other State License			100.0000%	-
7					-
8	**Total Plant Related**		3,292	100.0000%	3,292
	Labor Related			**Wages & Salary Allocator**	
9	Federal FICA Capitalized				
10	Federal Unemployment	p263.4(i)	2,079		
11	State Unemployment	p263.39(i)	7,774		
12	Accrued FICA	p263.3(i)	143,649		
13					
14	**Total Labor Related**		153,502	100.0000%	153,502
	Other Included			**Gross Plant Allocator**	
15	Miscellaneous				
16	Use and Sales Tax	p263.23(i)	14,541		
17					
18					
19	**Total Other Included**		14,541	100.0000%	14,541
20	**Total Included (Lines 8 + 14 + 19)**		171,335		**171,335** Input to Appendix A, Line 82
	Retail Related Other Taxes to be Excluded				
21	Federal Income Tax	p263.2(i)	1,849,498		
22	Corporate Net Income Tax	p263.33(i)	546,076		
23					
24					
25					
26					
27					
28					
29					
30					
31	**Subtotal, Excluded**		2,395,574		
32	**Total, Included and Excluded (Line 20 + Line 28)**		2,566,909		
33	**Total Other Taxes from p114.14.c**		171,335		
34	Difference (Line 32 - Line 33)		2,395,574		

Criteria for Allocation:

A Other taxes that are incurred through ownership of plant including transmission plant will be allocated based on the Gross Plant Allocator. If the taxes are 100% recovered at retail they shall not be included.

B Other taxes that are incurred through ownership of only general or intangible plant will be allocated based on the Wages and Salary Allocator. If the taxes are 100% recovered at retail they shall not be included.

C Other taxes that are assessed based on labor will be allocated based on the Wages and Salary Allocator.

D Other taxes except as provided for in A, B and C above, that are incurred and (1) are not fully recovered at retail or (2) are directly or indirectly related to transmission service will be allocated based on the Gross Plant Allocator; provided, however, that overheads shall be treated as in footnote B above.

E Excludes prior period adjustments in the first year of the formula's operation and reconciliation for the first year.

Trans-Allegheny Interstate Line Company

Attachment 3 - Revenue Credit Workpaper

Line	Description		Amount	FERC Form No.1 page, line & Col
	Account 454 - Rent from Electric Property			
1	Rent from Electric Property - Transmission Related (Note 3)		-	
2	Total Rent Revenues	(Line 1)	-	
	Account 456 - Other Electric Revenues (Note 1)			
3	Schedule 1A		-	
4	Net revenues associated with Network Integration Transmission Service (NITS) for which the load is not included in the divisor (difference between NITS credits from PJM and PJM NITS charges paid by Transmission Owner) (Note 4)		-	
5	Point to Point Service revenues for which the load is not included in the divisor received by Transmission Owner		-	
6	PJM Transitional Revenue Neutrality (Note 1)			
7	PJM Transitional Market Expansion (Note 1)			
8	Professional Services (Note 3)		-	
9	Revenues from Directly Assigned Transmission Facility Charges (Note 2)		-	
10	Rent or Attachment Fees associated with Transmission Facilities (Note 3)		-	
11	Gross Revenue Credits	(Sum Lines 2-10)	-	
12	Less line 14g		-	
13	Total Revenue Credits	(Line 11 - Line 12)	-	Input to Appendix A, Line 131
	<u>**Revenue Adjustment to determine Revenue Credit**</u>			
14a	Revenues associated with lines 14b-g are to be included in lines 2-10 and total of those revenues entered here		-	
14b	Costs associated with revenues in line 14a		-	
14c	Net Revenues (14a - 14b)		-	
14d	50% Share of Net Revenues (14c / 2)		-	
14e	Costs associated with revenues in line 14a that are included in FERC accounts recovered through the formula times the allocator used to functionalize the amounts in the FERC account to the transmission service at issue.		-	
14f	Net Revenue Credit (14d + 14e)		-	
14g	Line 14a less line 14f		-	
15	Amount offset in line 4 above		-	
16	Total Account 454 and 456			

17 Note 1: All revenues related to transmission that are received as a transmission owner (i.e., not received as a LSE), for which the cost of the service is recovered under this formula, except as specifically provided for elsewhere in this Attachment or elsewhere in the formula will be included as a revenue credit or included in the peak on line 178 of Appendix A.

18 Note 2: If the costs associated with the Directly Assigned Transmission Facility Charges are included in the Rates, the associated revenues are included in the Rates. If the costs associated with the Directly Assigned Transmission Facility Charges are not included in the Rates, the associated revenues are not included in the Rates.

19 Note 3: Ratemaking treatment for the following specified secondary uses of transmission assets: (1) right-of-way leases and leases for space on transmission facilities for telecommunications; (2) transmission tower licenses for wireless antennas; (3) right-of-way property leases for farming, grazing or nurseries; (4) licenses of intellectual property (including a portable oil degasification process and scheduling software); and (5) transmission maintenance and consulting services (including energized circuit maintenance, high-voltage substation maintenance, safety training, transformer oil testing, and circuit breaker testing) to other utilities and large customers (collectively, products). Company will retain 50% of net revenues consistent with Pacific Gas and Electric Company, 90 FERC ¶ 61,314. Note: in order to use lines 14a - 14g, the utility must track in separate subaccounts the revenues and costs associated with each secondary use (except for the cost of the associated income taxes).

20 Note 4: If the facilities associated with the revenues are not included in the formula, the revenue is shown here, but not included in the total above and explained in the Cost Support. For example revenues associated with distribution facilities. In addition Revenues from Schedule 12 of the PJM OATT are not included in the total above to the extent they are credited under Schedule 12 of the PJM OATT.

Trans-Allegheny Interstate Line Company

Attachment 4 - Calculation with Incentive ROE

	Return and Taxes at High End of the range of Reasonableness				
A	Return and Taxes at High End of the range of Reasonableness	(Sum Lines 26 and 33 from below)		2,712,005	Input to Appendix A, Line 140
B	Difference between Base ROE and Incentive ROE			100	

Return Calculation

			Source Reference		
1	Rate Base		Appendix A, Line 46		18,422,788
2	Preferred Dividends	enter positive	Appendix A, Line 84		0
	Common Stock				
3	Proprietary Capital		Appendix A, Line 85		78,829,523
4	Less Accumulated Other Comprehensive Income Account 219		Appendix A, Line 86		0
5	Less Preferred Stock		Appendix A, Line 87		0
6	Less Account 216.1		Appendix A, Line 88		0
7	Common Stock		Appendix A, Line 89		78,829,523
	Capitalization				
8	Long Term Debt		Appendix A, Line 90		0
9	Less Unamortized Loss on Reacquired Debt		Appendix A, Line 91		0
10	Plus Unamortized Gain on Reacquired Debt		Appendix A, Line 92		0
11	Less ADIT associated with Gain or Loss		Appendix A, Line 93		0
12	Total Long Term Debt		Appendix A, Line 94		0
13	Preferred Stock		Appendix A, Line 95		0
14	Common Stock		Appendix A, Line 96		78,829,523
15	Total Capitalization		Appendix A, Line 97		78,829,523
16	Debt %	Total Long Term Debt	Appendix A, Line 98		50%
17	Preferred %	Preferred Stock	Appendix A, Line 99		0%
18	Common %	Common Stock	Appendix A, Line 100		50%
19	Debt Cost	Total Long Term Debt	Appendix A, Line 101		0.0790
20	Preferred Cost	Preferred Stock	Appendix A, Line 102		0.0000
21	Common Cost	Common Stock		12.70%	0.1270
22	Weighted Cost of Debt	Total Long Term Debt (WCLTD)	(Line 16 * 19)		0.0395
23	Weighted Cost of Preferred	Preferred Stock	(Line 17 * 20)		0.0000
24	Weighted Cost of Common	Common Stock	(Line 18 * 21)		0.0635
25	Rate of Return on Rate Base (ROR)		(Sum Lines 22 to 24)		**0.1030**
26	Investment Return = Rate Base * Rate of Return		**(Line 1 * Line 25)**		**1,897,547**

Composite Income Taxes

	Income Tax Rates			
27	FIT=Federal Income Tax Rate		Appendix A, Line 109	35.00%
28	SIT=State Income Tax Rate or Composite		Appendix A, Line 110	9.30%
29	p = percent of federal income tax deductible for state purposes		Appendix A, Line 111	0.00%
30	T	T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =	Appendix A, Line 112	41.05%
31	T/ (1-T)		Appendix A, Line 113	69.62%
32	**Income Tax Component =**	CIT=(T/1-T) * Investment Return * (1-(WCLTD/R)) =		814,458
33	**Total Income Taxes**		**(Line 32)**	**814,458**

Trans-Allegheny Interstate Line Company

Attachment 5 - Cost Support

Plant in Service Worksheet

	Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions			13 Month Balance For Reconciliation	EOY Balance for Estimate	Details: 13 Month Plant Balance For reconciliation						
	Calculation of Transmission Plant In Service	Source		**Total**	**Total**	Black Oak	Wylie Ridge	502 Junction - Territorial Line	500 kV Prexy - 502 Junction	138 kV Prexy - 502 Junction	Project X	**Total**
	December	p206.58.b	For 2006	-		-	-	-	-	-		-
	January	company records	For 2007	-		-	-	-	-	-		-
	February	company records	For 2007	-		-	-	-	-	-		-
	March	company records	For 2007	-		-	-	-	-	-		-
	April	company records	For 2007	79,718		79,718	-	-	-	-		79,718
	May	company records	For 2007	79,718		79,718	-	-	-	-		79,718
	June	company records	For 2007	82,135		82,135	-	-	-	-		82,135
	July	company records	For 2007	82,135		82,135	-	-	-	-		82,135
	August	company records	For 2007	79,815		79,815	-	-	-	-		79,815
	September	company records	For 2007	79,815		79,815	-	-	-	-		79,815
	October	company records	For 2007	457,882		82,153	-	375,730	-	-		457,882
	November	company records	For 2007	460,874		82,153	-	378,721	-	-		460,874
	December	p207.58.g (and notes)	For 2007	59,282,298	59,282,298	44,367,279	12,763,316	2,151,702	-	-		59,282,298
15	**Transmission Plant In Service**			**4,668,030**	**59,282,298**	**3,462,686**	**981,794**	**223,550**	**-**	**-**	**-**	**4,668,030**
				Link to Appendix A, line 15	**Link to Appendix A, line 15**							

	Calculation of Distribution Plant In Service	Source			
	December	p206.75.b	For 2006	-	
	January	company records	For 2007	-	
	February	company records	For 2007	-	
	March\	company records	For 2007	-	
	April	company records	For 2007	-	
	May	company records	For 2007	-	
	June	company records	For 2007	-	
	July	company records	For 2007	-	
	August	company records	For 2007	-	
	September	company records	For 2007	-	
	October	company records	For 2007	-	
	November	company records	For 2007	-	
	December	p207.75.g	For 2007	-	-
	Distribution Plant In Service			-	-
	Calculation of Intangible Plant In Service	Source			
	December	p204.5.b	For 2006	-	
	December	p205.5.g	For 2007	-	-
18	**Intangible Plant In Service**			-	-
				Link to Appendix A, line 18	**Link to Appendix A, line 18**
	Calculation of General Plant In Service	Source			
	December	p206.99.b	For 2006	-	
	December	p207.99.g	For 2007	-	-
18	**General Plant In Service**			-	-
				Link to Appendix A, line 18	**Link to Appendix A, line 18**
	Calculation of Production Plant In Service	Source			
	December	p204.46b	For 2006	-	
	January	company records	For 2007	-	
	February	company records	For 2007	-	
	March\	company records	For 2007	-	
	April	company records	For 2007	-	
	May	company records	For 2007	-	
	June	company records	For 2007	-	
	July	company records	For 2007	-	
	August	company records	For 2007	-	
	September	company records	For 2007	-	
	October	company records	For 2007	-	
	November	company records	For 2007	-	
	December	p205.46.g	For 2007	-	-
	Production Plant In Service			-	-
6	**Total Plant In Service**	Sum of averages above		**4,668,030**	**59,282,298**
				Link to Appendix A, line 6	**Link to Appendix A, line 6**

Trans-Allegheny Interstate Line Company

Attachment 5 - Cost Support

Accumulated Depreciation Worksheet

	Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions			13 Month Balance For Reconciliation	EOY Balance for Estimate	Details: 13 Month Balance For reconciliation — Black Oak	Wylie Ridge	502 Junction - Territorial Line	500 kV Prexy - 502 Junction	138 kV Prexy - 502 Junction	Project X	Total
	Calculation of Transmission Accumulated Depreciation	Source										
	December	Prior year FERC Form 1 p219.25.b	For 2006	-		-	-	-	-	-		-
	January	company records	For 2007	-		-	-	-	-	-		-
	February	company records	For 2007	-		-	-	-	-	-		-
	March\	company records	For 2007	-		-	-	-	-	-		-
	April	company records	For 2007	-		-	-	-	-	-		-
	May	company records	For 2007	-		-	-	-	-	-		-
	June	company records	For 2007	-		-	-	-	-	-		-
	July	company records	For 2007	-		-	-	-	-	-		-
	August	company records	For 2007	-		-	-	-	-	-		-
	September	company records	For 2007	-		-	-	-	-	-		-
	October	company records	For 2007	-		-	-	-	-	-		-
	November	company records	For 2007	51		-	-	51	-	-		51
	December	p219.25.b	For 2007	102	102	-	-	102	-	-		102
23	**Transmission Accumulated Depreciation**			**12**	**102**	**-**	**-**	**12**	**-**	**-**	**-**	**12**
				Link to Appendix A, line 23	**Link to Appendix A, line 23**							

				13 Month Balance For Reconciliation	EOY Balance for Estimate
	Calculation of Distribution Accumulated Depreciation	Source			
	December	Prior year FERC Form 1 p219.26.b	For 2006	-	
	January	company records	For 2007	-	
	February	company records	For 2007	-	
	March\	company records	For 2007	-	
	April	company records	For 2007	-	
	May	company records	For 2007	-	
	June	company records	For 2007	-	
	July	company records	For 2007	-	
	August	company records	For 2007	-	
	September	company records	For 2007	-	
	October	company records	For 2007	-	
	November	company records	For 2007	-	
	December	p219.26.b	For 2007	-	-
	Distribution Accumulated Depreciation			-	-
	Calculation of Intangible Accumulated Depreciation	Source			
	December	Prior year FERC Form 1 p200.21.b	For 2006		
	December	p200.21b	For 2007	-	-
25	**Accumulated Intangible Depreciation**			-	-
				Link to Appendix A, line 25	**Link to Appendix A, line 25**
	Calculation of General Accumulated Depreciation	Source			
	December	Prior year FERC Form 1 p219.28b	For 2006		
	December	p219.28.b	For 2007	-	-
24	**Accumulated General Depreciation**			-	-
				Link to Appendix A, line 24	**Link to Appendix A, line 24**
	Calculation of Production Accumulated Depreciation	Source			
	December	Prior year FERC Form 1 p219.20.b-	For 2006	-	
	January	company records	For 2007	-	
	February	company records	For 2007	-	
	March\	company records	For 2007	-	
	April	company records	For 2007	-	
	May	company records	For 2007	-	
	June	company records	For 2007	-	
	July	company records	For 2007	-	
	August	company records	For 2007	-	
	September	company records	For 2007	-	
	October	company records	For 2007	-	
	November	company records	For 2007	-	
	December	p219.20.b thru 219.24.b	For 2007	-	-
	Production Accumulated Depreciation			-	-
8	**Total Accumulated Depreciation**	Sum of averages above		**12**	**102**
				Link to Appendix A, line 8	**Link to Appendix A, line 8**

Trans-Allegheny Interstate Line Company

Attachment 5 - Cost Support

Electric / Non-electric Cost Support

Link to Appendix A, line #s, Descriptions, Notes, Form 1 Page #s and Instructions				Form 1 Amount	Electric Portion	Non-electric Portion	Details
				Beg of year	End of Year (for estimate)	Average of Beginning and Ending Balances	
	Materials and Supplies						
40	Transmission Materials & Supplies		p227.8	-	-	-	
37	Undistributed Stores Expense		p227.16	-	-	-	
	Allocated General Expenses						
51	Plus Property Under Capital Leases	0	p200.4.c	-	-	-	

Transmission / Non-transmission Cost Support

Link to Appendix A, line #s, Descriptions, Notes, Form 1 Page #s and Instructions			Beg of year	End of Year (for estimate)	Average of Beginning and Ending Balances	Details
34	Transmission Related Land Held for Future Use	Total	-	-	-	Enter Details Here
		Non-transmission Related	-	-	-	
		Transmission Related	-	-	-	

CWIP & Expensed Lease Worksheet

Link to Appendix A, line #s, Descriptions, Notes, Form 1 Page #s and Instructions				Beg of year	CWIP In Form 1 Amount	Expensed Lease in Form 1 Amount	Details
	Plant Allocation Factors						
6	Electric Plant in Service	(Note B)	Attachment 5	-	-	-	
	Plant In Service						
15	Transmission Plant In Service	(Note B)	Attachment 5	-	-	-	
	Accumulated Depreciation						
23	Transmission Accumulated Depreciation	(Note B)	Attachment 5	-	-	-	

Trans-Allegheny Interstate Line Company

Attachment 5 - Cost Support

Pre-Commercial Costs Capitalized

Link to Appendix A, line #s, Descriptions, Notes, Form 1 Page #s and Instructions	EOY for Estimate and BOY for Final	Amortization Amount (Over 4 Years)	Calculated End of Year Balance	Average of Beginning and Ending Balances (for estimate and reconciliation)
35 Unamortized Capitalized Pre-Commercial Costs	$ 2,270,744	$ 567,686	$ 1,703,058	$ 1,986,901

EPRI Dues Cost Support

Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions			Beg of year	EPRI Dues	Details
Allocated General & Common Expenses					
58 Less EPRI Dues	(Note D)	p352 & 353			Enter Details Here

Regulatory Expense Related to Transmission Cost Support

Link to Appendix A, line #s, Descriptions, Notes, Form 1 Page #s and Instructions			Form 1 Amount	Transmission Related	Non-transmission Related		Details
Directly Assigned A&G							
62 Regulatory Commission Exp Account 928	(Note G)	p323.189.b	-	-	-	Link to Appendix A, line 66	Enter Details Here

Safety Related Advertising Cost Support

Link to Appendix A, line #s, Descriptions, Notes, Form 1 Page #s and Instructions			Form 1 Amount	Safety Related	Non-safety Related		Details
Directly Assigned A&G							
66 General Advertising Exp Account 930.1	(Note F)	p323.191.b	-	-	-	Link to Appendix A, line 70	Enter Details Here

MultiState Workpaper

Link to Appendix A, line #s, Descriptions, Notes, Form 1 Page #s and Instructions		State 1	State 2	State 3	State 4	State 5	Details
Income Tax Rates							
110 SIT=State Income Tax Rate or Composite	(Note I)	Composite 9.30%					

Education and Out Reach Cost Support

Link to Appendix A, line #s, Descriptions, Notes, Form 1 Page #s and Instructions			Form 1 Amount	Education & Outreach	Other	Details
Directly Assigned A&G						
63 General Advertising Exp Account 930.1	(Note J)	p323.191.b	-	-	-	Enter Details Here

Trans-Allegheny Interstate Line Company

Attachment 5 - Cost Support

Excluded Plant Cost Support

Link to Appendix A, line #s, Descriptions, Notes, Form 1 Page #s and Instructions			Excluded Transmission Facilities	Description of the Facilities
	Adjustment to Remove Revenue Requirements Associated with Excluded Transmission Facilities			
126	Excluded Transmission Facilities	(Note L)		General Description of the Facilities
	Step-Up Facilities		-	
	Instructions:		Enter $	
1	Remove all investment below 69 kV or generator step up transformers included in transmission plant in service that are not a result of the RTEP Process			
2	If unable to determine the investment below 69kV in a substation with investment of 69 kV and higher as well as below 69 kV,		Or	
	the following formula will be used:	Example	Enter $	
A	Total investment in substation	1,000,000		
B	Identifiable investment in Transmission (provide workpapers)	500,000		
C	Identifiable investment in Distribution (provide workpapers)	400,000		
D	Amount to be excluded (A x (C / (B + C)))	444,444		
				Add more lines if necessary

Prepayments

Link to Appendix A, line #s, Descriptions, Notes, Form 1 Page #s and Instructions			Beg of year	End of Year	Average of Beginning and Ending Balances	Allocation	Transmission Related	Details
36	Prepayments				Enter $		Amount	
	Prepayments	Prepaid Insurance	-	35,363	17,682	100%	17,682	
	Prepaid Pensions if not included in Prepayments		-	-	-	100%	-	
	Total Prepayments		-	**35,363**	17,682		**17,682**	

Trans-Allegheny Interstate Line Company

Attachment 5 - Cost Support

Detail of Account 566 Miscellaneous Transmission Expenses

Link to Appendix A, line #s, Descriptions, Notes, Form 1 Page #s and Instructions			Total
70	Amortization Expense on Pre-Commercial Cost		$ 567,686
71	Pre-Commercial Expense		734,168
72	Miscellaneous Transmission Expense		-
	Total Account 566 Miscellaneous Transmission Expenses	p.321	$ 1,301,854
	Net Revenue Requirement		
149	Facility Credits under Section 30.9 of the PJM OATT		-

Details

Summary of Pre-Commercial Expenses

Cost Element Name	Total
Labor & Overhead (1)	398,966
Miscellaneous (2)	6,727
Outside Services Legal (3)	(38,212)
Outside Services Other (4)	232,415
Outside Services Rates (5)	48,400
Advertising (6)	53,605
Travel, Lodging and Meals (7)	32,267
Total	734,168

(1) Labor & overhead amount includes costs allocated to preparation of the preliminary survey and investigation.
(2) Miscellaneous amount includes rental of volunteer fire department facilities for open houses, Fed EX fees for various mailings from Legal, Procurement, Transmission & Finance, fees for various conference calls and PJM application fee.
(3) Outside legal services includes the cost for research and preparation of the filing to determine incentive rate availability.
(4) Other services other includes fees for website development, media relations services, campaign management, open houses and research services.
(5) Outside services rates includes the advice of a rate consultant regarding rate design.
(6) Advertising includes newspaper and other media announcements of public scoping meetings related to the proposed project.
(7) Travel, lodging and meals are the direct expenses for Allegheny staff to attend the scoping meetings.

Depreciation Rates

TRANSMISSION PLANT		Life		Survivor Curve	Net Salvage Percent	Accrual Rate (Annual) Percent	Black Oak	Wylie Ridge		502 Junction - Territorial Line	500 kV Prexy - 502 Junction	138 kV Prexy - 502 Junction	Project X	Total
350.2	Land & Land Rights - Easements	70	-	R4	0	1.43	-	-	-	-	-	-		-
352	Structures & Improvements	50	-	R3	(10)	2.20	-	-	-	-	-	-		-
	SVC	35	-			2.86	-	-	-	-	-	-		-
353	Station Equipment													
	Other	50	-	R2	(5)	2.10	-		-	102	-	-		102
	SVC	Note 1	-	80 R2 - 35-yr truncation		2.96	-	-	-	-	-	-		-
	SCADA	15	-	S3	0	6.67	-	-	-	-	-	-		-
354	Towers & Fixtures	65	-	R4	(25)	1.92	-	-	-	-	-	-		-
355	Poles & Fixtures	55	-	R2.5	(20)	2.18	-	-	-	-	-	-		-
							-	-	-	-	-	-		
356	Overhead Conductors & Devices						-	-	-	-	-	-		
	Other	50	-	R2.5	(40)	2.80	-	-	-	-	-	-		-
	Clearing	70	-	R4	0	1.43	-	-	-	-	-	-		-
							-	-	-	-	-	-		
357	Underground conduit	55	-	S3	(5)	1.91	-	-	-	-	-	-		-
358	Underground conductor and devices	45	-	R3	(5)	2.33	-	-	-	-	-	-		-
	SVC	35				2.86	-	-	-	-	-	-		-
Total Depreciation Expense (must tie to p336.7.:	102						-	-	-	**102**	-	-	-	**102**

Note 1: Depreciation rate is based on an 80 R2 survivor curve with a 35-year truncation.
These depreciation rates will not change absent the appropriate filing at FEF

PBOP Expenses

	1 Total PBOP expenses	22,856,433
	2 Amount relating to retired personnel	8,786,372
	3 Amount allocated on FTEs	14,070,061
	4 Number of FTEs for Allegheny	4,408
	5 Cost per FTE	3,192
	6 TrAILCo FTEs (labor not capitalized) current year	5.06
	7 TrAILCo PBOP Expense for base year	16,145
	8 TrAILCo PBOP Expense in Account 926 for current year	42,210
57	9 PBOP Adjustment for Appendix A, Line 57	(26,065)

Lines 1-5 cannot change absent approval or acceptance by FERC in a separate proceeding.

Trans-Allegheny Interstate Line Company

Attachment 5a - Pre-Commercial Costs and CWIP

Step 1 Totals reported below are by project with the amounts to be expensed reported separately from those to be deferred and amortized (note, deferred costs related to 2006 include AFUDC).

For Forecasting purposes, Pre-Commercial expenses will be estimated. Total deferred and amortized Pre-commercial costs will be the actual amount agreeing to FERC Form 1 and Attachment 5.

Step 2 For each project, where CWIP is to be recovered in rate base, CWIP will be estimated and the totals reported below by project. For the Reconciliation, for each project where CWIP is to be recovered in rate base the CWIP will be itemized by project below. Additionally, the amount of AFUDC that would have been capitalized for projects where CWIP is included in rate base will be reported in the FERC Form No. 1.

Step 3 For the Reconciliation, the total additions to plant in service for that year will be summarized by project to demonstrate no Pre-Commercial costs expensed were included in the additions to plant in service and AFUDC on projects where CWIP was recovered in rate base was included in the additions to plant in service. The Pre-commercial expenses are actual expenses incurred for the reconciliation year. Total deferred and amortized Pre-commercial costs will be the actual amount agreeing to FERC Form 1 and Attachment 5.

	Column A	Column B	Column C Pre-Commercial Costs	Column D		Column E CWIP	Column F	Column G
Step 1	**For Estimate:**	Expensed (Estimated)	Deferred	Amount of Deferred Amortized in Year	**Estimate Step 2**	Average of 13 Monthly Balances		
	Prexy - 502 Junction 138 kV (CWIP)	268,358		60,937				
	Prexy - 502 Junction 500 kV (CWIP)	345,667		78,492				
	502 Junction - Territorial Line (CWIP)	1,885,975		428,257				
	Total	2,500,000	2,270,744	567,686		-		

		Pre-Commercial Costs						
Step 3	**For Reconciliation:**	Expensed (Actual)	Deferred	Amount of Deferred Amortized in Year	**For Reconciliation Step 2**	CWIP	AFUDC In CWIP	AFUDC (If CWIP was not in Rate Base)
	Prexy - 502 Junction 138 kV (CWIP)							
	1	78,808	243,749	60,937		4,808,804	-	105,308
	2	-		-				
	3	-		-				
	4	-		-				
	...							
	Total	78,808	243,749	60,937		4,808,804	-	105,308
	Prexy - 502 Junction 500 kV (CWIP)							
	1	101,511	313,969	78,492		5,244,579	-	182,811
	2	-		-				
	3	-		-				
	4	-		-				
	...							
	Total	101,511	313,969	78,492		5,244,579	-	182,811
	502 Junction - Territorial Line (CWIP)							
	1	553,849	1,713,026	428,257		20,651,884	-	813,877
	2	-		-				
	3	-		-				
	4	-		-				
	...							
	Total	553,849	1,713,026	428,257		20,651,884	-	813,877
	Total Additions to Plant In Service (sum of the above for each project)					-		
	Total Additions to Plant in Service reported on pages 200-204 of the Form No. 1							
	Difference (must be zero)					-		

Notes:

1 Small projects may be combined into larger projects where rate treatment is consistent. Pre-Commercial costs benefiting multiple projects will be allocated to projects based on the estimated plant in service of each project.

Allocation of Pre-Commercial Costs	Plant in Service (Estimated 2/12/2008)	Allocation
Prexy - 502 Junction 138 kV (CWIP)	94,140,000	0.10734
Prexy - 502 Junction 500 Kv (CWIP)	121,260,000	0.13827
502 Junction - Territorial Line (CWIP)	661,600,000	0.75439
Total	877,000,000	1.00000

2 Column D is the total CWIP balance including any AFUDC, Column E is the AFUDC if any in Column D, and Column F is the AFUDC that would have been in Column E if CWIP were not recovered in rate base.

Trans-Allegheny Interstate Line Company

Attachment 6 - Estimate and Reconciliation Worksheet

Step	Month	Year	Action
Exec Summary			
1	April	Year 2	TO populates the formula with Year 1 data
2	April	Year 2	TO estimates all transmission Cap Adds and CWIP for Year 2 based on each project's cost using the average of 13 monthly balances. Cap Adds are the projects expected to be in service in Year 2.
3	April	Year 2	TO adds Cap Adds and CWIP to plant in service in Formula (Appendix A, Lines 16 and 33)
4	May	Year 2	Post results of Step 3 on PJM web site
5	June	Year 2	Results of Step 3 go into effect
6	April	Year 3	TO estimates all transmission Cap Adds and CWIP during Year 3 based each project's cost using the average of 13 monthly balances. Cap Adds are expected be in service in Year 3.
7	April	Year 3	Reconciliation - TO calculates Reconciliation by populating the 13 monthly plant balances and beginning and end of year balances for the other rate base items and the 13 monthly averages for CWIP in Reconciliation (adjusted to include any Reconciliation amount from prior year).
8	April	Year 3	Reconciliation - TO adds the difference between the Reconciliation in Step 7 and the forecast in Step 5 with interest to the result of Step 7 (this difference is also added to Step 7 in the subsequent year)
9	May	Year 3	Post results of Step 8 on PJM web site
10	June	Year 3	Results of Step 8 go into effect

Reconciliation Details

1 April Year 2 TO populates the formula with Year 1 data

Rev Req based on Year 1 data

Must run Appendix A to get this number (without any cap adds in Appendix A line 16 and without CWIP in Appendix A line 33)

2 April Year 2 TO estimates all transmission Cap Adds and CWIP for Year 2 based on each project's cost using the average of 13 monthly balances. Cap Adds are the projects expected to be in service in Year 2.

	(A)	(B)	(C)	(D)	(E)	(F)
	Other Projects PIS (monthly additions)	Black Oak (monthly additions)	Wylie Ridge (monthly additions)	502 Junction - Territorial Line (monthly additions)	500 kV Prexy - 502 Junction (monthly additions)	138 kV Prexy - 502 Junction (monthly additions)
		(in service)	(in service)	CWIP	CWIP	CWIP
Dec (Prior Year CWIP) p216.b.43				29,078	3,120	2,421
Jan 2007		-	-	100,000	168,900	131,100
Feb		-	-	100,000	168,900	131,100
Mar		-	-	1,900,000	225,200	174,800
Apr		-	-	2,200,000	619,300	480,700
May		-	-	2,200,000	619,300	480,700
Jun		-	-	2,200,000	619,300	480,700
Jul		-	-	2,200,000	675,600	524,400
Aug		-	-	2,100,000	619,300	480,700
Sep		-	-	2,000,000	675,600	524,400
Oct		-	7,618,489	4,100,000	788,200	611,800
Nov		-	-	3,200,000	788,200	611,800
Dec		49,528,583	7,329,602	3,200,000	788,200	611,800
Total	-	49,528,583	14,948,091	25,529,078	6,759,120	5,246,421

New Transmission Plant Additions for Year 2 (13 month average balance)

Month End Balances

	Other Projects PIS (monthly additions)	Black Oak (monthly balance)	Wylie Ridge (monthly balance)	502 Junction - Territorial Line (monthly balance)	500 kV Prexy - 502 Junction (monthly balance)	138 kV Prexy - 502 Junction (monthly balance)
		(in service)	(in service)	CWIP	CWIP	CWIP
Dec (Prior Year CWIP) p216.b.43				29,078	3,120	2,421
Jan 2007		-	-	129,078	172,020	133,521
Feb		-	-	229,078	340,920	264,621
Mar		-	-	2,129,078	566,120	439,421
Apr		-	-	4,329,078	1,185,420	920,121
May		-	-	6,529,078	1,804,720	1,400,821
Jun		-	-	8,729,078	2,424,020	1,881,521
Jul		-	-	10,929,078	3,099,620	2,405,921
Aug		-	-	13,029,078	3,718,920	2,886,621
Sep		-	-	15,029,078	4,394,520	3,411,021
Oct		-	7,618,489	19,129,078	5,182,720	4,022,821
Nov		-	7,618,489	22,329,078	5,970,920	4,634,621
Dec		49,528,583	14,948,091	25,529,078	6,759,120	5,246,421
Total		49,528,583	30,185,069	128,078,014	35,622,155	27,649,878
Average 13 Month Balance		3,809,891	2,321,928	9,852,155	2,740,166	2,126,914
		(Appendix A, Line 16)	(Appendix A, Line 16)	(Appendix A, Line 33)	(Appendix A, Line 33)	(Appendix A, Line 33)

3 April Year 2 TO adds Cap Adds and CWIP to plant in service in Formula (Appendix A, Lines 16 and 33)

4 May Year 2 Post results of Step 3 on PJM web site

Total Revenue Requirement	Black Oak (monthly additions)	Wylie Ridge (monthly additions)	502 Junction - Territorial Line (monthly additions)	500 kV Prexy - 502 Junction (monthly additions)	138 kV Prexy - 502 Junction (monthly additions)
$ 7,010,015	444,422	401,037	4,330,967	1,032,310	801,279

5 June Year 2 Results of Step 3 go into effect

6 April Year 3 TO estimates all transmission Cap Adds and CWIP during Year 3 based each project's cost using the average of 13 monthly balances. Cap Adds are expected be in service in Year 3.

	(A) Other Projects PIS (monthly additions)	(B) Black Oak (monthly additions) (in service)	(C) Wylie Ridge (monthly additions) (in service)	(D) 502 Junction - Territorial Line (monthly additions) CWIP	(E) 500 kV Prexy - 502 Junction (monthly additions) CWIP	(F) 138 kV Prexy - 502 Junction (monthly additions) CWIP
Dec (Prior Year CWIP) p216.b.43					-	-
Jan 2007		-	-	-	-	-
Feb		-	-	-	-	-
Mar		-	-	-	-	-
Apr		-	-	-	-	-
May		-	-	-	-	-
Jun		-	-	-	-	-
Jul		-	-	-	-	-
Aug		-	-	-	-	-
Sep		-	-	-	-	-
Oct		-	-	-	-	-
Nov		-	-	-	-	-
Dec		-	-	-	-	-
Total	-	-	-	-	-	-
New Transmission Plant Additions for Year 2 (13 month average balance)						

Month End Balances

	Other Projects PIS (Monthly additions)	Black Oak (monthly balance) (in service)	Wylie Ridge (monthly balance) (in service)	502 Junction - Territorial Line (monthly balance) CWIP	500 kV Prexy - 502 Junction (monthly balance) CWIP	138 kV Prexy - 502 Junction (monthly balance) CWIP
Dec (Prior Year CWIP) p216.b.43		-	-	-	-	-
Jan 2007		-	-	-	-	-
Feb		-	-	-	-	-
Mar		-	-	-	-	-
Apr		-	-	-	-	-
May		-	-	-	-	-
Jun		-	-	-	-	-
Jul		-	-	-	-	-
Aug		-	-	-	-	-
Sep		-	-	-	-	-
Oct		-	-	-	-	-
Nov		-	-	-	-	-
Dec		-	-	-	-	-
Total		-	-	-	-	-
New Transmission Plant Additions for Year 2 (13 month average balance)		-	-	-	-	-

Total Revenue Requirement	Black Oak (monthly additions)	Wylie Ridge (monthly additions)	502 Junction - Territorial Line (monthly additions)	500 kV Prexy - 502 Junction (monthly additions)	138 kV Prexy - 502 Junction (monthly additions)
-	-	-	-	-	-

7 April Year 3 Reconciliation - TO calculates Reconciliation by populating the 13 monthly plant balances and beginning and end of year balances for the other rate base items and the 13 monthly averages for CWIP in Reconciliation (adjusted to include any Reconciliation amount from prior year).

	(A) 502 Junction - Territorial Line (monthly additions) CWIP	(B) 500 kV Prexy - 502 Junction (monthly additions) CWIP	(C) 138 kV Prexy - 502 Junction (monthly additions) CWIP	(D) Wylie Ridge (monthly additions) (in service)		Month End Balances: 502 Junction - Territorial Line (monthly balance) CWIP	500 kV Prexy - 502 Junction (monthly balance) CWIP	138 kV Prexy - 502 Junction (monthly balance) CWIP	Wylie Ridge (monthly additions)	Total	
Dec (Prior Year CWIP) p216.b.43	29,078	2,928	2,613			29,078	2,928	2,613	0		
Jan 2007	0	0	0			29,078	2,928	2,613	0		
Feb	4,378	0	0			33,455	2,928	2,613	0		
Mar	151,079	0	60			184,534	2,928	2,673	0		
Apr	2,341,369	564,082	218,794			2,525,903	567,010	221,468	0		
May	1,647,451	101,022	42,273			4,173,354	668,032	263,741	0		
Jun	2,481,436	494,537	234,017			6,654,790	1,162,569	497,759	0		
Jul	1,975,834	435,348	239,276			8,630,624	1,597,917	737,034	0		
Aug	2,387,279	644,797	421,307			11,017,903	2,242,714	1,158,342	0		
Sep	2,529,975	702,818	461,676			13,547,878	2,945,532	1,620,017	0		
Oct	2,087,239	744,465	667,299			15,635,117	3,689,997	2,287,316	0		
Nov	2,458,043	828,367	566,151			18,093,159	4,518,363	2,853,467	0		
Dec	2,558,724	726,216	1,955,336	197,754		20,651,884	5,244,579	4,808,804	197,754		
Total	20,651,884	5,244,579	4,808,804	197,754		101,206,758	22,648,425	14,458,461	197,754		
					Average 13 Month Balance	7,785,135	1,742,187	1,112,189	15,212	10,654,723	Input to Appendix A, line 33

Result of Formula for Reconciliation

Total Revenue Requirement	Black Oak (monthly additions)	Wylie Ridge (monthly additions)	502 Junction - Territorial Line (monthly additions)	500 kV Prexy - 502 Junction (monthly additions)	138 kV Prexy - 502 Junction (monthly additions)	
$ 8,410,662	1,608,748	453,038	4,702,999	989,415	656,463	Must run Appendix A with cap adds in Appendix A, line 16 and CWIP in Appendix line 33

8 April Year 3 Reconciliation - TO adds the difference between the Reconciliation in Step 7 and the forecast in Step 5 with interest to the result of Step 7 (this difference is also added to Step 7 in the subsequent year)

The Reconciliation in Step 8		The forecast in Prior Year		
8,410,662	-	7,010,015	=	1,400,647

<Note: for the first rate year, divide this reconciliation amount by 12 and multiply by the number of months and fractional months the rate was in effect.

Interest on Amount of Refunds or Surcharges

Interest 35.19a for March Current Yr 0.6600%

Month	Yr	1/12 of Step 9	Interest 35.19a for March Current Yr	Months	Interest	Surcharge (Refund) Owed
Jun	Year 1	116,721	0.6600%	11.5	8,859	125,580
Jul	Year 1	116,721	0.6600%	10.5	8,089	124,809
Aug	Year 1	116,721	0.6600%	9.5	7,318	124,039
Sep	Year 1	116,721	0.6600%	8.5	6,548	123,269
Oct	Year 1	116,721	0.6600%	7.5	5,778	122,498
Nov	Year 1	116,721	0.6600%	6.5	5,007	121,728
Dec	Year 1	116,721	0.6600%	5.5	4,237	120,958
Jan	Year 2	116,721	0.6600%	4.5	3,467	120,187
Feb	Year 2	116,721	0.6600%	3.5	2,696	119,417
Mar	Year 2	116,721	0.6600%	2.5	1,926	118,647
Apr	Year 2	116,721	0.6600%	1.5	1,156	117,876
May	Year 2	116,721	0.6600%	0.5	385	117,106
Total		1,400,647				1,456,113

		Balance	Interest	Amort	Balance
Jun	Year 2	1,456,113	0.6600%	126,611	1,339,112
Jul	Year 2	1,339,112	0.6600%	126,611	1,221,339
Aug	Year 2	1,221,339	0.6600%	126,611	1,102,789
Sep	Year 2	1,102,789	0.6600%	126,611	983,456
Oct	Year 2	983,456	0.6600%	126,611	863,336
Nov	Year 2	863,336	0.6600%	126,611	742,423
Dec	Year 2	742,423	0.6600%	126,611	620,712
Jan	Year 3	620,712	0.6600%	126,611	498,197
Feb	Year 3	498,197	0.6600%	126,611	374,874
Mar	Year 3	374,874	0.6600%	126,611	250,737
Apr	Year 3	250,737	0.6600%	126,611	125,781
May	Year 3	125,781	0.6600%	126,611	(0)
Total with interest				1,519,334	

The difference between the Reconciliation in Step 8 and the forecast in Prior Year with interest	1,519,334	Input to Appendix A, Line 147
Rev Req based on Year 2 data with estimated Cap Adds for Year 3 (Step 8)	$ -	
Revenue Requirement for Year 3	1,519,334	

Reconciliation amount by Project

Total Reconciliation Amount	Black Oak (monthly additions)	Wylie Ridge (monthly additions)	502 Junction - Territorial Line (monthly additions)	500 kV Prexy - 502 Junction (monthly additions)	138 kV Prexy - 502 Junction (monthly additions)
1,519,334	1,262,987	56,407	403,557	(46,530)	(157,087)

9 May Year 3 Post results of Step 8 on PJM web site

$ 1,519,334 Post results of Step 3 on PJM web site

10 June Year 3 Results of Step 8 go into effect

$ 1,519,334

Trans-Allegheny Interstate Line Company

Attachment 7 - Transmission Enhancement Charge Worksheet

1 **Revenue Requirement By Project**

		Formula Line		
2	**Fixed Charge Rate (FCR) if not a CIAC**			
3	A	137	FCR without Depreciation and Pre-Commercial Costs	45.4398%
4	B	145	FCR with Incentive ROE without Depreciation and Pre-Commercial	46.4595%
5	C		Line B less Line A	1.0197%
6	**FCR if a CIAC**			
7	D	138	FCR without Depreciation, Return, nor Income Taxes	37.2565%

8 **The FCR resulting from Formula in a given year is used for that year only.**
9 **Therefore actual revenues collected in a year do not change based on cost data for subsequent years**

				PJM Upgrade ID: b0321.2; b0321.3	**PJM Upgrade ID: b0321.1**	**PJM Upgrade ID: b0328.2; b0347.1; b0347.2; b0347.3; b0347.4**
10		Details		Prexy - 502 Junction 138 kV (CWIP + Plant In Service)	Prexy - 502 Junction 500 kV (CWIP+ Plant In Service)	502 Junction - Territorial Line (CWIP + Plant In Service)
11	"Yes" if a project under PJM OATT Schedule 12, otherwise "No"	Schedule 12	(Yes or No)	Yes	Yes	Yes
12	"Yes" if the customer has paid a lump sum payment in the amount of the investment on line 29, Otherwise "No"	CIAC	(Yes or No)	No	No	No
13	Input the allowed ROE	Allowed ROE		12.70%	12.70%	12.70%
14	From line 3 above if "No" on line 12 and From line 7 above if "Yes" on line 12	FCR without Incentive ROE		45.4398%	45.4398%	45.4398%
15	If line 13 equals 12.7%, then line 4, if line 13 equals 11.7% then line 3, and if line 12 is "Yes" then line 7	FCR for This Project		46.4595%	46.4595%	46.4595%
16	forecast of CWIP or Cap Adds. reconciliation – Average of 13 month prior year net plant balances plus prior year 13-mo CWIP balances.	Investment		1,112,189	1,742,187	8,008,674
17	Annual Depreciation Exp from Attachment 5			-	-	102

Line			Invest Yr	Return	Depreciation	Pre-Commercial Exp.	**Reconciliation amount**	Revenue	Return	Depreciation	Pre-Commercial Exp.	**Reconciliation amount**	Revenue	Return	Depreciation	Pre-Commercial Exp.	**Reconciliation amount**	Revenue
18																		
19	See Calculations for each item below	Wo Incentive ROE	2007	505,377	-	139,745	-	645,122	791,647	-	180,003	-	971,650	3,639,128	102	982,106	-	4,621,336
20	See Calculations for each item below	W Incentive ROE	2007	516,718	-	139,745	-	656,463	809,412	-	180,003	-	989,415	3,720,792	102	982,106	-	4,702,999

For Plant in Service
"Pre-Commercial Exp" is equal to the amount of pre-commercial expense on Attachment 5a for each project expensed in year and amortized in year.
Revenue is equal to the "Return" ("Investment" times FCR) plus "Depreciation" plus "Pre-Commercial Exp" plus prior year "Reconciliation amount"
"Reconciliation Amount" is created in the reconciliation in Attachment 6 and included in the forecasted revenue requirement.

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Line	Description	PJM Upgrade ID: b0218	PJM Upgrade ID: b0216	
10		Wylie Ridge Transformer (Plant In Service)	Black Oak (SVC) Dynamic Reactive Device (Plant In Service)	Project X
11	"Yes" if a project under PJM OATT Schedule 12, otherwise "No"	Yes	Yes	Yes
12	"Yes" if the customer has paid a lump sum payment in the amount of the investment on line 29, Otherwise "No"	No	No	No
13	Input the allowed ROE	11.70%	12.70%	11.70%
14	From line 3 above if "No" on line 12 and From line 7 above if "Yes" on line 12	45.4398%	45.4398%	45.4398%
15	If line 13 equals 12.7%, then line 4, if line 13 equals 11.7% then line 3, and if line 12 is "Yes" then line 7	45.4398%	46.4595%	45.4398%
16	forecast of CWIP or Cap Adds. reconciliation – Average of 13 month prior year net plant balances plus prior year 13-mo CWIP balances.	997,005	3,462,686	-
17	Annual Depreciation Exp from Attachment 5	-	-	

Line	Description	Return	Depreciation	Reconciliation amount	Revenue	Return	Depreciation	Reconciliation amount	Revenue	Return	Depreciation	Reconciliation amount	Revenue	Total	Incentive Charged	Revenue Credit	
18																	$ 146,078
19	See Calculations for each item below	453,038	-	-	453,038	1,573,439	-	-	1,573,439	-			-	8,264,584		8,264,584	**Ax A Line 148**
20	See Calculations for each item below	453,038	-	-	453,038	1,608,748	-	-	1,608,748	-			-	8,410,662	8,410,662		

For Plant in Service
"Pre-Commercial Exp" is equal to the amount of pre-comme
Revenue is equal to the "Return" ("Investment" times FCR)
"Reconciliation Amount" is created in the reconciliation in At

Template for Annual Information Filings with Formula Rate Debt Cost Disclosure and True-Up

Attachment 8, page 1, Table 1 and 2

Template for Annual Information Filings with Formula Rate Debt Cost Disclosure and True-Up

TABLE 1: Summary Cost of Long Term Debt

CALCULATION OF COST OF DEBT/Hypothetical Example

YEAR ENDED	12/31/2014

	t=N	(a) Issue Date	(b) Maturity Date	(c) ORIGINAL ISSUANCE	(d) Net Proceeds At Issuance	(e) Net Amount Outstanding at t=N	(f) Months Outstanding at t=N	(g) Average Net Outstanding in Year* z*	(h) Weighted Outstanding Ratios	(i) Effective Cost Rate (Tables 2 and 3)	(j) Weighted Debt Cost at t = N (h) * (i)
Long Term Debt Cost at Year Ended:	**12/31/2014**										
First Mortgage Bonds:											
(1) 7.09%, Debenture Description, Series, Name of Issuer		1/1/2014	8/31/2030	$ 300,000,000	$ 294,600,000	$ 295,000,000	12	$ 295,156,250	66.23%	7.324%	4.8506%
(2) Coupon rate, Debenture Description, Series, Name of Issuer		1/1/2014	6/30/2025								
Other Long Term Debt:											
(3) 6.6%, Medium Term Notes, Series, Name of Issuer		04/01/2014	06/30/2024	$ 200,000,000	$ 198,000,000	$ 150,000,000	9	$ 150,200,000	33.70%	6.735%	2.2697%
(4) $1,000,000 variable rate LT Credit Line Drawdown, 6.59% (2014 Interest Rate), Series, Name of Issuer		xx/xx/xxx	xx/xx/xxx	na	na	$ 359,000	12	$ 320,000	0.07%	6.590%	0.0047%
Total				$ 500,000,000		$ 445,359,000		$ 445,676,250	100.000%		7.13% **

t = time

The current portion of long term debt is included in the Net Amount Outstanding at t = N in these calculations.

The outstanding amount (column (e)) for debt retired during the year is the outstanding amount at the last month it was outstanding.

* z = Average of monthly balances for months outstanding during the year (averge of the balances for the 12 months of the year, with zero in months that the issuance is not outstanding in a month.).

Interim (individual debenture) debt cost calculations shall be taken to four decimals in percentages (7.2300%, 5.2582%); Final Total Weighted Average Debt Cost for the Formula Rate shall be rounded to two decimals of a percent (7.03%).

** This Total Weighted Average Debt Cost will be shown on Line 101 of formula rate Appendix A.

TABLE 2: Effective Cost Rates For Traditional Front-Loaded Debt Issuances:

YEAR ENDED	12/31/2014

Long Term Debt Issuances	Affiliate	(aa) Issue Date	(bb) Maturity Date	(cc) Amount Issued	(dd) (Discount) Premium at Issuance	(ee) Issuance Expense	(ff) Loss/Gain on Reacquired Debt	(gg) Less Related ADIT (Attachment 1)	(hh) Net Proceeds	(ii) Net Proceeds Ratio	(jj) Coupon Rate	(kk) Annual Interest
First Mortgage Bonds												
(1) 7.09%, Debenture Description, Series, Name of Issuer	No	1/1/2014	6/30/2025	$ 300,000,000	$ (2,400,000)	$ 3,000,000	-	xxx	$ 294,600,000	98.2000	0.07090	$ 21,270,000
(2) Coupon rate, Debenture Description, Series, Name of Issuer		xxx	xxx	xxx	xxx	xxx	xxx	xxx	xxx	xxxx	xxx	xxxx
Other Long Term Debt:												-
(3) 6.6%, Medium Term Notes, Series, Name of Issuer	No	4/1/2014	06/30/2024	200,000,000		2,000,000		xxx	$ 198,000,000	99.0000	0.06600	13,200,000
TOTALS				$ 500,000,000	(2,400,000)	$ 5,000,000	-	xxx	$ 492,600,000			$ 34,470,000

* YTM at issuance calculated from an acceptable bond table or from YTM = Internal Rate of Return (IRR) calculation

Effective Cost Rate of Individual Debenture (YTM at issuance): the t=0 Cashflow C_0 equals Net Proceeds column (gg); Semi-annual (or other) interest cashflows ($C_{t=1}$, $C_{t=2}$, etc.).

(II) Effective Cost Rate* (Yield to Maturity at Issuance, t = 0)
7.324%
xx.xxxx
6.735%

Trans-Allegheny Interstate Line Company
Attachment 8, page 2, Table 3

TABLE 3: Project Financing Costs for Long Term Debt Credit Line Drawdowns using the Internal Rate of Return Methodology

Hypothetical Example: Construction project financing will be a 7 year loan, where by Company pays Origination Fees of $5.2 million; Commitments Fee of 0.3% on the undrawn principal and interest on amounts drawn.

Consistent with GAAP, Company will amortize the Origination Fees and Commitments Fees using the standard Internal Rate of Return ("IRR") formula below.

The IRR is the fluctuating effective yield to maturity of the construction project financing loan at a given time "t".

Each year, Company will reconcile the amounts withdrawn, the interest paid in the year, Origination Fees, Commitments Fees, and total loan amount on this attachment. Company anticipates entering into permanent financing at the end of the term of the project financing, when the project is in-service. At such time, Company will reconcile amounts borrowed, issuance cost, issuance discount or premium, interest paid, etc., on Table 2.

IRR= Internal Rate of Return; NPV = Net Present Value; C = Net Cashflows (Column I below); t = time period; pwr = exponential power.

Total Loan Amount	**$ 550,000,000**

Internal Rate of Return[1] **7.900%**

Based on following Financial Formula[2]**:**

$$\text{NPV} = 0 = \sum_{t=1}^{N} C_t/(1+IRR)pwr(t)$$

Origination Fees	
Underwriting Discount	3,750,000
Issuance & Miscellaneous Expenses	1,450,000
Total Issuance Expense	5,200,000
Revolving Credit Commitments Fee	0.300%

	2007	2008	2009	2010	2011	2012	2013
Interest Rate	6.45%	6.55%	6.65%	6.75%	6.75%	6.75%	6.75%

(A) Year	(B)	(C) Capital Expenditures ($000's)	(D) Principal Drawn In Quarter ($000's)	(E) Principal Drawn To Date ($000's)	(F) Stated Interest Expense ($000's)	(G) Origination Fees ($000's)	(H) Commitments Fee ($000's)	(I) Net Cash Flows ($000's) (D-F-G-H)
2007	Q1	16,809		-	-			
6/1/2007	Q2	21,013	29,781	29,781	160	5,200	130	24,291
7/1/2007	Q3	28,136	14,068	43,849	707		380	12,981
10/1/2007	Q4	32,301	16,151	60,000	967		368	14,816
1/1/2008	Q1	66,438	33,219	93,219	1,526		343	31,349
4/1/2008	Q2	62,484	31,242	124,461	2,038		319	28,885
7/1/2008	Q3	62,709	31,355	155,815	2,551		296	28,507
10/1/2008	Q4	64,355	32,178	187,993	3,078		272	28,828
1/1/2009	Q1	58,262	29,131	217,124	3,610		250	25,272
4/1/2009	Q2	85,821	42,911	260,034	4,323		217	38,370
7/1/2009	Q3	123,768	61,884	321,918	5,352		171	56,361
10/1/2009	Q4	114,084	57,042	378,960	6,300		128	50,614
1/1/2010	Q1	36,594	18,297	397,257	6,704		115	11,479
4/1/2010	Q2	43,691	21,846	419,103	7,072		98	14,675
7/1/2010	Q3	43,694	21,847	440,950	7,441		82	14,324
10/1/2010	Q4	41,316	20,658	461,608	7,790		66	12,802
1/1/2011	Q1	5,614	2,807	464,415	7,837		64	(5,094)
4/1/2011	Q2	5,240	2,620	467,035	7,881		62	(5,323)
7/1/2011	Q3	4,651	2,326	469,360	7,920		60	(5,655)
10/1/2011	Q4	4,618	2,309	471,669	7,959		59	(5,709)
1/1/2012	Q1	-	-	471,669	7,959		59	(8,018)
4/1/2012	Q2	-	-	471,669	7,959		59	(8,018)
7/1/2012	Q3	-	-	471,669	7,959		59	(8,018)
10/1/2012	Q4	-	-	471,669	7,959		59	(8,018)
1/1/2013	Q1	-	-	471,669	7,959		59	(8,018)
4/1/2013	Q2	-	-	471,669	7,959		59	(8,018)
7/1/2013	Q3	-	-	471,669	7,959		59	(8,018)
10/1/2013	Q4	-	-	471,669	479,628		59	(479,687)

[1] The IRR is the Debt Cost shown on Long Term Debt Cost Tables 1 and 2 of Attachment 8. (note in Excel, the Analysis Tool Pack Add-in must be loaded for the cacluation). 7.9% will be used until the construction project debt financing is executed.

[2] The IRR is a discount rate that makes the net present value ("NPV") of a series of cash flows equal to zero. The IRR equation can only be solved through iterations performed by a computer program (i.e. XIRR function in a spreadsheet program).

ATTACHMENT 2

Annual Transmission Revenue Requirements

For 2008 Rate Year

ATTACHMENT H-18A

Trans-Allegheny Interstate Line Company

Line	Formula Rate -- Appendix A	Notes	FERC Form 1 Page # or Instruction	TrAILCo
	Shaded cells are input cells			**2008 Forecast**
	Allocators			
	Wages & Salary Allocation Factor			
1	Transmission Wages Expense		p354.21.b	521,110
2	Total Wages Expense		p354.28.b	1,298,871
3	Less A&G Wages Expense		p354.27.b	777,761
4	Total Wages Less A&G Wages Expense		(Line 2 - Line 3)	521,110
5	**Wages & Salary Allocator**		(Line 1 / Line 4), if line 2 = 0, then 100%	**100.0000%**
	Plant Allocation Factors			
6	Electric Plant in Service	(Note B)	Attachment 5	59,282,298
7	Total Plant In Service		(Line 6)	59,282,298
8	Accumulated Depreciation (Total Electric Plant)		Attachment 5	102
9	Total Accumulated Depreciation		(Line 8)	102
10	Net Plant		(Line 7 - Line 9)	59,282,196
11	Transmission Gross Plant		(Line 15 + Line 21)	59,282,298
12	**Gross Plant Allocator**		(Line 11 / Line 7, if Line 7=0, enter 100%)	**100.0000%**
13	Transmission Net Plant		(Line 11 - Line 29)	59,282,196
14	**Net Plant Allocator**		(Line 13 / Line 10, if line 10=0, enter 100%)	**100.0000%**
	Plant Calculations			
	Transmission Plant			
15	Transmission Plant In Service	(Note B)	Attachment 5	59,282,298
16	New Trans. Plant Adds. for Current Calendar Year (13 average balance)	(Note B)	Attachment 6	7,732,165
17	**Total Transmission Plant**		(Line 15 + Line 16)	**67,014,462**
18	General & Intangible		Attachment 5	0
19	Total General & Intangible		(Line 18)	0
20	Wage & Salary Allocator		(Line 5)	100.0000%
21	**Transmission Related General and Intangible Plant**		(Line 19 * Line 20)	**0**
22	**Transmission Related Plant**		**(Line 17 + Line 21)**	**67,014,462**
	Accumulated Depreciation			
23	Transmission Accumulated Depreciation	(Note B)	Attachment 5	102
24	Accumulated General Depreciation		Attachment 5	0
25	Accumulated Intangible Amortization		Attachment 5	0
26	Total Accumulated General and Intangible Depreciation		(Sum Lines 24 to 25)	0
27	Wage & Salary Allocator		(Line 5)	100.0000%
28	**Transmission Related General & Intangible Accumulated Depreciation**		(Line 26 * Line 27)	**0**
29	**Total Transmission Related Accumulated Depreciation**		**(Line 23 + Line 28)**	**102**
30	**Total Transmission Related Net Property, Plant & Equipment**		**(Line 22 - Line 29)**	**67,014,361**

Adjustment To Rate Base

	Accumulated Deferred Income Taxes				
31	ADIT net of FASB 106 and 109	Enter Negative		Attachment 1	820,517
32	**Transmission Related Accumulated Deferred Income Taxes**			(Line 31)	**820,517**
33	**Transmission Related CWIP (Current Year 13 Month weighted average balances)**		(Note B)	p216.b.43 as shown on Attachment 6	**94,483,653**
34	**Transmission Related Land Held for Future Use**		(Note C)	Attachment 5	**0**
	Transmission Related Pre-Commercial Costs Capitalized				
35	Unamortized Capitalized Pre-Commercial Costs			Attachment 5	**1,419,215**
	Prepayments				
36	**Transmission Related Prepayments**		(Note A)	Attachment 5	**17,682**
	Materials and Supplies				
37	Undistributed Stores Expense		(Note A)	Attachment 5	0
38	Wage & Salary Allocator			(Line 5)	100.0000%
39	Total Undistributed Stores Expense Allocated to Transmission			(Line 37 * Line 38)	0
40	Transmission Materials & Supplies			Attachment 5	0
41	**Transmission Related Materials & Supplies**			(Line 39 + Line 40)	**0**
	Cash Working Capital				
42	Operation & Maintenance Expense			(Line 74)	5,537,387
43	1/8th Rule			1/8	12.5%
44	**Transmission Related Cash Working Capital**			(Line 42 * Line 43)	**692,173**
45	**Total Adjustment to Rate Base**			(Lines 32 + 33 + 34 + 35+ 36 + 41 + 44)	**97,433,240**
46	**Rate Base**			(Line 30 + Line 45)	**164,447,601**

O&M

	Transmission O&M			
47	Transmission O&M		p321.112.b	3,502,178
48	Less Account 566 Misc Trans Exp listed on line 73 below.)		(line 73)	1,301,854
49	Less Account 565		p321.96.b	0
50	Plus Schedule 12 Charges billed to Transmission Owner and booked to Account 565	(Note M)	PJM Data	0
51	Plus Property Under Capital Leases		p200.4.c	0
52	**Transmission O&M**		(Lines 47 - 48 - 49 + 50 + 51)	**2,200,324**
	A&G Expenses			
53	Total A&G		p323.197.b	2,061,274
54	Less Property Insurance Account 924		p323.185.b	0
55	Less Regulatory Commission Exp Account 928	(Note E)	p323.189.b	0
56	Less General Advertising Exp Account 930.1		p323.191.b	0
57	Less PBOP Adjustment		Attachment 5	26,065
58	Less EPRI Dues	(Note D)	p352 & 353	0
59	**A&G Expenses**		(Line 53) - Sum (Lines 54 to 58)	2,035,209
60	Wage & Salary Allocator		(Line 5)	100.0000%
61	**Transmission Related A&G Expenses**		(Line 59 * Line 60)	**2,035,209**
	Directly Assigned A&G			
62	Regulatory Commission Exp Account 928	(Note G)	Attachment 5	0
63	General Advertising Exp Account 930.1	(Note J)	Attachment 5	0
64	Subtotal - Accounts 928 and 930.1 - Transmission Related		(Line 62 + Line 63)	**0**
65	Property Insurance Account 924		p323.185.b	0
66	General Advertising Exp Account 930.1	(Note F)	Attachment 5	0
67	Total Accounts 928 and 930.1 - General		(Line 65 + Line 66)	0
68	Net Plant Allocator		(Line 14)	100.0000%
69	**A&G Directly Assigned to Transmission**		(Line 67 * Line 68)	**0**
	Account 566 Miscellaneous Transmission Expense			
70	Amortization Expense on Pre-Commercial Cost	Account 566	Attachment 5	567,686
71	Pre-Commercial Expense	Account 566	Attachment 5	734,168
72	Miscellaneous Transmission Expense	Account 566	Attachment 5	0
73	Total Account 566		Sum (Lines 70 to 72)	**1,301,854**
74	**Total Transmission O&M**		**(Lines 52 + 61 + 64 + 69 + 73)**	**5,537,387**

	Depreciation & Amortization Expense				
	Depreciation Expense				
75	Transmission Depreciation Expense			Attachment 5	102
76	General Depreciation			p336.10.b&c	0
77	Intangible Amortization		(Note A)	p336.1.d&e	0
78	Total			(Line 76 + Line 77)	0
79	Wage & Salary Allocator			(Line 5)	100.0000%
80	**Transmission Related General Depreciation and Intangible Amortization**			(Line 78 * Line 79)	**0**
81	**Total Transmission Depreciation & Amortization**			**(Lines 75 + 80)**	**102**
	Taxes Other than Income				
82	**Transmission Related Taxes Other than Income**			Attachment 2	**171,335**
83	**Total Taxes Other than Income**			**(Line 82)**	**171,335**
	Return / Capitalization Calculations				
84	**Preferred Dividends**		enter positive	p118.29.c	0
	Common Stock				
85	Proprietary Capital			p112.16.c	78,829,523
86	Less Accumulated Other Comprehensive Income Account 219			p112.15.c	0
87	Less Preferred Stock			(Line 95)	0
88	Less Account 216.1			p112.12.c	0
89	**Common Stock**			(Line 85 - 86 - 87 - 88)	78,829,523
	Capitalization				
90	Long Term Debt		(Note N)		0
91	Less Unamortized Loss on Reacquired Debt			p111.81.c	0
92	Plus Unamortized Gain on Reacquired Debt			p113.61.c	0
93	Less ADIT associated with Gain or Loss			Attachment 1	0
94	Total Long Term Debt			(Line 90 - 91 + 92 - 93)	0
95	Preferred Stock			p112.3.c	0
96	Common Stock			(Line 89)	78,829,523
97	**Total Capitalization**			(Sum Lines 94 to 96)	78,829,523
98	Debt %	Total Long Term Debt	(Note N)	(Line 94 /Line 97)	50.0%
99	Preferred %	Preferred Stock	(Note N)	(Line 95 /Line 97)	0.0%
100	Common %	Common Stock	(Note N)	(Line 96 /Line 97)	50.0%
101	Debt Cost	Total Long Term Debt			0.079
102	Preferred Cost	Preferred Stock		(Line 84 / Line 95)	0.0000
103	Common Cost	Common Stock	(Note I)	The most recent FERC approved ROE	0.1170
104	Weighted Cost of Debt	Total Long Term Debt (WCLTD)		(Line 98 * Line 101)	0.03950
105	Weighted Cost of Preferred	Preferred Stock		(Line 99 * Line 102)	0.0000
106	Weighted Cost of Common	Common Stock		(Line 100 * Line 103)	0.0585
107	**Rate of Return on Rate Base (ROR)**			(Sum Lines 104 to 106)	**0.09800**
108	**Investment Return = Rate Base * Rate of Return**			**(Line 46 * Line 107)**	**16,115,865**

Composite Income Taxes

Line	Description		Reference	Amount
	Income Tax Rates			
109	FIT=Federal Income Tax Rate	(Note H)		35.00%
110	SIT=State Income Tax Rate or Composite			9.30%
111	p	(percent of federal income tax deductible for state purpc	Per State Tax Code	0.00%
112	T	T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =		41.05%
113	T/ (1-T)			69.62%
114	**Income Tax Component =**	CIT=(T/1-T) * Investment Return * (1-(WCLTD/R)) =	[Line 113 * Line 108 * (1- (Line 104 / Line 107))]	**6,697,659**
115	**Total Income Taxes**		**(Line 114)**	**6,697,659**

REVENUE REQUIREMENT

Line	Description		Reference	Amount
	Summary			
116	Net Property, Plant & Equipment		(Line 30)	67,014,361
117	Total Adjustment to Rate Base		(Line 45)	97,433,240
118	**Rate Base**		(Line 46)	**164,447,601**
119	Total Transmission O&M		(Line 74)	5,537,387
120	Total Transmission Depreciation & Amortization		(Line 81)	102
121	Taxes Other than Income		(Line 83)	171,335
122	Investment Return		(Line 108)	16,115,865
123	Income Taxes		(Line 115)	6,697,659
124	**Gross Revenue Requirement**		**(Sum Lines 119 to 123)**	**28,522,347**
	Adjustment to Remove Revenue Requirements Associated with Excluded Transmission Facilities			
125	Transmission Plant In Service		(Line 22)	67,014,462
126	Excluded Transmission Facilities	(Note L)	Attachment 5	0
127	Included Transmission Facilities		(Line 125 - Line 126)	67,014,462
128	Inclusion Ratio		(Line 127 / Line 125)	100.00%
129	Gross Revenue Requirement		(Line 124)	28,522,347
130	**Adjusted Gross Revenue Requirement**		(Line 128 * Line 129)	**28,522,347**
	Revenue Credits			
131	**Revenue Credits**		Attachment 3	0
132	**Net Revenue Requirement**		**(Line 130 - Line 131)**	**28,522,347**
	Net Plant Carrying Charge			
133	Gross Revenue Requirement		(Line 129)	**28,522,347**
134	Net Transmission Plant + CWIP		(Line 17 - Line 23 + Line 33)	**161,498,014**
135	FCR		(Line 133 / Line 134)	**17.6611%**
136	FCR without Depreciation		(Line 133 - Line 75) / Line 134	**17.6611%**
137	FCR without Depreciation and Pre-Commercial Costs		(Line 133 - Line 70 - Line 71 - Line 75) / Line 134	**16.8549%**
138	FCR without Depreciation, Return, nor Income Taxes		(Line 133 - Line 75 - Line 108 - Line 115) / Line 134	**3.5349%**
	Net Plant Carrying Charge Calculation with Incentive ROE			
139	Gross Revenue Requirement Less Return and Taxes		(Line 129 - Line 122 - Line 123)	**5,708,824**
140	Increased Return and Taxes		Attachment 4	**24,208,211**
141	Net Revenue Requirement with Incentive ROE		(Line 139 + Line 140)	**29,917,035**
142	Net Transmission Plant + CWIP		(Line 17 - Line 23+ Line 33)	**161,498,014**
143	FCR with Incentive ROE		(Line 141 / Line 142)	**18.5247%**
144	FCR with Incentive ROE without Depreciation		(Line 141 - Line 75) / Line 142	**18.5246%**
145	FCR with Incentive ROE without Depreciation and Pre-Commercial		(Line 141 - Line 70 - Line 71 - Line 75) / Line 142	**17.7185%**
146	**Net Revenue Requirement**		(Line 132)	**28,522,347**
147	Reconciliation amount		Attachment 6	**1,519,334**
148	Plus any increased ROE calculated on Attach 7 other than PJM Sch. 12 projects not paid by other PJM trans zones		Attachment 7	**1,221,292**
149	Facility Credits under Section 30.9 of the PJM OATT		Attachment 5	**0**
150	**Net Zonal Revenue Requirement**		(Line 146 + 147 + 148 + 149)	**31,262,973**
	Network Zonal Service Rate			
151	1 CP Peak	(Note K)	PJM Data	**N/A**
152	Rate ($/MW-Year)		(Line 150 / 151)	**N/A**
153	**Network Service Rate ($/MW/Year)**		**(Line 152)**	**N/A**

Notes

A Electric portion only

B For both the estimate and the reconciliation, Construction Work In Progress ("CWIP") and leases that are expensed as O&M (rather than amortized) are excluded.
For the Estimate Process:
Transmission plant in service will show the end of year balance and is linked to Attachment 5 which shows detail support by project.
The transmission plant will agree to or be reconciled to the FERC Form 1 balance for the transmission plant.
New Transmission Plant expected to be placed in service in the current calendar year will be based on the average of 13 monthly investment costs and shown separately detailed by project on Attachment 6.
Accumulated depreciation will show the end of year balance and is linked to Attachment 5 which shows detail support by project.
CWIP will be linked to Attachment 6 which shows detail support by project (incentive and non-incentive).
For the Reconciliation Process:
Transmission plant in service will be calculated using a 13 month average balance and will be detailed on Attachment 5. This includes new transmission plant added to plant-in-service
Accumulated depreciation will be calculated using a 13 month average balance and will be detailed on Attachment 5. This includes accumulated depreciation associated with current year transmission plant.
CWIP will be linked to Attachment 6 which shows detail support by project (incentive and non-incentive).

C Includes Transmission portion only and (i) only land that has an estimated in-service date within 10 years may be included and (ii) a plan for the land's use is required to be included in the filing whenever the cost of the land is proposed to be included in rates.

D Excludes all EPRI Annual Membership Dues

E Excludes all Regulatory Commission Expenses

F Includes Safety related advertising included in Account 930.1

G Includes Regulatory Commission Expenses directly related to transmission service, RTO filings, or transmission siting itemized in Form 1 at 351.h.

H 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 includes taxes in more than one state, it must explain in Attachment 5 the name of each state and how the blended or composite SIT was developed.

I ROE will be established in the Commission order accepting the settlement in Docket No. ER07-562 and no change in ROE will be made absent a Section 205 or Section 206 filing at FERC.

J Education and outreach expenses relating to transmission, for example siting or billing

K As provided for in Section 34.1 of the PJM OATT; the PJM established billing determinants will not be revised or updated in the annual rate reconciliations.

L Amount of transmission plant excluded from rates per Attachment 5.

M Payments made under Schedule 12 of the PJM OATT that are not directly assessed to load in the Zone under Schedule 12 are included in Transmission O&M on Line 47. If they are booked to Acct 565, they are included on Line 50. Copies of PJM invoices will be provided upon request.

N The capital structure will remain 50% equity and 50% debt until construction of all of the segments of the TrAIL Project is completed and the entire TrAIL Project is placed in service. The first year that these projects are in service the formula will be run based on the 50/50 capital structure and on the actual year end capital structure. The two results will be weighted based on: the number of days the last project was in service and 365 day minus the numbers of days the last project was in service divided by 365 days.
This can be illustrated using the following example:

Example:

Assume Last Project goes into service on day 260.
Hypothetical Capital Structure until the last project goes into service is 50/50.
Assume Year End actual capital structure is 60% equity and 40% debt.

Therefore: Weighted Equity = [50%*260+60%*(365-260)]/365

Trans-Allegheny Interstate Line Company

Attachment 1 - Accumulated Deferred Income Taxes (ADIT) Worksheet

	Trans-Allegheny Interstate Company								
	B1	**B2**	**B3**	**C**	**D**	**E**	**F**	**G**	
	Beg of Year Total	***End of Year Total***	**End of Year for Est. Average for Final *Total***	**Retail Related**	**Only Transmission Related**	**Plant Related**	**Labor Related**	**Total ADIT**	
ADIT- 282 From Account Total Below	13,935	366,313	366,313	[redacted]	366,313	-	-	366,313	
ADIT-283 From Account Total Below	-	778,287	778,287	[redacted]	778,287	-	-	778,287	
ADIT-190 From Account Total Below	-	(1,965,117)	(1,965,117)	[redacted]	(1,965,117)	-	-	(1,965,117)	Enter Negative
Subtotal					(820,517)	-	-	(820,517)	
Wages & Salary Allocator							100.0000%		
Gross Plant Allocator						100.0000%			
ADIT					(820,517)	-	-	(820,517)	

Note: ADIT associated with Gain or Loss on Reacquired Debt is included in Column A here and included in Cost of Debt on Appendix A, Line 93.

Amount 0 < From Acct 283, below

In filling out this attachment, a full and complete description of each item and justification for the allocation to Columns C-F and each separate ADIT item will be listed, Dissimilar items with amounts exceeding $100,000 will be listed separately.

A	B1	B2	B3	C	D	E	F	G	
	Trans-Allegheny Interstate Company								
ADIT-190	Beg of Year Balance p234.18.b	End of Year Balance p234.18.c	End of Year for Est. Average for Final Total	Retail Related	Gas, Prod Or Other Related	Only Transmission Related	Plant Related	Labor Related	JUSTIFICATION
Tax Interest Capitalized	-	1,042,269	1,042,269			1,042,269	-		Actual amount of tax interest capitalized
Depreciation	-	42	42			42			Depreciation as shown on the tax return
Intercompany Charges	-	102,289	102,289			102,289			Intercompany charges from the AP service company
Worker's Compensation	-	42,230	42,230			42,230			Actual amount of reserve for workers' compensation
Deferred Tax Reclassification	-	778,287	778,287			778,287			Accumulated deferred income taxes reclassified from account 283
	-	-	-						
Subtotal	-	1,965,117	1,965,117	-	-	1,965,117	-	-	
Less FASB 109 included above									
Less FASB 106 included above									
Total	-	1,965,117	1,965,117	-	-	1,965,117	-	-	

Instructions for Account 190:

1. ADIT items related only to Retail Related Operations are directly assigned to Column C.
2. ADIT items related only to Non-Electric Operations (e.g., Gas, Water, Sewer) or Production are directly assigned to Column D.
3. ADIT items related only to Transmission are directly assigned to Column E.
4. ADIT items related to Plant and not in Columns C, D & E are directly assigned to Column F.
5. ADIT items related to labor and not in Columns C, D, E & F are directly assigned to Column G.
6. Deferred income taxes arise when items are included in taxable income in different periods than they are included in rates. Therefore, if the item giving rise to the ADIT is not included in the formula, the associated ADIT amount shall be excluded.

PJM TRANSMISSION OWNER

Attachment 1 - Accumulated Deferred Income Taxes (ADIT) Worksheet

A	B1	B2	B3	C	D	E	F	G	
	Trans-Allegheny Interstate Company								
ADIT- 282	**Beg of Year Balance p274.9.b**	**End of Year Balance p275.9.k**	**End of Year for Est. Average for Final Total**	**Retail Related**	**Gas, Prod Or Other Related Related**	**Only Transmission Related Related**	**Plant Related Related**	**Labor Related Related**	**JUSTIFICATION**
Property Related	13,935	366,313	366,313			366,313			Allowance for borrowed funds used during construction (ABFUDC)
	-	-	-						
	-	-	-						
	-	-	-						
	-	-	-						
	-	-	-						
	-	-	-						
	-	-	-						
	-	-	-						
Subtotal	13,935	366,313	366,313	-	-	366,313	-	-	
Less FASB 109 included above				-	-	-	-	-	
Less FASB 106 included above	-	-	-	-	-	-	-	-	
Total	13,935	366,313	366,313		-	366,313	-	-	

Instructions for Account 282:

1. ADIT items related only to Retail Related Operations are directly assigned to Column C.
2. ADIT items related only to Non-Electric Operations (e.g., Gas, Water, Sewer) or Production are directly assigned to Column D.
3. ADIT items related only to Transmission are directly assigned to Column E.
4. ADIT items related to Plant and not in Columns C, D & E are directly assigned to Column F.
5. ADIT items related to labor and not in Columns C, D, E & F are directly assigned to Column G.
6. Deferred income taxes arise when items are included in taxable income in different periods than they are included in rates. Therefore, if the item giving rise to the ADIT is not included in the formula, the associated ADIT amount shall be excluded.

PJM TRANSMISSION OWNER

Attachment 1 - Accumulated Deferred Income Taxes (ADIT) Worksheet

A	B1	B2	B3	C	D	E	F	G	
	Trans-Allegheny Interstate Company								
ADIT-283	Beg of Year Balance p276.19.b	End of Year Balance p277.19.k	End of Year for Est. Average for Final Total	Retail Related	Gas, Prod Or Other Related	Only Transmission Related	Plant Related	Labor Related	JUSTIFICATION
	-	-	-						
	-	778,287	778,287			778,287			ADIT Balance Sheet Reclassification
	-	-	-						
	-	-	-						
Subtotal	-	778,287	778,287		-	778,287	-	-	
Less FASB 109 included above									
Less FASB 106 included above									
Total	-	778,287	778,287		-	778,287	-	-	

Instructions for Account 283:

1. ADIT items related only to Retail Related Operations are directly assigned to Column C.
2. ADIT items related only to Non-Electric Operations (e.g., Gas, Water, Sewer) or Production are directly assigned to Column D.
3. ADIT items related only to Transmission are directly assigned to Column E.
4. ADIT items related to Plant and not in Columns C, D & E are directly assigned to Column F.
5. ADIT items related to labor and not in Columns C, D, E & F are directly assigned to Column G.

6. Deferred income taxes arise when items are included in taxable income in different periods than they are included in rates. Therefore, if the item giving rise to the ADIT is not included in the formula, the associated ADIT amount shall be excluded.

Trans-Allegheny Interstate Line Company

Attachment 2 - Taxes Other Than Income Worksheet

	Other Taxes	FERC Form No.1 page, line & Col	Amount	Allocator	Allocated Amount	
	Plant Related			**Gross Plant Allocator**		
1	Real property (State, Municipal or Local)			100.0000%	$ -	
2	Capital Stock Tax	p263.25(i)	3,004	100.0000%	3,004	
3	Gross Premium (Insurance) Tax			100.0000%	-	
4	Public Utility Realty Tax Act (PURTA), 72 P.S. §8101, *et seq.*			100.0000%	-	
5	Corp License	p263.35(i)	288	100.0000%	288	
6	Other State License			100.0000%	-	
7					-	
8	**Total Plant Related**		3,292	100.0000%	3,292	
	Labor Related			**Wages & Salary Allocator**		
9	Federal FICA Capitalized					
10	Federal Unemployment	p263.4(i)	2,079			
11	State Unemployment	p263.39(i)	7,774			
12	Accrued FICA	p263.3(i)	143,649			
13						
14	**Total Labor Related**		153,502	100.0000%	153,502	
	Other Included			**Gross Plant Allocator**		
15	Miscellaneous					
16	Use and Sales Tax	p263.23(i)	14,541			
17						
18						
19	**Total Other Included**		14,541	100.0000%	14,541	
20	**Total Included (Lines 8 + 14 + 19)**		171,335		**171,335**	Input to Appendix A, Line 82
	Retail Related Other Taxes to be Excluded					
21	Federal Income Tax	p263.2(i)	1,849,498			
22	Corporate Net Income Tax	p263.33(i)	546,076			
23			0			
24			0			
25			0			
26			0			
27			0			
28			0			
29			0			
30			0			
31	**Subtotal, Excluded**		2,395,574			
32	**Total, Included and Excluded (Line 20 + Line 28)**		2,566,909			
33	**Total Other Taxes from p114.14.c**		171,335			
34	Difference (Line 32 - Line 33)		2,395,574			

Criteria for Allocation:

A Other taxes that are incurred through ownership of plant including transmission plant will be allocated based on the Gross Plant Allocator. If the taxes are 100% recovered at retail they shall not be included.

B Other taxes that are incurred through ownership of only general or intangible plant will be allocated based on the Wages and Salary Allocator. If the taxes are 100% recovered at retail they shall not be included.

C Other taxes that are assessed based on labor will be allocated based on the Wages and Salary Allocator.

D Other taxes except as provided for in A, B and C above, that are incurred and (1) are not fully recovered at retail or (2) are directly or indirectly related to transmission service will be allocated based on the Gross Plant Allocator; provided, however, that overheads shall be treated as in footnote B above.

E Excludes prior period adjustments in the first year of the formula's operation and reconciliation for the first year.

Trans-Allegheny Interstate Line Company

Attachment 3 - Revenue Credit Workpaper

			Amount	FERC Form No.1 page, line & Col
	Account 454 - Rent from Electric Property			
1	Rent from Electric Property - Transmission Related (Note 3)		-	
2	Total Rent Revenues	(Line 1)	-	
	Account 456 - Other Electric Revenues (Note 1)			
3	Schedule 1A		-	
4	Net revenues associated with Network Integration Transmission Service (NITS) for which the load is not included in the divisor (difference between NITS credits from PJM and PJM NITS charges paid by Transmission Owner) (Note 4)		-	
5	Point to Point Service revenues for which the load is not included in the divisor received by Transmission Owner		-	
6	PJM Transitional Revenue Neutrality (Note 1)			
7	PJM Transitional Market Expansion (Note 1)			
8	Professional Services (Note 3)		-	
9	Revenues from Directly Assigned Transmission Facility Charges (Note 2)		-	
10	Rent or Attachment Fees associated with Transmission Facilities (Note 3)		-	
11	Gross Revenue Credits	(Sum Lines 2-10)	-	
12	Less line 14g		-	
13	Total Revenue Credits	(Line 11 - Line 12)	-	Input to Appendix A, Line 131
	Revenue Adjustment to determine Revenue Credit			
14a	Revenues associated with lines 14b-g are to be included in lines 2-10 and total of those revenues entered here		-	
14b	Costs associated with revenues in line 14a		-	
14c	Net Revenues (14a - 14b)		-	
14d	50% Share of Net Revenues (14c / 2)		-	
14e	Costs associated with revenues in line 14a that are included in FERC accounts recovered through the formula times the allocator used to functionalize the amounts in the FERC account to the transmission service at issue.		-	
14f	Net Revenue Credit (14d + 14e)		-	
14g	Line 14a less line 14f		-	
15	Amount offset in line 4 above		-	
16	Total Account 454 and 456			

17 Note 1: All revenues related to transmission that are received as a transmission owner (i.e., not received as a LSE), for which the cost of the service is recovered under this formula, except as specifically provided for elsewhere in this Attachment or elsewhere in the formula will be included as a revenue credit or included in the peak on line 178 of Appendix A.

18 Note 2: If the costs associated with the Directly Assigned Transmission Facility Charges are included in the Rates, the associated revenues are included in the Rates. If the costs associated with the Directly Assigned Transmission Facility Charges are not included in the Rates, the associated revenues are not included in the Rates.

19 Note 3: Ratemaking treatment for the following specified secondary uses of transmission assets: (1) right-of-way leases and leases for space on transmission facilities for telecommunications; (2) transmission tower licenses for wireless antennas; (3) right-of-way property leases for farming, grazing or nurseries; (4) licenses of intellectual property (including a portable oil degasification process and scheduling software); and (5) transmission maintenance and consulting services (including energized circuit maintenance, high-voltage substation maintenance, safety training, transformer oil testing, and circuit breaker testing) to other utilities and large customers (collectively, products). Company will retain 50% of net revenues consistent with Pacific Gas and Electric Company, 90 FERC ¶ 61,314. Note: in order to use lines 14a - 14g, the utility must track in separate subaccounts the revenues and costs associated with each secondary use (except for the cost of the associated income taxes).

20 Note 4: If the facilities associated with the revenues are not included in the formula, the revenue is shown here, but not included in the total above and explained in the Cost Support. For example revenues associated with distribution facilities. In addition Revenues from Schedule 12 of the PJM OATT are not included in the total above to the extent they are credited under Schedule 12 of the PJM OATT.

Trans-Allegheny Interstate Line Company

Attachment 4 - Calculation with Incentive ROE

	Return and Taxes at High End of the range of Reasonableness				
A	Return and Taxes at High End of the range of Reasonableness	(Sum Lines 26 and 33 from below)		24,208,211	Input to Appendix A, Line 140
B	Difference between Base ROE and Incentive ROE			100	

Return Calculation

			Source Reference		
1	Rate Base		Appendix A, Line 46		164,447,601
2	Preferred Dividends	enter positive	Appendix A, Line 84		0
	Common Stock				
3	Proprietary Capital		Appendix A, Line 85		78,829,523
4	Less Accumulated Other Comprehensive Income Account 219		Appendix A, Line 86		0
5	Less Preferred Stock		Appendix A, Line 87		0
6	Less Account 216.1		Appendix A, Line 88		0
7	Common Stock		Appendix A, Line 89		78,829,523
	Capitalization				
8	Long Term Debt		Appendix A, Line 90		0
9	Less Unamortized Loss on Reacquired Debt		Appendix A, Line 91		0
10	Plus Unamortized Gain on Reacquired Debt		Appendix A, Line 92		0
11	Less ADIT associated with Gain or Loss		Appendix A, Line 93		0
12	Total Long Term Debt		Appendix A, Line 94		0
13	Preferred Stock		Appendix A, Line 95		0
14	Common Stock		Appendix A, Line 96		78,829,523
15	Total Capitalization		Appendix A, Line 97		78,829,523
16	Debt %	Total Long Term Debt	Appendix A, Line 98		50%
17	Preferred %	Preferred Stock	Appendix A, Line 99		0%
18	Common %	Common Stock	Appendix A, Line 100		50%
19	Debt Cost	Total Long Term Debt	Appendix A, Line 101		0.0790
20	Preferred Cost	Preferred Stock	Appendix A, Line 102		0.0000
21	Common Cost	Common Stock		12.70%	0.1270
22	Weighted Cost of Debt	Total Long Term Debt (WCLTD)	(Line 16 * 19)		0.0395
23	Weighted Cost of Preferred	Preferred Stock	(Line 17 * 20)		0.0000
24	Weighted Cost of Common	Common Stock	(Line 18 * 21)		0.0635
25	Rate of Return on Rate Base (ROR)		(Sum Lines 22 to 24)		**0.1030**
26	Investment Return = Rate Base * Rate of Return		**(Line 1 * Line 25)**		**16,938,103**

Composite Income Taxes

	Income Tax Rates			
27	FIT=Federal Income Tax Rate		Appendix A, Line 109	35.00%
28	SIT=State Income Tax Rate or Composite		Appendix A, Line 110	9.30%
29	p = percent of federal income tax deductible for state purposes		Appendix A, Line 111	0.00%
30	T	T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =	Appendix A, Line 112	41.05%
31	T/ (1-T)		Appendix A, Line 113	69.62%
32	**Income Tax Component =**	CIT=(T/1-T) * Investment Return * (1-(WCLTD/R)) =		7,270,108
33	**Total Income Taxes**		**(Line 32)**	**7,270,108**

Trans-Allegheny Interstate Line Company

Attachment 5 - Cost Support

Plant in Service Worksheet

Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions

Line	Calculation of Transmission Plant In Service	Source		13 Month Balance For reconciliation Total	EOY Balance for Estimate Total	Details: 13 Month Plant Balance For reconciliation — Black Oak	Wylie Ridge	502 Junction - Territorial Line	500 kV Prexy - 502 Junction	138 kV Prexy - 502 Junction	Meadowbrook Transformer	North Shenadoah	Total
	December	p206.58.b	For 2006	-		-	-	-	-	-	-	-	-
	January	company records	For 2007	-		-	-	-	-	-	-	-	-
	February	company records	For 2007	-		-	-	-	-	-	-	-	-
	March	company records	For 2007	-		-	-	-	-	-	-	-	-
	April	company records	For 2007	79,718		79,718	-	-	-	-	-	-	79,718
	May	company records	For 2007	79,718		79,718	-	-	-	-	-	-	79,718
	June	company records	For 2007	82,135		82,135	-	-	-	-	-	-	82,135
	July	company records	For 2007	82,135		82,135	-	-	-	-	-	-	82,135
	August	company records	For 2007	79,815		79,815	-	-	-	-	-	-	79,815
	September	company records	For 2007	79,815		79,815	-	-	-	-	-	-	79,815
	October	company records	For 2007	457,882		82,153	-	375,730	-	-	-	-	457,882
	November	company records	For 2007	460,874		82,153	-	378,721	-	-	-	-	460,874
	December	p207.58.g (and notes)	For 2007	59,282,298	59,282,298	44,367,279	12,763,316	2,151,702	-	-	-	-	59,282,298
15	**Transmission Plant In Service**			**4,668,030**	**59,282,298**	**3,462,686**	**981,794**	**223,550**	**-**	**-**	**-**	**-**	**4,668,030**
				Link to Appendix A, line 15	**Link to Appendix A, line 15**								

Line	Calculation of Distribution Plant In Service	Source		13 Month Balance For reconciliation Total	EOY Balance for Estimate Total
	December	p206.75.b	For 2006	-	
	January	company records	For 2007	-	
	February	company records	For 2007	-	
	March\	company records	For 2007	-	
	April	company records	For 2007	-	
	May	company records	For 2007	-	
	June	company records	For 2007	-	
	July	company records	For 2007	-	
	August	company records	For 2007	-	
	September	company records	For 2007	-	
	October	company records	For 2007	-	
	November	company records	For 2007	-	
	December	p207.75.g	For 2007	-	-
	Distribution Plant In Service			-	-

Line	Calculation of Intangible Plant In Service	Source		13 Month Balance For reconciliation Total	EOY Balance for Estimate Total
	December	p204.5.b	For 2006	-	
	December	p205.5.g	For 2007	-	-
18	**Intangible Plant In Service**			-	-
				Link to Appendix A, line 18	**Link to Appendix A, line 18**

Line	Calculation of General Plant In Service	Source		13 Month Balance For reconciliation Total	EOY Balance for Estimate Total
	December	p206.99.b	For 2006	-	
	December	p207.99.g	For 2007	-	-
18	**General Plant In Service**			-	-
				Link to Appendix A, line 18	**Link to Appendix A, line 18**

Line	Calculation of Production Plant In Service	Source		13 Month Balance For reconciliation Total	EOY Balance for Estimate Total
	December	p204.46b	For 2006	-	
	January	company records	For 2007	-	
	February	company records	For 2007	-	
	March\	company records	For 2007	-	
	April	company records	For 2007	-	
	May	company records	For 2007	-	
	June	company records	For 2007	-	
	July	company records	For 2007	-	
	August	company records	For 2007	-	
	September	company records	For 2007	-	
	October	company records	For 2007	-	
	November	company records	For 2007	-	
	December	p205.46.g	For 2007	-	-
	Production Plant In Service			-	-

Line		Source		13 Month Balance For reconciliation Total	EOY Balance for Estimate Total
6	**Total Plant In Service**	Sum of averages above		4,668,029.96	59,282,297.57
				Link to Appendix A, line 6	**Link to Appendix A, line 6**

Trans-Allegheny Interstate Line Company

Attachment 5 - Cost Support

Accumulated Depreciation Workshee

Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions

Details

Line	Calculation of Transmission Accumulated Depreciation	Source		13 Month Balance For reconciliation	EOY Balance for Estimate	13 Month Balance For reconciliation: Black Oak	Wylie Ridge	502 Junction - Territorial Line	500 kV Prexy - 502 Junction	138 kV Prexy - 502 Junction	Meadowbrook Transformer	North Shenadoah	Total
	December	Prior year FERC Form 1 p219.25.b	For 2006	-		-	-	-	-	-	-	-	-
	January	company records	For 2007	-		-	-	-	-	-	-	-	-
	February	company records	For 2007	-		-	-	-	-	-	-	-	-
	March\	company records	For 2007	-		-	-	-	-	-	-	-	-
	April	company records	For 2007	-		-	-	-	-	-	-	-	-
	May	company records	For 2007	-		-	-	-	-	-	-	-	-
	June	company records	For 2007	-		-	-	-	-	-	-	-	-
	July	company records	For 2007	-		-	-	-	-	-	-	-	-
	August	company records	For 2007	-		-	-	-	-	-	-	-	-
	September	company records	For 2007	-		-	-	-	-	-	-	-	-
	October	company records	For 2007	-		-	-	-	-	-	-	-	-
	November	company records	For 2007	51		-	-	51	-	-	-	-	51
	December	p219.25.b	For 2007	102	102	-	-	102	-	-	-	-	102
23	**Transmission Accumulated Depreciatior**			**12**	**102**	**-**	**-**	**12**	**-**	**-**	**-**	**-**	**12**
				Link to Appendix A, line 23	**Link to Appendix A, line 23**								

Line	Calculation of Distribution Accumulated Depreciation	Source		13 Month Balance For reconciliation	EOY Balance for Estimate
	December	Prior year FERC Form 1 p219.26.b	For 2006	-	
	January	company records	For 2007	-	
	February	company records	For 2007	-	
	March\	company records	For 2007	-	
	April	company records	For 2007	-	
	May	company records	For 2007	-	
	June	company records	For 2007	-	
	July	company records	For 2007	-	
	August	company records	For 2007	-	
	September	company records	For 2007	-	
	October	company records	For 2007	-	
	November	company records	For 2007	-	
	December	p219.26.b	For 2007	-	-
	Distribution Accumulated Depreciatior			-	-

Line	Calculation of Intangible Accumulated Depreciation	Source		13 Month Balance For reconciliation	EOY Balance for Estimate
	December	Prior year FERC Form 1 p200.21.b	For 2006		
	December	p200.21b	For 2007	-	-
25	**Accumulated Intangible Depreciatior**			-	-
				Link to Appendix A, line 25	**Link to Appendix A, line 25**

Line	Calculation of General Accumulated Depreciation	Source		13 Month Balance For reconciliation	EOY Balance for Estimate
	December	Prior year FERC Form 1 p219.28b	For 2006		
	December	p219.28.b	For 2007	-	-
24	**Accumulated General Depreciatior**			-	-
				Link to Appendix A, line 24	**Link to Appendix A, line 24**

Line	Calculation of Production Accumulated Depreciation	Source		13 Month Balance For reconciliation	EOY Balance for Estimate
	December	Prior year FERC Form 1 p219.20.b	For 2006	-	
	January	company records	For 2007	-	
	February	company records	For 2007	-	
	March\	company records	For 2007	-	
	April	company records	For 2007	-	
	May	company records	For 2007	-	
	June	company records	For 2007	-	
	July	company records	For 2007	-	
	August	company records	For 2007	-	
	September	company records	For 2007	-	
	October	company records	For 2007	-	
	November	company records	For 2007	-	
	December	p219.20.b thru 219.24.b	For 2007	-	-
	Production Accumulated Depreciation			-	-
8	**Total Accumulated Depreciation**	Sum of averages above		**11.74**	**101.78**
				Link to Appendix A, line 8	**Link to Appendix A, line 8**

Trans-Allegheny Interstate Line Company

Attachment 5 - Cost Support

Electric / Non-electric Cost Support

	Link to Appendix A, line #s, Descriptions, Notes, Form 1 Page #s and Instructions			Form 1 Amount	Electric Portion	Non-electric Portion	Details
				Beg of year	End of Year (for estimate)	Average of Beginning and Ending Balances	
	Materials and Supplies						
40	Transmission Materials & Supplies		p227.8	-	-	-	
37	Undistributed Stores Expense		p227.16	-	-	-	
	Allocated General Expenses						
51	Plus Property Under Capital Leases	0	p200.4.c	-	-	-	

Transmission / Non-transmission Cost Support

	Link to Appendix A, line #s, Descriptions, Notes, Form 1 Page #s and Instructions		Beg of year	End of Year (for estimate)	Average of Beginning and Ending Balances	Details
34	Transmission Related Land Held for Future Use	Total	-	-	-	Enter Details Here
		Non-transmission Related	-	-	-	
		Transmission Related	-	-	-	

CWIP & Expensed Lease Worksheet

	Link to Appendix A, line #s, Descriptions, Notes, Form 1 Page #s and Instructions			Beg of year	CWIP In Form 1 Amount	Expensed Lease in Form 1 Amount	Details
	Plant Allocation Factors						
6	Electric Plant in Service	(Note B)	Attachment 5	-	-	-	
	Plant In Service						
15	Transmission Plant In Service	(Note B)	Attachment 5	-	-	-	
	Accumulated Depreciation						
23	Transmission Accumulated Depreciation	(Note B)	Attachment 5	-	-	-	

Trans-Allegheny Interstate Line Company

Attachment 5 - Cost Support

Pre-Commercial Costs Capitalized

	Link to Appendix A, line #s, Descriptions, Notes, Form 1 Page #s and Instructions	EOY for Estimate and BOY for Final	Amortization Amount (Over 4 Years)	Calculated End of Year Balance	Average of Beginning and Ending Balances (for estimate and reconciliation)
35	Unamortized Capitalized Pre-Commercial Costs	$ 1,703,058	$ 567,686	$ 1,135,372	$ 1,419,215

EPRI Dues Cost Support

	Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions			Beg of year	EPRI Dues	Details
	Allocated General & Common Expenses					
58	Less EPRI Dues	(Note D)	p352 & 353			Enter Details Here

Regulatory Expense Related to Transmission Cost Support

	Link to Appendix A, line #s, Descriptions, Notes, Form 1 Page #s and Instructions			Form 1 Amount	Transmission Related	Non-transmission Related		Details
	Directly Assigned A&G							
62	Regulatory Commission Exp Account 928	(Note G)	p323.189.b	-	-	-	Link to Appendix A, line 66	Enter Details Here

Safety Related Advertising Cost Support

	Link to Appendix A, line #s, Descriptions, Notes, Form 1 Page #s and Instructions			Form 1 Amount	Safety Related	Non-safety Related		Details
	Directly Assigned A&G							
66	General Advertising Exp Account 930.1	(Note F)	p323.191.b	-	-	-	Link to Appendix A, line 70	Enter Details Here

MultiState Workpaper

	Link to Appendix A, line #s, Descriptions, Notes, Form 1 Page #s and Instructions		State 1	State 2	State 3	State 4	State 5	Details
	Income Tax Rates							
			Composite					
110	SIT=State Income Tax Rate or Composite	(Note I)	9.30%					

Education and Out Reach Cost Support

	Link to Appendix A, line #s, Descriptions, Notes, Form 1 Page #s and Instructions			Form 1 Amount	Education & Outreach	Other	Details
	Directly Assigned A&G						
63	General Advertising Exp Account 930.1	(Note J)	p323.191.b	-	-	-	Enter Details Here

Trans-Allegheny Interstate Line Company

Attachment 5 - Cost Support

Excluded Plant Cost Support

	Link to Appendix A, line #s, Descriptions, Notes, Form 1 Page #s and Instructions			Excluded Transmission Facilities	Description of the Facilities
	Adjustment to Remove Revenue Requirements Associated with Excluded Transmission Facilities				
126	Excluded Transmission Facilities		(Note L)		General Description of the Facilities
	Step-Up Facilities			-	
	Instructions:			Enter $	
1	Remove all investment below 69 kV or generator step up transformers included in transmission plant in service that are not a result of the RTEP Process				
2	If unable to determine the investment below 69kV in a substation with investment of 69 kV and higher as well as below 69 kV,			Or	
	the following formula will be used:	Example		Enter $	
A	Total investment in substation	1,000,000			
B	Identifiable investment in Transmission (provide workpapers)	500,000			
C	Identifiable investment in Distribution (provide workpapers)	400,000			
D	Amount to be excluded (A x (C / (B + C)))	444,444			
					Add more lines if necessary

Prepayments

	Link to Appendix A, line #s, Descriptions, Notes, Form 1 Page #s and Instructions		Beg of year	End of Year	Average of Beginning and Ending Balances	Allocation	Transmission Related	Details
36	Prepayments				Enter $		Amount	
	Prepayments	Prepaid Insurance	-	35,363	17,682	100%	17,682	
	Prepaid Pensions if not included in Prepayments		-	0	0	100%	0	
	Total Prepayments		-	35,363	17,682		17,682	

Trans-Allegheny Interstate Line Company

Attachment 5 - Cost Support

Detail of Account 566 Miscellaneous Transmission Expenses

	Link to Appendix A, line #s, Descriptions, Notes, Form 1 Page #s and Instructions		Total
70	Amortization Expense on Pre-Commercial Cost		$ 567,686
71	Pre-Commercial Expense		734,168
72	Miscellaneous Transmission Expense		-
	Total Account 566 Miscellaneous Transmission Expenses	p.321	$ 1,301,854
	Net Revenue Requirement		
149	Facility Credits under Section 30.9 of the PJM OATT		-

Details

Summary of Pre-Commercial Expenses

Cost Element Name	Total
Labor & Overhead (1)	398,966
Miscellaneous (2)	6,727
Outside Services Legal (3)	(38,212)
Outside Services Other (4)	232,415
Outside Services Rates (5)	48,400
Advertising (6)	53,605
Travel, Lodging and Meals (7)	32,267
Total	734,168

(1) Labor & overhead amount includes costs allocated to preparation of the preliminary survey and investigation.
(2) Miscellaneous amount includes rental of volunteer fire department facilities for open houses, Fed EX fees for various mailings from Legal, Procurement, Transmission & Finance, fees for various conference calls and PJM application fee.
(3) Outside legal services includes the cost for research and preparation of the filing to determine incentive rate availability.
(4) Other services other includes fees for website development, media relations services, campaign management, open houses and research services.
(5) Outside services rates includes the advice of a rate consultant regarding rate design.
(6) Advertising includes newspaper and other media announcements of public scoping meetings related to the proposed project.
(7) Travel, lodging and meals are the direct expenses for Allegheny staff to attend the scoping meetings.

Depreciation Rates

TRANSMISSION PLANT		Life		Survivor Curve	Net Salvage Percent	Accrual Rate (Annual) Percent	Annual Depreciation Expense: Black Oak	Wylie Ridge		502 Junction - Territorial Line	500 kV Prexy - 502 Junction	138 kV Prexy - 502 Junction	Project X	Total
350.2	Land & Land Rights - Easements	70	-	R4	0	1.43	-	-	-	-	-	-		-
352	Structures & Improvements	50	-	R3	(10)	2.20	-	-	-	-	-	-		-
	SVC	35	-			2.86	-	-	-	-	-	-		-
									-					
353	Station Equipment								-					
	Other	50	-	R2	(5)	2.10	-		-	102	-	-		102
	SVC	Note 1	-	80 R2 - 35-yr truncation		2.96	-	-	-	-	-	-		-
	SCADA	15	-	S3	0	6.67	-	-	-	-	-	-		-
354	Towers & Fixtures	65	-	R4	(25)	1.92	-	-	-	-	-	-		-
355	Poles & Fixtures	55	-	R2.5	(20)	2.18	-	-	-	-	-	-		-
356	Overhead Conductors & Devices													
	Other	50	-	R2.5	(40)	2.80	-	-	-	-	-	-		-
	Clearing	70	-	R4	0	1.43	-	-	-	-	-	-		-
357	Underground conduit	55	-	S3	(5)	1.91	-	-	-	-	-	-		-
358	Underground conductor and devices	45	-	R3	(5)	2.33	-	-	-	-	-	-		-
	SVC	35				2.86	-	-	-	-	-	-		-
Total Depreciation Expense (must tie to p336.7.	102						-	-	-	102	-	-	-	102

Note 1: Depreciation rate is based on an 80 R2 survivor curve with a 35-year truncation.
These depreciation rates will not change absent the appropriate filing at FEF

PBOP Expenses

	1	Total PBOP expenses	22,856,433
	2	Amount relating to retired personnel	8,786,372
	3	Amount allocated on FTEs	14,070,061
	4	Number of FTEs for Allegheny	4,408
	5	Cost per FTE	3,192
	6	TrAILCo FTEs (labor not capitalized) current year	5.06
	7	TrAILCo PBOP Expense for base year	16,145
	8	TrAILCo PBOP Expense in Account 926 for current year	42,210
57	9	PBOP Adjustment for Appendix A, Line 57	(26,065)

Lines 1-5 cannot change absent approval or acceptance by FERC in a separate proceeding.

Trans-Allegheny Interstate Line Company

Attachment 5a - Pre-Commercial Costs and CWIP

Step 1 Totals reported below are by project with the amounts to be expensed reported separately from those to be deferred and amortized (note, deferred costs related to 2006 include AFUDC).

For Forecasting purposes, Pre-Commercial expenses will be estimated. Total deferred and amortized Pre-commercial costs will be the actual amount agreeing to FERC Form 1 and Attachment 5.

Step 2 For each project, where CWIP is to be recovered in rate base, CWIP will be estimated and the totals reported below by project. For the Reconciliation, for each project where CWIP is to be recovered in rate base the CWIP will be itemized by project below. Additionally, the amount of AFUDC that would have been capitalized for projects where CWIP is included in rate base will be reported in the FERC Form No. 1.

Step 3 For the Reconciliation, the total additions to plant in service for that year will be summarized by project to demonstrate no Pre-Commercial costs expensed were included in the additions to plant in service and AFUDC on projects where CWIP was recovered in rate base was included in the additions to plant in service. The Pre-commercial expenses are actual expenses incurred for the reconciliation year. Total deferred and amortized Pre-commercial costs will be the actual amount agreeing to FERC Form 1 and Attachment 5.

	Column A	Column B	Column C	Column D		Column E	Column F	Column G
			Pre-Commercial Costs			CWIP		
Step 1	**For Estimate:**	Expensed (Estimated)	Deferred	Amount of Deferred Amortized in Year	**Estimate Step 2**	Average of 13 Monthly Balances		
	Prexy - 502 Junction 138 kV (CWIP)	78,808		60,937		13,464,419		
	Prexy - 502 Junction 500 kV (CWIP)	101,511		78,492		12,949,275		
	502 Junction - Territorial Line (CWIP)	553,849		428,257		68,069,959		
	Total	734,168	1,703,058	567,686		94,483,653		
Step 3	**For Reconciliation:**		Pre-Commercial Costs		**For Reconciliation Step 2**	CWIP	AFUDC In CWIP	AFUDC (If CWIP was not in Rate Base)
	Prexy - 502 Junction 138 kV (CWIP)	Expensed (Actual)	Deferred	Amount of Deferred Amortized in Year				
	1	78,808	182,812	60,937				
	2	-		-				
	3	-		-				
	4	-		-				
	…							
	Total	78,808	182,812	60,937				
	Prexy - 502 Junction 500 kV (CWIP)							
	1	101,511	235,476	78,492				
	2	-		-				
	3	-		-				
	4	-		-				
	…							
	Total	101,511	235,476	78,492				
	502 Junction - Territorial Line (CWIP)							
	1	553,849	1,284,770	428,257				
	2	-		-				
	3	-		-				
	4	-		-				
	…							
	Total	553,849	1,284,770	428,257				

Total Additions to Plant In Service (sum of the above for each project)
Total Additions to Plant in Service reported on pages 200-204 of the Form No. 1
Difference (must be zero)

Notes:

1 Small projects may be combined into larger projects where rate treatment is consistent. Pre-Commercial costs benefiting multiple projects will be allocated to projects based on the estimated plant in service of each project.

Allocation of Pre-Commercial Costs	Plant in Service (Estimated 2/12/2008)	Allocation
Prexy - 502 Junction 138 kV (CWIP)	94,140,000	0.10734
Prexy - 502 Junction 500 Kv (CWIP)	121,260,000	0.13827
502 Junction - Territorial Line (CWIP)	661,600,000	0.75439
Total	877,000,000	1.00000

2 Column D is the total CWIP balance including any AFUDC, Column E is the AFUDC if any in Column D, and Column F is the AFUDC that would have been in Column E if CWIP were not recovered in rate base.

Trans-Allegheny Interstate Line Company

Attachment 6 - Estimate and Reconciliation Worksheet

Step	Month	Year	Action
Exec Summary			
1	April	Year 2	TO populates the formula with Year 1 data
2	April	Year 2	TO estimates all transmission Cap Adds and CWIP for Year 2 based on each project's cost using the average of 13 monthly balances. Cap Adds are the projects expected to be in service in Year 2.
3	April	Year 2	TO adds Cap Adds and CWIP to plant in service in Formula (Appendix A, Lines 16 and 33)
4	May	Year 2	Post results of Step 3 on PJM web site
5	June	Year 2	Results of Step 3 go into effect
6	April	Year 3	TO estimates all transmission Cap Adds and CWIP during Year 3 based each project's cost using the average of 13 monthly balances. Cap Adds are expected be in service in Year 3.
7	April	Year 3	Reconciliation - TO calculates Reconciliation by populating the 13 monthly plant balances and beginning and end of year balances for the other rate base items and the 13 monthly averages for CWIP in Reconciliation (adjusted to include any Reconciliation amount from prior year).
8	April	Year 3	Reconciliation - TO adds the difference between the Reconciliation in Step 7 and the forecast in Step 5 with interest to the result of Step 7 (this difference is also added to Step 7 in the subsequent year)
9	May	Year 3	Post results of Step 8 on PJM web site
10	June	Year 3	Results of Step 8 go into effect

Reconciliation Details

1 April Year 2 TO populates the formula with Year 1 data

Rev Req based on Year 1 data

Must run Appendix A to get this number (without any cap adds in Appendix A line 16 and without CWIP in Appendix A line 33)

2 April Year 2 TO estimates all transmission Cap Adds and CWIP for Year 2 based on each project's cost using the average of 13 monthly balances. Cap Adds are the projects expected to be in service in Year 2.

	(A) Other Projects PIS (monthly additions)	(B) Black Oak (monthly additions) (in service)	(C) Wylie Ridge (monthly additions) (in service)	(D) 502 Junction - Territorial Line (monthly additions) CWIP	(E) 500 kV Prexy - 502 Junction (monthly additions) CWIP	(F) 138 kV Prexy - 502 Junction (monthly additions) CWIP	Month End Balances: Other Projects PIS (monthly additions)	Black Oak (monthly balance) (in service)	Wylie Ridge (monthly balance) (in service)	502 Junction - Territorial Line (monthly balance) CWIP	500 kV Prexy - 502 Junction (monthly balance) CWIP	138 kV Prexy - 502 Junction (monthly balance) CWIP
Dec (Prior Year CWIP) p216.b.43				29,078	3,120	2,421				29,078	3,120	2,421
Jan 2007		-	-	100,000	168,900	131,100		-	-	129,078	172,020	133,521
Feb		-	-	100,000	168,900	131,100		-	-	229,078	340,920	264,621
Mar		-	-	1,900,000	225,200	174,800		-	-	2,129,078	566,120	439,421
Apr		-	-	2,200,000	619,300	480,700		-	-	4,329,078	1,185,420	920,121
May		-	-	2,200,000	619,300	480,700		-	-	6,529,078	1,804,720	1,400,821
Jun		-	-	2,200,000	619,300	480,700		-	-	8,729,078	2,424,020	1,881,521
Jul		-	-	2,200,000	675,600	524,400		-	-	10,929,078	3,099,620	2,405,921
Aug		-	-	2,100,000	619,300	480,700		-	-	13,029,078	3,718,920	2,886,621
Sep		-	-	2,000,000	675,600	524,400		-	-	15,029,078	4,394,520	3,411,021
Oct		-	7,618,489	4,100,000	788,200	611,800		-	7,618,489	19,129,078	5,182,720	4,022,821
Nov		-	-	3,200,000	788,200	611,800		-	7,618,489	22,329,078	5,970,920	4,634,621
Dec		49,528,583	7,329,602	3,200,000	788,200	611,800		49,528,583	14,948,091	25,529,078	6,759,120	5,246,421
Total	-	49,528,583	14,948,091	25,529,078	6,759,120	5,246,421		49,528,583	30,185,069	128,078,014	35,622,155	27,649,878
New Transmission Plant Additions for Year 2 (13 month average balance)							Average 13 Month Balance	3,809,891	2,321,928	9,852,155	2,740,166	2,126,914
								(Appendix A, Line 16)	(Appendix A, Line 16)	(Appendix A, Line 33)	(Appendix A, Line 33)	(Appendix A, Line 33)

3 April Year 2 TO adds Cap Adds and CWIP to plant in service in Formula (Appendix A, Lines 16 and 33)

4 May Year 2 Post results of Step 3 on PJM web site

Total Revenue Requirement	Black Oak (monthly additions)	Wylie Ridge (monthly additions)	502 Junction - Territorial Line (monthly additions)	500 kV Prexy - 502 Junction (monthly additions)	138 kV Prexy - 502 Junction (monthly additions)
$ 7,010,015	444,422	401,037	4,330,967	1,032,310	801,279

5 June Year 2 Results of Step 3 go into effect

6 April Year 3 TO estimates all transmission Cap Adds and CWIP during Year 3 based each project's cost using the average of 13 monthly balances. Cap Adds are expected be in service in Year 3.

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
		Meadowbrook Transformer (monthly additions)	North Shenandoah (monthly additions)	Black Oak (monthly additions)	Wylie Ridge (monthly additions)	502 Junction - Territorial Line (monthly additions)	500 kV Prexy - 502 Junction (monthly additions)	138 kV Prexy - 502 Junction (monthly additions)
		(in service)	(in service)	(in service)	(in service)	CWIP	CWIP	CWIP
Dec (Prior Year CWIP) p216.b.43	Actual				197,754	20,651,884	5,244,579	4,808,804
Jan 2008	Actual			(22,702)	263,171	4,293,957	840,954	206,229
Feb	Actual			124,272	103,624	2,558,667	106,363	646,181
Mar	Actual			144,349	15,171	3,694,409	691,038	561,300
Apr	Actual			53,780	32,114	3,027,346	452,945	583,461
May	Budget	8,376,439	2,309,887	60,000	1,000	3,723,096	1,107,046	652,025
Jun	Budget	200,000	-	-	1,000	4,845,848	1,131,268	1,640,887
Jul	Budget	100,000	-	-	1,000	8,657,237	3,138,696	2,190,571
Aug	Budget	40,000	-	-	-	19,123,669	2,203,356	2,767,924
Sep	Budget	15,000	-	-	-	26,501,863	2,280,989	5,702,856
Oct	Budget	5,000	-	640,000	-	21,369,973	2,131,446	2,058,061
Nov	Budget	-	-	-	-	36,472,126	5,216,999	6,641,396
Dec	Budget	-	-	-	-	18,242,867	5,336,228	6,122,254
Total		8,736,439	2,309,887	999,699	614,834	173,162,941	29,881,907	34,581,949

New Transmission Plant Additions for Year 2 (13 month average balance)

Month End Balances

Other Projects PIS (Monthly additions)	Meadowbrook Transformer (monthly additions)	North Shenandoah (monthly additions)	Black Oak (monthly balance) (in service)	Wylie Ridge (monthly balance) (in service)	502 Junction - Territorial Line (monthly balance) CWIP	500 kV Prexy - 502 Junction (monthly balance) CWIP	138 kV Prexy - 502 Junction (monthly balance) CWIP
[redacted]	-	-	-	197,754	20,651,884	5,244,579	4,808,804
	-	-	(22,702)	460,926	24,945,841	6,085,533	5,015,033
	-	-	101,570	564,549	27,504,508	6,191,896	5,661,214
	-	-	245,919	579,720	31,198,916	6,882,934	6,222,515
	-	-	299,699	611,834	34,226,262	7,335,879	6,805,975
	8,376,439	2,309,887	359,699	612,834	37,949,358	8,442,925	7,458,000
	8,576,439	2,309,887	359,699	613,834	42,795,206	9,574,193	9,098,887
	8,676,439	2,309,887	359,699	614,834	51,452,443	12,712,889	11,289,458
	8,716,439	2,309,887	359,699	614,834	70,576,112	14,916,245	14,057,382
	8,731,439	2,309,887	359,699	614,834	97,077,975	17,197,234	19,760,238
	8,736,439	2,309,887	999,699	614,834	118,447,948	19,328,680	21,818,299
	8,736,439	2,309,887	999,699	614,834	154,920,074	24,545,679	28,459,695
	8,736,439	2,309,887	999,699	614,834	173,162,941	29,881,907	34,581,949
	69,286,514	18,479,097	5,422,080	7,330,452	884,909,470	168,340,573	175,037,451
	5,329,732	1,421,469	417,083	563,881	68,069,959	12,949,275	13,464,419

Total Revenue Requirement	Meadowbrook Transformer (monthly additions)	North Shenadoah (monthly additions)	Black Oak (monthly additions)	Wylie Ridge (monthly additions)	502 Junction - Territorial Line (monthly additions)	500 kV Prexy - 502 Junction (monthly additions)	138 kV Prexy - 502 Junction (monthly additions)
$ 29,743,638.96	898,323	239,588	7,935,132	2,246,291	13,424,438	2,474,425	2,525,443

7 April Year 3 Reconciliation - TO calculates Reconciliation by populating the 13 monthly plant balances and beginning and end of year balances for the other rate base items and the 13 monthly averages for CWIP in Reconciliation (adjusted to include any Reconciliation amount from prior year).

	(A)	(B)	(C)	(D)		Month End Balances				
	502 Junction - Territorial Line (monthly additions)	500 kV Prexy - 502 Junction (monthly additions)	138 kV Prexy - 502 Junction (monthly additions)	Wylie Ridge (monthly additions)		502 Junction - Territorial Line (monthly balance)	500 kV Prexy - 502 Junction (monthly balance)	138 kV Prexy - 502 Junction (monthly balance)	Wylie Ridge (monthly additions)	Total
	CWIP	CWIP	CWIP	(in service)		CWIP	CWIP	CWIP		
Dec (Prior Year CWIP) p216.b.43	29,078	2,928	2,613			29,078	2,928	2,613	0	
Jan 2007	-	-	-			29,078	2,928	2,613	0	
Feb	4,378	-	-			33,455	2,928	2,613	0	
Mar	151,079	-	60			184,534	2,928	2,673	0	
Apr	2,341,369	564,082	218,794			2,525,903	567,010	221,468	0	
May	1,647,451	101,022	42,273			4,173,354	668,032	263,741	0	
Jun	2,481,436	494,537	234,017			6,654,790	1,162,569	497,759	0	
Jul	1,975,834	435,348	239,276			8,630,624	1,597,917	737,034	0	
Aug	2,387,279	644,797	421,307			11,017,903	2,242,714	1,158,342	0	
Sep	2,529,975	702,818	461,676			13,547,878	2,945,532	1,620,017	0	
Oct	2,087,239	744,465	667,299			15,635,117	3,689,997	2,287,316	0	
Nov	2,458,043	828,367	566,151			18,093,159	4,518,363	2,853,467	0	
Dec	2,558,724	726,216	1,955,336	197,754		20,651,884	5,244,579	4,808,804	197,754	
Total	20,651,884	5,244,579	4,808,804	197,754		101,206,758	22,648,425	14,458,461	197,754	
					Average 13 Month Balance	7,785,135	1,742,187	1,112,189	15,212	10,654,723 Input to Appendix A, line 33

Result of Formula for Reconciliation

Total Revenue Requirement	Black Oak (monthly additions)	Wylie Ridge (monthly additions)	502 Junction - Territorial Line (monthly additions)	500 kV Prexy - 502 Junction (monthly additions)	138 kV Prexy - 502 Junction (monthly additions)	
$ 8,410,662	1,608,748	453,038	4,702,999	989,415	656,463	Must run Appendix A with cap adds in Appendix A, line 16 and CWIP in Appendix line 33

8 April Year 3 Reconciliation - TO adds the difference between the Reconciliation in Step 7 and the forecast in Step 5 with interest to the result of Step 7 (this difference is also added to Step 7 in the subsequent year)

The Reconciliation in Step 8		The forecast in Prior Year			
8,410,662	-	7,010,015	=	1,400,647	<Note: for the first rate year, divide this reconciliation amount by 12 and multiply by the number of months and fractional months the rate was in effect.

Interest on Amount of Refunds or Surcharges
Interest 35.19a for March Current Yr 0.6600%

Month	Yr	1/12 of Step 9	Interest 35.19a for March Current Yr	Months	Interest	Surcharge (Refund) Owed
Jun	Year 1	116,721	0.6600%	11.5	8,859	125,580
Jul	Year 1	116,721	0.6600%	10.5	8,089	124,809
Aug	Year 1	116,721	0.6600%	9.5	7,318	124,039
Sep	Year 1	116,721	0.6600%	8.5	6,548	123,269
Oct	Year 1	116,721	0.6600%	7.5	5,778	122,498
Nov	Year 1	116,721	0.6600%	6.5	5,007	121,728
Dec	Year 1	116,721	0.6600%	5.5	4,237	120,958
Jan	Year 2	116,721	0.6600%	4.5	3,467	120,187
Feb	Year 2	116,721	0.6600%	3.5	2,696	119,417
Mar	Year 2	116,721	0.6600%	2.5	1,926	118,647
Apr	Year 2	116,721	0.6600%	1.5	1,156	117,876
May	Year 2	116,721	0.6600%	0.5	385	117,106
Total		1,400,647				1,456,113

		Balance	Interest	Amort	Balance
Jun	Year 2	1,456,113	0.6600%	126,611	1,339,112
Jul	Year 2	1,339,112	0.6600%	126,611	1,221,339
Aug	Year 2	1,221,339	0.6600%	126,611	1,102,789
Sep	Year 2	1,102,789	0.6600%	126,611	983,456
Oct	Year 2	983,456	0.6600%	126,611	863,336
Nov	Year 2	863,336	0.6600%	126,611	742,423
Dec	Year 2	742,423	0.6600%	126,611	620,712
Jan	Year 3	620,712	0.6600%	126,611	498,197
Feb	Year 3	498,197	0.6600%	126,611	374,874
Mar	Year 3	374,874	0.6600%	126,611	250,737
Apr	Year 3	250,737	0.6600%	126,611	125,781
May	Year 3	125,781	0.6600%	126,611	(0)
Total with interest				1,519,334	

The difference between the Reconciliation in Step 8 and the forecast in Prior Year with interest		1,519,334	Input to Appendix A, Line 147
Rev Req based on Year 2 data with estimated Cap Adds for Year 3 (Step 8)	$	29,743,639	
Revenue Requirement for Year 3		31,262,973	

Reconciliation amount by Project

Total Reconciliation Amount	Black Oak (monthly additions)	Wylie Ridge (monthly additions)	502 Junction - Territorial Line (monthly additions)	500 kV Prexy - 502 Junction (monthly additions)	138 kV Prexy - 502 Junction (monthly additions)
$ 1,519,334	$ 1,262,987	$ 56,407	$ 403,557	$ (46,530)	$ (157,087)

9 May Year 3 Post results of Step 8 on PJM web site

$ 31,262,973 Post results of Step 3 on PJM web site

10 June Year 3 Results of Step 8 go into effect

$ 31,262,973

Trans-Allegheny Interstate Line Company

Attachment 7 - Transmission Enhancement Charge Worksheet

1 **Revenue Requirement By Project**

Line					
2	**Fixed Charge Rate (FCR) if not a CIAC**				
		Formula Line			
3	A	137	FCR without Depreciation and Pre-Commercial Costs		16.8549%
4	B	145	FCR with Incentive ROE without Depreciation and Pre-Commercial		17.7185%
5	C		Line B less Line A		0.8636%
6	**FCR if a CIAC**				
7	D	138	FCR without Depreciation, Return, nor Income Taxes		3.5349%

8 **The FCR resulting from Formula in a given year is used for that year only.**
9 **Therefore actual revenues collected in a year do not change based on cost data for subsequent years**

Line				**PJM Upgrade ID: b0321.2; b0321.3**	**PJM Upgrade ID: b0321.1**
10		Details		Prexy - 502 Junction 138 kV (CWIP + Plant In Service)	Prexy - 502 Junction 500 kV (CWIP+ Plant In Service)
11	"Yes" if a project under PJM OATT Schedule 12, otherwise "No"	Schedule 12	(Yes or No)	Yes	Yes
12	"Yes" if the customer has paid a lump sum payment in the amount of the investment on line 29, Otherwise "No"	CIAC	(Yes or No)	No	No
13	Input the allowed ROE	Allowed ROE		12.70%	12.70%
14	From line 3 above if "No" on line 12 and From line 7 above if "Yes" on line 12	FCR without Incentive ROE		16.8549%	16.8549%
15	If line 13 equals 12.7%, then line 4, if line 13 equals 11.7% then line 3, and if line 12 is "Yes" then line 7	FCR for This Project		17.7185%	17.7185%
16	forecast of CWIP or Cap Adds. reconciliation – Average of 13 month prior year net plant balances plus prior year 13-mo CWIP balances.	Investment		13,464,419	12,949,275
17	Annual Depreciation Exp from Attachment 5			-	-

Line			Invest Yr	Return	Depreciation	Pre-Commercial Exp.	**Reconciliation Amount**	Revenue	Return	Depreciation	Pre-Commercial Exp.	**Reconciliation amount**	Revenue
18													
19	See Calculations for each item below	Wo Incentive ROE	2007	2,269,420	-	139,745	(157,087)	2,252,078	2,182,592	-	180,003	(46,530)	2,316,066
20	See Calculations for each item below	W Incentive ROE	2007	2,385,698	-	139,745	(157,087)	2,368,356	2,294,422	-	180,003	(46,530)	2,427,895

For Plant in Service
"Pre-Commercial Exp" is equal to the amount of pre-commercial expense on Attachment 5a for each project expensed in year and amortized in year.
Revenue is equal to the "Return" ("Investment" times FCR) plus "Depreciation" plus "Pre-Commercial Exp" plus prior year "Reconciliation amount"
"Reconciliation Amount" is created in the reconciliation in Attachment 6 and included in the forecasted revenue requirement.

1
2
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9

Line	Description	PJM Upgrade ID: b0328.2; b0347.1; b0347.2; b0347.3; b0347.4	PJM Upgrade ID: b0218	PJM Upgrade ID: b0216
10		502 Junction - Territorial Line (CWIP + Plant In Service)	Wylie Ridge Transformer (Plant In Service)	Black Oak (SVC) Dynamic Reactive Device (Plant In Service)
11	"Yes" if a project under PJM OATT Schedule 12, otherwise "No"	Yes	Yes	Yes
12	"Yes" if the customer has paid a lump sum payment in the amount of the investment on line 29, Otherwise "No"	No	No	No
13	Input the allowed ROE	12.70%	11.70%	12.70%
14	From line 3 above if "No" on line 12 and From line 7 above if "Yes" on line 12	16.8549%	16.8549%	16.8549%
15	If line 13 equals 12.7%, then line 4, if line 13 equals 11.7% then line 3, and if line 12 is "Yes" then line 7	17.7185%	16.8549%	17.7185%
16	forecast of CWIP or Cap Adds. reconciliation – Average of 13 month prior year net plant balances plus prior year 13-mo CWIP balances.	70,221,560	13,327,197	44,784,362
17	Annual Depreciation Exp from Attachment 5	102	-	-

Line	Description	Return	Depreciation	Pre-Commercial Exp.	**Reconciliation Amount**	Revenue	Return	Depreciation	**Reconciliation Amount**	Revenue	Return	Depreciation	**Reconciliation Amount**	Revenue
18														
19	See Calculations for each item below	11,835,801	102	982,106	403,557	13,221,565	2,246,291	-	56,407	2,302,698	7,548,377	-	1,262,987	8,811,364
20	See Calculations for each item below	12,442,230	102	982,106	403,557	13,827,995	2,246,291	-	56,407	2,302,698	7,935,132	-	1,262,987	9,198,119

For Plant in Service
"Pre-Commercial Exp" is equal to the amount of pre-comme
Revenue is equal to the "Return" ("Investment" times FCR)
"Reconciliation Amount" is created in the reconciliation in At

Line	Description	PJM Upgrade ID: b0323				PJM Upgrade ID: b0230							
1													
2													
3													
4													
5													
6													
7													
8													
9													
10		North Shenandoah Transformer (Plant In Service)				Meadowbrook Transformer (Plant In Service)							
11	"Yes" if a project under PJM OATT Schedule 12, otherwise "No"	Yes				Yes							
12	"Yes" if the customer has paid a lump sum payment in the amount of the investment on line 29, Otherwise "No"	No				No							
13	Input the allowed ROE	0.00%				11.70%							
14	From line 3 above if "No" on line 12 and From line 7 above if "Yes" on line 12	16.8549%				16.8549%							
15	If line 13 equals 12.7%, then line 4, if line 13 equals 11.7% then line 3, and if line 12 is "Yes" then line 7	16.8549%				16.8549%							
16	forecast of CWIP or Cap Adds. reconciliation – Average of 13 month prior year net plant balances plus prior year 13-mo CWIP balances.	1,421,469				5,329,732							
17	Annual Depreciation Exp from Attachment 5												
18		Return	Depreciation	**Reconciliation Amount**	Revenue	Return	Depreciation	**Reconciliation Amount**	Revenue	Total	Incentive Charged	Revenue Credit	$ 1,221,292
19	See Calculations for each item below	239,588			239,588	898,323			898,323	30,041,681		30,041,681	**Ax A Line 148**
20	See Calculations for each item below	239,588			239,588	898,323			898,323	31,262,973	31,262,973		

For Plant in Service
"Pre-Commercial Exp" is equal to the amount of pre-comme
Revenue is equal to the "Return" ("Investment" times FCR)
"Reconciliation Amount" is created in the reconciliation in At

Template for Annual Information Filings with Formula Rate Debt Cost Disclosure and True-Up

Attachment 8, page 1, Table 1 and 2

Template for Annual Information Filings with Formula Rate Debt Cost Disclosure and True-Up

TABLE 1: Summary Cost of Long Term Debt

CALCULATION OF COST OF DEBT/Hypothetical Example

YEAR ENDED	12/31/2014

		t=N	(a) Issue Date	(b) Maturity Date	(c) ORIGINAL ISSUANCE	(d) Net Proceeds At Issuance	(e) Net Amount Outstanding at t=N	(f) Months Outstanding at t=N	(g) Average Net Outstanding in Year* z*	(h) Weighted Outstanding Ratios	(i) Effective Cost Rate (Tables 2 and 3)	(j) Weighted Debt Cost at t = N (h) * (i)	
	Long Term Debt Cost at Year Ended:	12/31/2014											
	First Mortgage Bonds:												
(1)	7.09%, Debenture Description, Series, Name of Issuer		1/1/2014	8/31/2030	$ 300,000,000	$ 294,600,000	$ 295,000,000	12	$ 295,156,250	66.23%	7.324%	4.8506%	
(2)	Coupon rate, Debenture Description, Series, Name of Issuer		1/1/2014	6/30/2025									
	Other Long Term Debt:												
(3)	6.6%, Medium Term Notes, Series, Name of Issuer		04/01/2014	06/30/2024	$ 200,000,000	$ 198,000,000	$ 150,000,000	9	$ 150,200,000	33.70%	6.735%	2.2697%	
(4)	$1,000,000 variable rate LT Credit Line Drawdown, 6.59% (2014 Interest Rate), Series, Name of Issuer		xx/xx/xxx	xx/xx/xxx	na	na	$ 359,000	12	$ 320,000	0.07%	6.590%	0.0047%	
	Total				$ 500,000,000		$ 445,359,000		$ 445,676,250	100.000%		7.13%	**

t = time

The current portion of long term debt is included in the Net Amount Outstanding at t = N in these calculations.

The outstanding amount (column (e)) for debt retired during the year is the outstanding amount at the last month it was outstanding.

* z = Average of monthly balances for months outstanding during the year (averge of the balances for the 12 months of the year, with zero in months that the issuance is not outstanding in a month.).

Interim (individual debenture) debt cost calculations shall be taken to four decimals in percentages (7.2300%, 5.2582%); Final Total Weighted Average Debt Cost for the Formula Rate shall be rounded to two decimals of a percent (7.03%).

** This Total Weighted Average Debt Cost will be shown on Line 101 of formula rate Appendix A.

TABLE 2: Effective Cost Rates For Traditional Front-Loaded Debt Issuances:

YEAR ENDED	12/31/2014

	Long Term Debt Issuances	Affiliate	(aa) Issue Date	(bb) Maturity Date	(cc) Amount Issued	(dd) (Discount) Premium at Issuance	(ee) Issuance Expense	(ff) Loss/Gain on Reacquired Debt	(gg) Less Related ADIT (Attachment 1)	(hh) Net Proceeds	(ii) Net Proceeds Ratio	(jj) Coupon Rate	(kk) Annual Interest	(ll) Effective Cost Rate* (Yield to Maturity at Issuance, t = 0)
	First Mortgage Bonds													
(1)	7.09%, Debenture Description, Series, Name of Issuer	No	1/1/2014	6/30/2025	$ 300,000,000	$ (2,400,000)	$ 3,000,000	-	xxx	$ 294,600,000	98.2000	0.07090	$ 21,270,000	7.324%
(2)	Coupon rate, Debenture Description, Series, Name of Issuer		xxx	xxx	xxx	xxx	xxx	xxx	xxx	xxx	xxxx	xxx	xxxx	xx.xxxx
	Other Long Term Debt:												-	
(3)	6.6%, Medium Term Notes, Series, Name of Issuer	No	4/1/2014	06/30/2024	200,000,000		2,000,000		xxx	$ 198,000,000	99.0000	0.06600	13,200,000	6.735%
	TOTALS				$ 500,000,000	(2,400,000)	$ 5,000,000	-	xxx	$ 492,600,000			$ 34,470,000	

* YTM at issuance calculated from an acceptable bond table or from YTM = Internal Rate of Return (IRR) calculation

Effective Cost Rate of Individual Debenture (YTM at issuance): the t=0 Cashflow C_t equals Net Proceeds column (gg); Semi-annual (or other) interest cashflows ($C_{t=1}$, $C_{t=2}$, etc.).

Trans-Allegheny Interstate Line Company
Attachment 8, page 2, Table 3

TABLE 3: Project Financing Costs for Long Term Debt Credit Line Drawdowns using the Internal Rate of Return Methodology

Hypothetical Example: Construction project financing will be a 7 year loan, where by Company pays Origination Fees of $5.2 million; Commitments Fee of 0.3% on the undrawn principal and interest on amounts drawn.

Consistent with GAAP, Company will amortize the Origination Fees and Commitments Fees using the standard Internal Rate of Return ("IRR") formula below.

The IRR is the fluctuating effective yield to maturity of the construction project financing loan at a given time "t".

Each year, Company will reconcile the amounts withdrawn, the interest paid in the year, Origination Fees, Commitments Fees, and total loan amount on this attachment. Company anticipates entering into permanent financing at the end of the term of the project financing, when the project is in-service. At such time, Company will reconcile amounts borrowed, issuance cost, issuance discount or premium, interest paid, etc., on Table 2.

IRR= Internal Rate of Return; NPV = Net Present Value; C = Net Cashflows (Column I below); t = time period; pwr = exponential power.

Total Loan Amount	**$ 550,000,000**

Internal Rate of Return[1] **7.900%**

Based on following Financial Formula[2]**:**

$$\text{NPV} = 0 = \sum_{t=1}^{N} C_t/(1+IRR)pwr(t)$$

Origination Fees	
Underwriting Discount	3,750,000
Issuance & Miscellaneous Expenses	1,450,000
Total Issuance Expense	5,200,000
Revolving Credit Commitments Fee	0.300%

	2007	2008	2009	2010	2011	2012	2013
Interest Rate	6.45%	6.55%	6.65%	6.75%	6.75%	6.75%	6.75%

(A) Year	(B)	(C) Capital Expenditures ($000's)	(D) Principal Drawn In Quarter ($000's)	(E) Principal Drawn To Date ($000's)	(F) Stated Interest Expense ($000's)	(G) Origination Fees ($000's)	(H) Commitments Fee ($000's)	(I) Net Cash Flows ($000's) (D-F-G-H)
2007	Q1	16,809		-	-			
6/1/2007	Q2	21,013	29,781	29,781	160	5,200	130	24,291
7/1/2007	Q3	28,136	14,068	43,849	707		380	12,981
10/1/2007	Q4	32,301	16,151	60,000	967		368	14,816
1/1/2008	Q1	66,438	33,219	93,219	1,526		343	31,349
4/1/2008	Q2	62,484	31,242	124,461	2,038		319	28,885
7/1/2008	Q3	62,709	31,355	155,815	2,551		296	28,507
10/1/2008	Q4	64,355	32,178	187,993	3,078		272	28,828
1/1/2009	Q1	58,262	29,131	217,124	3,610		250	25,272
4/1/2009	Q2	85,821	42,911	260,034	4,323		217	38,370
7/1/2009	Q3	123,768	61,884	321,918	5,352		171	56,361
10/1/2009	Q4	114,084	57,042	378,960	6,300		128	50,614
1/1/2010	Q1	36,594	18,297	397,257	6,704		115	11,479
4/1/2010	Q2	43,691	21,846	419,103	7,072		98	14,675
7/1/2010	Q3	43,694	21,847	440,950	7,441		82	14,324
10/1/2010	Q4	41,316	20,658	461,608	7,790		66	12,802
1/1/2011	Q1	5,614	2,807	464,415	7,837		64	(5,094)
4/1/2011	Q2	5,240	2,620	467,035	7,881		62	(5,323)
7/1/2011	Q3	4,651	2,326	469,360	7,920		60	(5,655)
10/1/2011	Q4	4,618	2,309	471,669	7,959		59	(5,709)
1/1/2012	Q1	-	-	471,669	7,959		59	(8,018)
4/1/2012	Q2	-	-	471,669	7,959		59	(8,018)
7/1/2012	Q3	-	-	471,669	7,959		59	(8,018)
10/1/2012	Q4	-	-	471,669	7,959		59	(8,018)
1/1/2013	Q1	-	-	471,669	7,959		59	(8,018)
4/1/2013	Q2	-	-	471,669	7,959		59	(8,018)
7/1/2013	Q3	-	-	471,669	7,959		59	(8,018)
10/1/2013	Q4	-	-	471,669	479,628		59	(479,687)

[1] The IRR is the Debt Cost shown on Long Term Debt Cost Tables 1 and 2 of Attachment 8. (note in Excel, the Analysis Tool Pack Add-in must be loaded for the cacluation). 7.9% will be used until the construction project debt financing is executed.

[2] The IRR is a discount rate that makes the net present value ("NPV") of a series of cash flows equal to zero. The IRR equation can only be solved through iterations performed by a computer program (i.e. XIRR function in a spreadsheet program).

ATTACHMENT 3

Accounting of Transfers Between

CWIP and Plant In Service

Trans-Allegheny Interstate Line Company
Detail Transfers from CWIP to Plant in Service

Work Order ID	Work Order Number	FERC Account 106 Sub-Account	Project / Description	Amount	Date of Transfer from CWIP to Plant in Service
			Wylie Ridge Transformer		
10970691	D-01109.1301C	353.104 & 353.204	WYLIE RIDGE : Inst #6 & #8 XF	12,763,316	December 20, 2007
			Black Oak (SVC)		
10970696	D-01314.1301C	350.104 & 353.504	BLACK OAK SS INST SVC STATCOM	44,285,126	December 5, 2007
10970697	D-01314.1502C	350.102	Black Oak SS: Purch Property	79,718	April 9, 2007
10970697	D-01314.1502C	350.102	Black Oak SS: Purch Property	2,417	May 2007
10970697	D-01314.1502C	350.102	Black Oak SS: Purch Property (AFUDC Correction)	(2,320)	August 2007
10970697	D-01314.1502C	350.102	Black Oak SS: Purch Property	2,338	October 2007
			Total	44,367,279	
			502 Junction to Territorial Line		
10970694	D-01458.1301C	353.204	BP5133 TRAIL PID for time MT Storm	29,078	October 31,2007
10970694	D-01458.1301C	353.204	BP5133 TRAIL PID for time MT Storm	247	December 2007
11064767	D-01458.2304C	350.104	502 JCT SS PURCHASE PROPERTY	346,652	October 31,2007
11064767	D-01458.2304C	350.104	502 JCT SS PURCHASE PROPERTY	2,991	November 2007
11064767	D-01458.2304C	350.104	502 JCT SS PURCHASE PROPERTY	1,772,734	December 2007
			Total	2,151,702	