UNITIL ENERGY SYSTEMS, INC.

DIRECT TESTIMONY OF

FRANCIS X. WELLS

New Hampshire Public Utilities Commission

Docket No.: DE 09-

June 17, 2009

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I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Francis X. Wells. My business address is 6 Liberty Lane West, Hampton, NH.

Q. For whom do you work and in what capacity?

A. I am employed by Unitil Service Corp. ("USC") as Senior Energy Trader. USC provides management and administrative services to Unitil Energy Systems, Inc. ("UES") and Unitil Power Corp. ("UPC").

Q. Please summarize your educational background and professional qualifications.

A. I received my Bachelor of Arts Degree in both Economics and History from the University of Maine in 1995. I joined USC in September 1996 as an Analyst, assisting in the planning and operation of both electric power and natural gas supply portfolios. Since January 2001 I have worked as a Senior Energy Trader in the Energy Contracts Department. I have responsibilities in the area of energy supply acquisition, including default service purchasing, regulatory reporting, budgeting, and long-term supply planning.

Q. Have you previously testified before the Commission?

A. Yes. I have testified on numerous occasions before the Commission.

II. SUMMARY OF TESTIMONY

Q. Please summarize your testimony in this proceeding.

A. I will present and explain the cost data and underlying reasons for the proposed changes to UES' Stranded Cost Charge ("SCC"), and External Delivery Charge ("EDC"), effective August 1, 2009. Ms. Linda S. McNamara presents the reconciliation for the SCC and EDC through July 2009 and the rate development for the SCC and EDC for the period beginning August 1, 2009 and ending July 31, 2010, based on the cost data I discuss in my testimony.

III. STRANDED COST CHARGE COSTS

Q. What costs are included in the SCC?

A. The SCC includes the Contract Release Payments ("CRP") from Unitil Power Corp., charged in accordance with the Amended Unitil System Agreement, approved by both the Commission in Docket No. 01-247 and by the FERC.

Schedule FXW-1, page 1, provides a description of the CRP. Page 2 provides the CRP by month reflecting actual data from May 2007 through April 2009 and estimated data from May 2009 through July 2010. Actual data for the months May 2007 through January 2008 was included in UES' last rate and reconciliation filing, Docket No. DE 08-040. Rather than present partial data beginning with February 2008, UES is presenting the full period.

Q. Please describe the Amended Unitil System Agreement.

A. The purpose of this Amended Unitil System Agreement was to restructure UES' power supply in order to implement retail choice. Prior to the implementation of the Amended Unitil System Agreement on May 1, 2003, UES purchased full-requirements power supply from UPC at fully reconciling, cost-of-service rates.

The Amended Unitil System Agreement provides for termination of power sales from UPC to UES and the payment of UPC's on-going costs by UES. These on-going costs are defined in the Amended Unitil System Agreement as either CRP or Administrative Service Charges ("ASC"). UES recovers the CRP through the SCC and the ASC through the EDC. I will discuss the ASC later in my testimony when I discuss the EDC costs.

Q. Please describe the CRP.

A. The CRP is calculated in accordance with Appendix 1 of the Amended Unitil System Agreement. The CRP is equal to the sum of the Portfolio Sales Charge, the Residual Contract Obligations, the Hydro-Quebec Support Payments, and True-Ups from Prior Periods.

The Portfolio Sales Charge is equal to the specified monthly payment stream made by UPC to Mirant Energy Trading, LLC ("MET"), pursuant the Mirant Agreement, which continues through October 2010. The Mirant Agreement provides for the transfer of most of UPC's purchase power obligations to MET in exchange for fixed monthly payments from UPC.[1]

The Residual Contract Obligations currently include buyout payments to Indeck. The Residual Contract Obligations are also a known monthly payment stream. The Indeck buyout payments continue through September 2009. Residual Contract Obligations had also included buyout payments to Bay State Gas Company, but UPC completed these payments in December 2008.

The HQ Phase II Agreements require UPC to support the HQ Phase II facilities through October 2020. These facilities are part of one high-voltage, direct-current ("HVDC") interconnection between New England and Quebec. UPC has no obligation to support Phase I of these facilities. Currently, the costs for the maintenance and construction of these facilities are paid by Interconnection Rights Holders ("IRH") through support agreements between the IRH members and the owners of the HVDC transmission facilities. The Hydro-Quebec Support Payments include all costs incurred by UPC pursuant to the Hydro-Quebec Phase II Agreements, offset by any revenues received by UPC for sales of UPC's Hydro-Quebec Phase II entitlement. The Hydro-Quebec Support Payments are not a known payment stream because they are based on the cost-of-service of the Hydro-Quebec

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[1] The Mirant Agreement refers to the Portfolio Sale and Assignment and Transition Service and Default Service Supply Agreement by and among UPC, UES, and Mirant Americas Energy Marketing, LP. The Mirant Agreement was effective May 1, 2003 and also provided for the sale of Transition and Default Service power to UES through April 2006. Effective February 1, 2006, the Mirant Agreement was transferred to Mirant Energy Trading, LLC.

Phase II transmission facilities, which are offset by the short-term sales of transmission rights and capacity rights UPC acquires in return for the Hydro-Quebec Support Payments.

The True-Ups from Prior Periods reflect any differences in costs resulting from the reconciliation of estimated costs to actual costs under the CRP component of the Amended Unitil System Agreement. The True-Ups from Prior Periods also provides for the reconciliation of costs billed to UPC for services purchased in UPC's performance of the Unitil System Agreement, prior to May 1, 2003. The CRP estimates in the current filing reflect no True-Ups from Prior Periods.

Q. Please provide an estimate of each of the components of the CRP.

A. Details regarding the CRP are provided in Schedule FXW-3. On pages 1, 2, and 3 of Schedule FXW-3, UES presents itemized actual CRP and ASC charges as billed by UPC to UES for the period beginning May 2007 through April 2009 under the Amended Unitil System Agreement. On pages 3 and 4 of Schedule FXW-3, estimates for the 15-month period beginning May 2009 and ending July 2010 are presented. UPC bills UES on estimated data, prior to the beginning of the month of service. These estimates are trued-up to actuals on a two-month lag.

Q. Please provide a comparison of the CRP cost estimates provided in this filing with the CRP cost estimates provided for the calculation of the current SCC.

A. In Docket No. DE 08-040, UES presented a CRP cost estimate for the 15-month period beginning February 2008 through April 2009. In Table 1, below, I provide a comparison of the 15-month estimate provided in DE 08-040 to the 15-month estimate, covering the period beginning May 2009 through July 2010, provided in this filing.

Table 1. Comparison of CRP Estimates
Unitil Power Corp.

Line No.	Line Item Description	Prior Estimate Feb 2008 - Apr 2009	Current Estimate May 2009- Jul 2010	Change in Estimates
1.	Contract Release Payments (CRP) included in the SCC	$14,294,258	$8,329,884	($5,964,375)
2.	Portfolio Sales Charge	$6,000,000	$6,000,000	$0
3.	Residual Contract Obligations	$7,937,500	$2,304,333	($5,633,167)
4.	Hydro-Quebec Support Payments	$356,758	$25,551	($331,208)
5.	Subtotal (L. 2 through 4)	$14,294,258	$8,329,884	($5,964,375)
6.	True-up for estimate	$0	$0	$0
7.	Obligations prior to May 1, 2003	$0	$0	$0
8.	Total Contract Release Payments as billed by Unitil Power Corp.	$14,294,258	$8,329,884	($5,964,375)

Q. Please explain the lower estimates for Residual Contract Obligations and Hydro-Quebec Support Payments.

A. The estimate for Residual Contract Obligations is reduced because of the termination of the Indeck payments of $520,000 per month after September 2009 and the end of the Bay State payments of $12,500 per month since December 2008. After the September 2009 Indeck payment has been made, Unitil Power Corp. will no longer have Residual Contract Obligations, resulting in $5.6 million in reduced CRP for the upcoming period.

The estimate for Hydro-Quebec Support Payments reflects higher expected revenues from the sale of Hydro-Quebec transmission and capacity rights. These revenues have increased substantially since the estimates were prepared for DE 08-040.

Q. Please provide a report on the efforts by UPC to mitigate the stranded cost associated with the HQ Phase II Agreements.

A. UPC mitigates these costs through short-term sales of the transmission rights and capacity, which UPC is entitled to through its support of the HQ Phase II facilities. Currently, UPC resells its transmission rights on a short-term basis through a brokering agreement with Central Vermont Public Service Corporation ("CVPS"). Under this brokering agreement, CVPS offers UPC's transmission rights associated with the HQ Phase II facilities for sale on a short-term basis through the CVPS' OASIS website. CVPS has authority under this agreement to enter into binding sales of UPC's HQ transmission rights for transactions of one month or less in duration. UPC also has rights to Hydro-Quebec Interconnection Capability Credit ("HQICC"), pursuant to the ISO Tariff. UPC sells this capacity in the short-term markets by offering this capacity into the ISO New England Inc. ICAP Supply Auction. Please refer to Schedule FXW-5 for an itemized costs and revenue offsets, related to the HQ Phase II Support Agreements.

Q. Please provide an update of the Mirant Agreement.

A. Effective April 1, 2009, UPC, Mirant and Great Bay Power Marketing, Inc. ("Great Bay") terminated the purchased power agreement between UPC and Great Bay ("Great Bay PPA"). UPC had transferred the Great Bay PPA to Mirant under the Mirant Agreement. The Great Bay PPA would have continued through October 2010 had Mirant and Great Bay not desired to terminate it early. UPC consented to the termination, because it irrevocably and unconditionally releases UPC from any obligations or claims by Great Bay under the Great Bay PPA.

With the termination of the Great Bay PPA, Mirant has now fulfilled the contractual obligations of each contract in the portfolio, which was transferred to Mirant from UPC under the Mirant Agreement. As such, UPC has released Mirant from its obligation under the Mirant Agreement to provide a corporate guarantee. UPC's payments to Mirant under the Mirant Agreement continue through October 2010.

V. EXTERNAL DELIVERY CHARGE COSTS

Q. What costs are included in the EDC?

A. Schedule FXW-2, page 1 provides a description of the costs included in the EDC: 1) Third Party Transmission Providers (NU Network Integration Transmission Service); 2) Regional Transmission and Operating Entities; 3) Third Party Transmission Providers (NU Wholesale Distribution); 4) Transmission Based Assessments and Fees; 5) Load Estimation and Reporting System Costs; 6) Data and Information Services; 6) Legal Charges; 7) Consulting Outside Service Charges; and, 8) Administrative Service Charges.

I would like to expand on the descriptions of items 1), 2), and 3) of the Schedule.

The Third Party Transmission Providers (NU Network Integration Transmission Service) component of the EDC consists of Network Integration Transmission Service taken by UES and provided by the Northeast Utilities Companies pursuant to Schedule 21-NU of the ISO New England Inc. Transmission, Markets and Services Tariff (FERC Electric Tariff No.3) ("ISO Tariff").

The Regional Transmission and Operating Entities component of the EDC consists of all charges from ISO New England Inc. ("ISO"). These charges consist primarily of Regional Network Service, taken pursuant to the ISO Tariff. Other major costs (which are also billed by the ISO to UES) are various ancillary services allocated to transmission customers, such as VAR support, dispatch service, and black-start capability.

The Third Party Transmission Providers (NU Wholesale Distribution) component consists of Distribution Delivery Service ("DDS") charges with NU. DDS compensates Public Service Company of New Hampshire for the wheeling of power from the NU transmission system to UES' distribution system over certain facilities, which are classified as distribution facilities for accounting purposes and therefore not included in the NU transmission system rate base.

Q. Please provide a description of transmission owner expenses, which are included in the Regional Transmission rates in compliance with the Commission's Order No. 24,899 in Docket No. 08-092.

A. Please refer to Attachment FXW-1 of the filing. Attachment FXW-1 is several excerpted pages from the ISO Tariff, which provides descriptions of each component of transmission owner expenses, included in the regional transmission rate. Each New England transmission owner prepares the calculations for their includable transmission expenses for both its Pre-1997 and Post-1996 transmission facilities.

Q. Why has the recovery period for the EDC moved from May through April to August through July?

A. In UES' last annual reconciliation of the EDC and SCC, Docket No. DE 08-040, I estimated transmission costs for February 2008 through April 2009. I based this estimate upon actual transmission rates for February 2008 through May 2008 and estimated transmission rates for June 2008 through April 2009. The resulting EDC and SCC took effect on May 1, 2008. In mid-June 2008, UES was notified of the actual transmission rates to be in effect from June 2008 through April 2009, which were substantially higher than estimated in DE 08-040, prompting UES to file a revised EDC in Docket No. DE 08-092. In DE 08-092, the Commission directed UES to discuss the movement of the annual reconciliation filing date with the Commission Staff in order to provide more accurate cost estimates, based upon actual transmission rates, rather than estimated transmission rates.[2] UES filed a letter with the Commission, dated March 12, 2009, which indicated that UES and the Commission Staff had agreed to move the annual reconciliation filing in order that the new EDC and SCC take effect on August 1, 2009, rather than May 1, 2009. In this filing, I estimate transmission costs for May 2009 through July 2010. The estimates prepared in this filing are based on actual transmission rates from May 2009 through May 2010 and estimated rates from June through July 2010. Moving the effective date of the new EDC from May 1 to August 1 reduces the use of estimated transmission rates from 12 months out of 15 months estimated to 2 months out of 15 months estimated.

Q. What is UES' estimate for External Delivery costs, which is used in the calculation of the EDC rate?

A. Pages 2 through 4 of Schedule FXW-3 provide the External Delivery costs by month reflecting actual data from May 2007 through April 2009 and estimated data from May 2009 through July 2010. Actual data for the months May 2007 through January 2008 was included in UES' last rate and reconciliation filing,

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[2] Actual transmission rates are subject to change due to possible changes to New England transmission owner's return on equity, allowed by FERC.

Docket No. DE 08-040. Rather than present partial data beginning with February 2008, UES is presenting the full period.

Q. How do estimated EDC Costs beginning May 2009 through July 2010 compare to those which were estimated for February 2008 through April 2009 in Docket No. DE 08-040 and revised in Docket No. DE 08-092?

A. Please refer to the Table 2 on the next page for an itemized comparison of cost projections.

Table 2. Comparison of EDC Cost Estimates
Unitil Energy Systems, Inc.

Line No.	Line Item Description	Prior Estimate Feb 2008 - Apr 2009	Current Estimate May 2009 - July 2010	Change in Estimates
1.	Third Party Transmission Providers (NU Network Integration Transmission Service)	$2,876,923	$2,687,732	($189,191)
2.	Regional Transmission and Operating Entities	$12,760,629	$17,537,706	$4,777,077
3.	Third Party Transmission Providers (NU Wholesale Distribution)	$3,841,187	$3,679,544	($161,643)
4.	Transmission-based Assessments and Fees	$8,389	$2,000	($6,389)
5.	Load Estimation and Reporting System Costs	$156,000	$157,500	$1,500
6.	Data and Information Services	$18,750	$18,750	$0
7.	Legal Charges	$90,000	$74,500	($15,500)
8.	Consulting Outside Service Charges	$0	$0	$0
9.	Administrative Service Charges	($22,075)	($34,235)	($12,160)
10.	Total External Delivery Costs	$19,729,803	$24,123,498	$4,393,695

Q. Please explain the major increase in projected EDC costs.

A. I estimate Total External Delivery Costs for May 2009 through July 2010 to be $4.4 million higher than I estimated for February 2008 though April 2009. The cause of this increase is a $4.8 million increase in Regional Transmission and Operating Entities costs. The increase in Regional Transmission costs is partially offset by decreases in estimated costs of NU Network Service and DDS, totally approximately $0.35 million.

This increase in Regional Transmission costs represents a 37% increase in Regional Transmission costs over the prior period estimate, due to an increase in the Regional Network Service rate effective June 1, 2009. The increase in the Regional Network Service rate continues a trend of increasing transmission rates due to major investment in transmission infrastructure in New England. This investment has been required for transmission system reliability purposes. Increased transmission investment has the effect of increasing the amount UES pays for both NU Network Service and Regional Transmission.

The decrease of $189,191 in estimated NU Network Service costs is due to the decrease in the annual true-up costs included in the prior estimate. The NU Network Service true-up for 2007 was in excess of $1 million. The NU Network Service true-up for 2008 is expected to decrease to approximately $230,000. This decrease in annual true-up costs is partially offset by a projected increase in ongoing NU Network Service costs. At the time of this initial filing, the NU Network Service rates for effect beginning June 1, 2009 have not yet been provided to UES. When this data becomes available, I will revise the EDC cost budget and UES revise its rate calculations, if appropriate.

The decrease of $161,643 for DDS costs is due to a decrease in the minimum billing determinant due to a decrease in the annual peak system loads.

Q. What legal costs does UES expect to incur under the EDC?

A. I estimate that UES will incur $74,500 in EDC legal costs for the period beginning May 2009 through July 2010. This amount includes UES' estimates for monitoring FERC issuances and rulemakings, updates to Schedule 21-UES of the ISO Tariff required in order to provide for the interconnection of a new generator in UES' service territory, compliance with FERC's electronic tariff requirements and the cost of this proceeding. EDC legal costs estimate excludes any charges directly related to the design and implementation of Default Service supply. Any legal costs associated with procurement of Default Service are recovered through the Default Service Charge, in accordance with the settlement agreement approved in DE 05-064.

Q. Please provide the detail behind the estimate for the Administrative Service Charge.

A. Details regarding the ASC are provided in Schedule FXW-3 on lines 10 through 18. The ASC includes any costs incurred by UPC, relative to UPC's obligations under the Amended Unitil System Agreement, which are not otherwise assigned or assumed by UES. These costs include NEPOOL, ISO, and RTO costs, as well as legal, consulting, and other outside services. It does not include any internal costs of USC, UES or UPC.

Q. Did increased EDC costs contribute to the under-recovered balance in the EDC?

A. Yes. A portion of the under-recovered balance of the EDC reflects increased Regional Transmission costs due to the Regional Network Service rate changes effective June 1, 2009. This increased cost was not reflected in the current EDC, as the current EDC was designed to recover costs through April 2009, rather than through July 2009. The next change in Regional Network Service rates will occur effective June 1, 2010. This filing includes a projected increase for June and July 2010, based upon New England transmission owner's best estimates of the rate at that time.

VI. UPC COSTS AND REVENUES

Q. Has UPC prepared an accounting of the costs and revenues to UPC under the CRP and the ASC?

A. Yes. Schedule FXW-4 provides this accounting for the period beginning May 2007 through April 2009. UPC bills UES estimates of the CRP and ASC on the 25th of the month for the upcoming month. The estimated expenses are trued-up to actual expenses on a two-month lag basis. In order to calculate the true-up, UPC tracks the actual expenses, which comprise both the CRP and the ASC.

These actual expenses are compared to the estimated expenses to calculate the true-up for prior period.

Page 1 and 2 of 4 of the Schedule provides summary data of actual CRP and ASC expenses and revenues. Page 3 and 4 of 4 of the Schedule provides account level detail for adjustments to UPC's obligations prior to May 2003. This activity includes two credits from ISO, totaling approximately $30,000, relating to transmission return on equity refunds.

VIII. CONCLUSION

Q. Does that conclude your testimony?

A. Yes, it does.

The Transmission Revenue Requirement shall equal the sum of the PTO's (A) Return and Associated Income Taxes (including the Incremental Return and Associated Income Taxes for Post-2003 PTF Investment), (B) Transmission Depreciation Expense, (C) Transmission Related Amortization of Loss on Reacquired Debt, (D) Transmission Related Amortization of Investment Tax Credits, (E) Transmission Related Municipal Tax Expense, (F) Transmission Related Payroll Tax Expense, (G) Transmission Operation and Maintenance Expense, (H) Transmission Related Administrative and General Expenses, (I) Transmission Related Integrated Facilities Charges, minus (J) Transmission Support Revenue, plus (K) Transmission Support Expense, plus (L) Transmission-Related Expense from Generators, plus (M) Transmission Related Taxes and Fees Charge, minus (N) Revenue for Short-Term service under the OATT, (O) Transmission Rents Received from Electric Property and (P) Transmission Revenues from MEPCO Grandfathered Transmission Service Agreements. The Incremental Return and Associated Income Taxes for Post-2003 PTF Investment for each PTO shall be calculated using the investment base components specifically identified in Section A.1 of the formula below.

A. <u>Return and Associated Income Taxes</u> shall equal the product of the Transmission Investment Base and the Cost of Capital Rate. To calculate the Incremental Return and Associated Income Taxes for Post-2003 PTF Investment, Transmission Investment Base will only includes Sections II.A.1.(a), (d), and (e), in the manner indicated.

1. <u>Transmission Investment Base</u>

The Transmission Investment Base will be the year end balances of (a) PTF/HTF Transmission Plant, plus (b) Transmission Related General Plant, plus (c) Transmission Plant Held for Future Use, less (d) Transmission Related Depreciation Reserve, less (e) Transmission Related Accumulated Deferred Taxes, plus (f) Transmission Related Loss on Reacquired Debt, plus (g) Other Regulatory Assets/Liabilities, plus (h) Transmission Prepayments, plus (i) Transmission Materials and Supplies, plus (j) Transmission Related Cash Working Capital.

(a) <u>PTF Transmission Plant</u> will equal the balance of the PTO's PTF Investment in (a) Transmission Plant plus (b) HTF Transmission Plant. This value excludes (i) the PTO's Phase I/II HVDC-TF Leases, (ii) the portion of any facilities, the cost of which is directly assigned under Schedule 11 to the OATT, to the Transmission Customer or a Generator Owner or Interconnection

Requester, (iii) the Pre-1997 PTF gross plant investment associated with leased facilities occupied by the Phase II section of the Phase I/II HVDC-TF. In order to calculate the Incremental Return and Associated Income Taxes for Post-2003 PTF Investment, Post-2003 PTF Transmission Plant shall be separately identified.

(b) Transmission Related General Plant shall equal the PTO's balance of investment in General Plant multiplied by the Transmission Wages and Salaries Allocation Factor and the PTF/HTF Transmission Plant Allocation Factor.

(c) Transmission Plant Held for Future Use shall equal the PTO's balance of Transmission-related Plant Held for Future Use multiplied by the PTF/HTF Transmission Plant Allocation Factor.

(d) Transmission Related Depreciation Reserve shall equal the PTO's balance of Total Transmission Depreciation Reserve, plus the balance of Transmission Related General Plant Depreciation Reserve. Transmission Related General Plant Depreciation Reserve shall equal the product of the General Plant Depreciation

Reserve and the Transmission Wages and Salaries Allocation Factor. This sum shall be multiplied by the PTF/HTF Transmission Plant Allocation Factor. In order to calculate the Incremental Return and Associated Income Taxes for Post-2003 PTF Investment, Transmission Depreciation Reserve associated with Post-2003 PTF Investment shall equal the PTO's balance of Total Transmission Depreciation Reserve multiplied by the ratio of Post-2003 PTF Transmission Plant to Total Investment in Transmission Plant, excluding capital leases in the Phase I/II HVDC-TF Leases.

(e) Transmission Related Accumulated Deferred Taxes shall equal the PTO's electric balance of Total Accumulated Deferred Income Taxes, multiplied by the Plant Allocation Factor, further multiplied by the PTF/HTF Transmission Plant Allocation Factor. To calculate the Incremental Return and Associated Income Taxes for Post-2003 PTF Investment, Transmission Related Accumulated Deferred Income Taxes associated with Post-2003 PTF Investment shall equal the PTO's balance of total property-related accumulated deferred income taxes as recorded in FERC accounts 281 and 282, multiplied by the ratio of Total Investment in Transmission Plant, excluding Phase I/II HVDC-TF Leases, to Total Plant in Service excluding Phase I/II HVDC-TF Leases, further multiplied by the ratio of Post-2003 PTF Transmission Plant to Total Investment in Transmission Plant, excluding Phase I/II HVDC-TF Leases.

(f) Transmission Related Loss on Reacquired Debt shall equal the PTO's electric balance of Total Loss on Reacquired Debt multiplied by the Plant Allocation Factor, further multiplied by the PTF/HTF Transmission Plant Allocation Factor.

(g) Other Regulatory Assets/Liabilities shall equal the PTO's electric balance of any deferred rate recovery of FAS 106 expenses multiplied by the Transmission Wages and Salaries Allocation Factor, plus the PTO's electric balance of FAS 109 multiplied by the Plant Allocation Factor. This sum shall be multiplied by the PTF/HTF Transmission Plant Allocation Factor.

(h) Transmission Prepayments shall equal the PTO's electric balance of prepayments multiplied by the Transmission Wages and Salaries Allocation Factor and further multiplied by the PTF/HTF Transmission Plant Allocation Factor.

(i) Transmission Materials and Supplies shall equal the PTO's electric balance of Transmission Plant Materials and Supplies, multiplied by the PTF/HTF Transmission Plant Allocation Factor.

(j) Transmission Related Cash Working Capital shall be a 12.5% allowance (45 days/360 days) of the PTO's Transmission Operation and Maintenance Expense, Transmission Related Administrative and General Expense and Transmission Support Expense, to the extent that Transmission Support Expense exceeds Transmission Support Revenue included in Paragraph J of the formula.

2. Cost of Capital Rate

The Cost of Capital Rate will equal (a) the PTO's Weighted Cost of Capital, plus (b) Federal Income Tax plus (c) State Income Tax.

(a) The Weighted Cost of Capital will be calculated based upon the capital structure at the end of each year and will equal the sum of (i), (ii), and (iii) below. The Cost of Capital Rate to be used in calculating the Incremental Return and Associated Income Taxes for Post-2003 PTF Investment, shall only reflect item (iii) below and shall apply in the manner indicated below.

(i) the long-term debt component, which equals the product of the actual weighted average embedded cost to maturity of the PTO's long-term debt then outstanding and the ratio that long-term debt is to the PTO's total capital.

(ii) the preferred stock component, which equals the product of the actual weighted average embedded cost to maturity of the PTO's preferred stock then outstanding and the ratio that preferred stock is to the PTO's total capital.

(iii) the return on equity component, shall be the product of the allowed ROE of the PTO's common equity and the ratio that common equity is to the PTO's total capital. For pre-1997 and post-1996 assets, the ROE is 11.64%. In order to calculate the Incremental Return and Associated Income Taxes for Post-2003 PTF Investment, the incremental return on equity shall be the product of: (1) the PTO's incremental return on equity of 1.0% for plant investments associated with projects included in the RSP and placed in service by December 31, 2008 or otherwise permitted in Docket Nos. ER04-157, *et al.*; (2) any ROE incentive approved by the FERC under Order No. 679 for other plant investments, and (3) the ratio that common equity is to the PTO's total capital.[1]

(b) Federal Income Tax shall equal

$$\frac{(A+[(C+B)/D])(FT)}{1 - FT}$$

where FT is the Federal Income Tax Rate and A is the sum of the preferred stock component and the return on equity component, as determined in Sections II.A.2.(a)(ii) and (iii) above, B is Transmission Related Amortization of Investment Tax Credits, as determined in Section II.D., below, C is the Equity AFUDC component of Transmission Depreciation Expense, as defined in Section II.B., and D is Transmission Investment Base, as

[1] FERC Form-730 contains a list of transmission projects for which FERC has granted incentives under Order No. 679.

determined in Section II.A.1., above. In order to calculate the Incremental Return and Associated Income Taxes for Post-2003 PTF Investment, the incremental Federal Income Tax shall equal

$$\frac{(A' * FT)}{(1 - FT)}$$

where FT is the Federal Income Tax Rate and A' is the incremental return on equity component, as determined in Section II.A.2.(a)(iii) above.

(c) State Income Tax shall equal

$$\frac{(A+[(C+B)/D] + \text{Federal Income Tax})(ST)}{1 - ST}$$

where ST is the State Income Tax Rate, A is the sum of the preferred stock component and return on equity component determined in Sections II.A.2.(a)(ii) and (iii) above, B is the Amortization of Investment Tax Credits as determined in Section II.D. below, C is the equity AFUDC component of Transmission Depreciation Expense, as defined in Section II.B., D is the Transmission Investment Base, as determined in II.A.1., above and Federal Income Tax is the rate determined in Section II.A.2.(b) above. In order to calculate the Incremental Return and Associated Income Taxes for Post-2003 PTF Investment, the incremental State Income Tax shall equal

$$\frac{(A' + \text{Federal Income Tax})(ST)}{(1 - ST)}$$

where ST is the State Income Tax Rate, A' is the incremental return on equity component determined in Section II.A.2.(a)(iii) above, and Federal Income Tax is the rate determined in Section II.A.2.(b) above.

B. Transmission Depreciation Expense shall equal the PTF/HTF Transmission Plant Allocation Factor, multiplied by the sum of the PTO's Depreciation Expense for Transmission Plant, plus an allocation of General Plant Depreciation Expense calculated by multiplying General Plant Depreciation Expense by the Transmission Wages and Salaries Allocation Factor.

C. Transmission Related Amortization of Loss on Reacquired Debt shall equal the PTO's electric Amortization of Loss on Reacquired Debt multiplied by the Plant Allocation Factor, and further multiplied by the PTF/HTF Transmission Plant Allocation Factor.

D. Transmission Related Amortization of Investment Tax Credits shall equal the PTO's electric Amortization of Investment Tax Credits multiplied by the Plant

Allocation Factor, and further multiplied by the PTF/HTF Transmission Plant Allocation Factor.

E. Transmission Related Municipal Tax Expense shall equal the PTO's total electric municipal tax expense multiplied by the Plant Allocation Factor, and further multiplied by the PTF/HTF Transmission Plant Allocation Factor.

F. Transmission Related Payroll Tax Expense shall equal the PTO's total electric payroll tax expense, multiplied by the Transmission Wages and Salaries Allocation Factor, further multiplied by the PTF/HTF Transmission Plant Allocation Factor.

G. Transmission Operation and Maintenance Expense shall equal the PTO's Transmission Operation and Maintenance Expenses multiplied by the PTF/HTF Transmission Plant Allocation Factor.

H. Transmission Related Administrative and General Expenses shall equal the sum of the PTO's (1) Administrative and General Expenses multiplied by the Transmission Wages and Salaries Allocation Factor, (2) Property Insurance multiplied by the Transmission Plant Allocation Factor, and (3) Expenses included in Account 928 related to FERC Assessments multiplied by Plant

Allocation Factor, plus any other Federal and State transmission related expenses or assessments, plus specific transmission related expenses included in Account 930.1. This sum shall be multiplied by the PTF/HTF Transmission Plant Allocation Factor.

I. <u>Transmission Related Integrated Facilities Charges</u> shall equal the PTO's transmission payments to Affiliates for use of the PTF and HTF integrated transmission facilities of those Affiliates.

J. <u>Transmission Support Revenues</u> shall equal the PTO's revenue received for PTF and HTF transmission support but excluding the support payments to PTOs or their designee pursuant to Schedule 11 and excluding the support payments to PTOs or their designee pursuant to Schedule 12 Part 1(a) and Part B.2, and excluding support payments, if any, made to PTOs or their respective designee pursuant to Part II.C of this OATT.

K. <u>Transmission Support Expense</u> shall equal the expense paid by (1) PTOs, (2) Transmission Customers or (3) Related Persons pursuant to Section II.49 of the Tariff for PTF and HTF transmission support other than expenses for payments made for congestion rights or for transmission facilities or facility upgrades placed in service on or after January 1, 1997, where the support obligation is required to be borne by particular PTOs or other entities in accordance with the OATT. Transmission Support Expenses by any entity other than a PTO, included in this provision, shall be capped at that entity's annual payment for Regional Network Service or its Point To Point Service for each individual Point To Point transaction from the resource with which the support payment is associated.

L. Transmission-Related Expense from Generators shall equal the expenses from generators that both (1) the PTO Administrative Committee determines should be included as transmission expense as a result of the impact of such generators on reducing transmission costs that would otherwise be required to be paid by Transmission Customers and (2) are reflected in a filing made by the PTOs with the Commission under Section 205 of the Federal Power Act and accepted by the Commission for recovery under the OATT.

M. Transmission Related Taxes and Fees Charge shall include any fee or assessment imposed by any governmental authority on service provided under this Section which is not specifically identified under any other section of this rule.

N. Revenues for Short-Term service under the OATT shall be revenues distributed to each PTO for short term service provided under the OATT, received after March 1, 1999. These revenues will be credited pro-rata between pre-1997 and post-1996 PTF revenue requirements in proportion to pre-1997 and post-1996 PTF Transmission Plant.

O. Transmission Rents Received from Electric Property shall equal any Account 454 Rents from electric property, associated with PTF and HTF Transmission Plant as defined in Section II.A.1.(a) above but not reflected as a credit in Transmission Support Revenues in paragraph K of this Attachment.

P. Transmission Revenues from MGTSAs shall equal any MGTSA revenues recorded in Account 456.